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May 19, 2015 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Review of the 2013-2014 Annual Automatic Adjustment Reports**
Docket No. E999/AA-14-579

Dear Mr. Wolfe:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.

Attached is the Minnesota Department of Commerce, Division of Energy Resource's (Department or DOC) *Review of the 2013-2014 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE14 AAA). Each electric utility discussed in this report is being sent a public version. A trade secret version specific to each utility is being sent via electronic mail to the respective utilities.

The Department is available should the Minnesota Public Utilities Commission (Commission) have any questions about the FYE14 electric AAA herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/lt
Attachments

REVIEW OF 2013-2014 (FYE14)
ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. E999/AA-14-579

MAY 19, 2015

PUBLIC DOCUMENT

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I. OVERVIEW

This report summarizes the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) review of the automatic adjustment charges for the July 2013 - June 2014 (FYE14) reporting period, which were filed by five Minnesota electric utilities in compliance with Minnesota Rule 7825.2810. The Department offers recommendations to the Minnesota Public Utilities Commission (Commission) regarding the information contained in this report, which are summarized at the end of the report.

The utilities included in this report are:

- Dakota Electric Association (Dakota or DEA);
- Interstate Power Company – Electric Utility (Interstate Electric);
- Minnesota Power (Minnesota Power or MP);
- Otter Tail Power Company (Otter Tail or OTP); and
- Northern States Power Company d/b/a Xcel Energy, Incorporated – Electric Utility (NSP or Xcel Electric).

The five rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2013 to June 30, 2014, accurately adjusted their energy rates to reflect changes in fuel costs.

The Department also analyzed the utilities' procurement policies, dispatching procedures, cost-minimizing efforts, adjustment computations, and auditors' reports. The FYE14 reporting period coincides with the ninth full year of operation under the "Midcontinent Independent System Operator's Day 2 Energy Market" (MISO Day 2 Market). The Department dedicates Section VII of this report to addressing MISO Day 2 Market issues.

II. FILING REQUIREMENTS

A. MINNESOTA RULES

Pursuant to Minnesota Rule 7825.2810, subpart 1, the filing requirements for electric utilities include the following:

- Paragraph A – the base cost of fuel approved by the Commission in the utility's most recent rate case;
- Paragraph B – billing adjustment amounts charged to customers for each type of energy cost, such as nuclear, coal, or purchased power;

[1] The Commission granted Northwestern Wisconsin Electric Company (NWEC) a variance from the annual reporting requirements in Minnesota Rules 7825.2800 through 7825.2840 in its Order dated December 18, 2001 in Docket No. G,E999/AA-00-1027. Since the Commission granted this variance with no expiration date, it continues until revoked by the Commission.

- Paragraph D – total cost of fuel delivered to customers;
- Paragraph E – revenues collected from customers for energy delivered; and
- Paragraph G – amount of refunds credited to customers.[2]

Each reporting utility computed billing adjustments and total fuel costs on a system-wide basis. This approach is consistent with the methods used in the monthly fuel clause adjustment (FCA) filings, and the Commission approved this approach in previous proceedings. Therefore, the Department concludes that the Annual Automatic Adjustment Reports (AAA Reports) from all five reporting electric utilities comply with the Commission's filing requirements, as described in Minnesota Rule 7825.2810, subpart 1.[3]

Further, Minnesota Rule 7825.2820 requires the following:

> By September 1 of each year, all gas and electric utilities shall submit to the commission an independent auditor's report evaluating accounting for automatic adjustments for the prior year commencing July 1 and ending June 30 or any other year if requested by the utility and approved by the commission.

All electric utilities submitted auditors' reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors.

Minnesota Rule 7825.2830 requires all electric utilities to "submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter." All utilities complied with this requirement.

Minnesota Rule 7825.2840 requires all electric utilities to "provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all interveners in the previous two general rate cases." All utilities complied with this requirement.

In the next section, the Department summarizes the fuel cost projections submitted by each of the electric utilities that made annual fuel cost filings.

B. SUMMARY OF FUEL COST PROJECTIONS

Dakota does not own generation and transmission resources, and instead purchases its power from Great River Energy, its wholesale generation and transmission provider; thus, the figures for Dakota are not directly comparable to the projections for other utilities.

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[2] Paragraphs C and F pertain to natural gas utilities.

[3] In the discussion of allocations throughout this report, the Department notes that the two categories to which costs and revenues are allocated are retail customers and wholesale transactions. Allocations to retail customers are reflected directly in FCA rates, whereas allocations to the wholesale sector may or may not be reflected in rates charged to wholesale customers. For purposes of the ratemaking elements of this report, it is helpful to think of "wholesale transactions" as being similar to shareholders or another non-jurisdictional entity.

Dakota projects that its purchased power (energy and capacity) costs will **[TRADE SECRET DATA HAS BEEN EXCISED]**

Interstate Electric projects its energy costs to **[TRADE SECRET DATA TRADE SECRET DATA HAS BEEN EXCISED]**[4]

Minnesota Power projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED].**

Otter Tail projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED]**

Xcel Electric projects its energy costs, including fuel, purchases and sales to **[TRADE SECRET DATA HAS BEEN EXCISED]**

These fuel cost projections are summarized in Attachment E1.[5]

III. COMPLIANCES

The Department addresses the reports listed below in this section. The Department notes that the analysis of compliances related to the MISO Day 1 and Day 2 markets are discussed in Section VI *Effects of the MISO Day 1 Market on Minnesota Ratepayers* and in Section VII *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

- Investigation of Xcel Electric's Practices Regarding Energy Marketing and the Fuel Clause in Docket No. E002/CI-00-415.

- Natural Gas Financial Instruments (Xcel Electric's compliance filing) in Docket Nos. E002/M-01-1953 and E999/AA-02-951.

- Wind Curtailment Report (Xcel Electric's compliance filing) in Docket Nos. E002/M-00-622 and E002/M-02-51.

- FCA Settlement Agreement (Xcel Electric's compliance filing) in Docket No. E002/GR-05-1428.

- History of Nuclear Fuel Sinking Fund in Docket No. E002/M-81-306.

- Otter Tail's Enbridge Energy Issues in Docket No. E017/M-06-1332.

- Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs) (Docket Nos. E002/M-08-1098, E002/M-10-486 and E999/AA-10-884)

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[4] These projections assumed that IPL would continue to serve its retail customers; in Docket No. E001, *et. al.*/PA-14-322, the Commission granted IPL's request to transfer these customers to the Southern Minnesota Electric Cooperative, SMEC.

[5] Dakota and MP provided their data based on a fiscal year while IPL, OTP and Xcel Electric used a calendar year.

- Maintenance Expenses of Generation Plants (Docket No. E999/AA-06-1208).

- Plant Outages Contingency Plans (Docket No. E999/AA-08-995).

- Sharing Lessons Learned Regarding Forced Outages (Docket No. E999/AA-10-884).

- OTP's FCA True Up (E017/M-03-30).

- Xcel's Curtailment of WM Renewable Energy (Docket No. E002/M-10-161).

- Report on Purchased Power Agreement (PPA) with Manitoba Hydro (Docket No. E015/M-10-961).

- Quarterly Reporting on Accounting Costs of Interstate Electric's Auction Revenue Rights (ARR) (Docket No. E001/M-09-455).

- Economic Comparison of Interstate Electric's Generation Resources (Docket No. E999/AA-10-884).

The Department discusses each of these items below.

A. INVESTIGATION OF XCEL ELECTRIC'S PRACTICES REGARDING ENERGY MARKETING AND THE FUEL CLAUSE IN DOCKET NO. E002/CI-00-415

In its Order dated June 15, 2001, in Docket No. E002/CI-00-415, Ordering Paragraph No. 2, the Commission required Xcel Electric to provide a monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July, and August with its AAA report to ensure that the Company is reasonably allocating generation costs between retail and wholesale customers. Xcel Electric included this data for the first time in its annual reporting filings on September 4, 2001 in Schedule 2 of Attachment G. Xcel Electric also provided this data in its annual reporting filings for all years to date.

In its filing for FYE14, the monthly generation costs allocated to retail and wholesale customers was provided for the above stated months of 2014.[6] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2014.

The Department reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector, and noted that the information filed by the Company appears to comply with the requirements of the Commission's Order. Xcel's data indicated that for all three months in 2014, the retail average generation costs were less than the average generation costs allocated only to the wholesale sector and the average costs for both the wholesale and retail customers.

[6] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing of Docket No. E999/AA-14-579 on September 2, 2014, and was subsequently provided in full in a supplemental filing in the same Docket on October 3, 2014.

The Department notes that a high level check of the allocations between retail and wholesale customers remains helpful to ensure that lowest cost resources are assigned to retail customers moving forward. Based on our review of the 2014 data, the Department recommends that the Commission approve Xcel Electric's compliance filing on the high level cost allocation test between wholesale and retail customers for June, July, and August of 2014. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

B. NATURAL GAS FINANCIAL INSTRUMENTS: XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/M-01-1953 AND E999/AA-02-951

On March 20, 2002 in Docket No. E002/M-01-1953, the Commission approved a request by Xcel Electric for accounting treatment and related processes necessary to separate the cost accounting for natural gas financial instruments purchased to meet the needs of jurisdictional retail electric and natural gas customers from the natural gas financial instruments purchased to support Xcel Electric's non-jurisdictional wholesale electric sales activities. With Commission approval, Xcel Electric proposed to submit a written request that their external auditors specifically examine these transactions in preparation of the auditor's report to be submitted with Xcel Electric's FYE02 electric and natural gas AAA reports and PGA true-up to be filed September 1, 2002, to ensure that the accounting separation is implemented appropriately.

Xcel Electric's FYE14 AAA report also includes a copy of the prescribed letter by Xcel Electric to its external auditors.[7] The report included a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[8] which concluded:

> In our opinion, such Schedule presents, in all material respects, the fuel adjustment clause factors of the Company for the period July 1, 2013 to June 30, 2014, as calculated in accordance with the criteria established by the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2700 to 7825.2800 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5-91.2, and 5-91.3 of the electric rates filed by the Company with the Commission.

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

C. WIND CURTAILMENT REPORT

In the past, various Commission Orders emphasized reporting and regulatory review of the curtailment practices used by Xcel Electric in connection with its wind Purchase Power

[7] See Part F, Section 1 of Xcel Electric's FYE14 AAA report.
[8] See Part F, Section 2 of Xcel Electric's FYE14 AAA report.

Agreements (PPAs). The Department notes that our May 10, 2005 extensive review of Xcel's wind curtailments in Docket No. E999/AA-04-1279 provides a thorough background on the issue of wind curtailment payments.

For this report, the Department concludes that Xcel Electric is substantially in compliance with the Commission's April 4, 2006 Order *Adopting Treatment of Curtailment Payments to Wind Developers through FCA and Requiring Compliance Filings* in Docket No. E999/AA-04-1279. In particular, Xcel Electric included in its FYE14 AAA filing a report on its projected wind curtailment payments over the 2014-2018 period for planned and existing projects and any commitments made to update the system.[9]

The Department reviewed Xcel Electric's wind curtailment data. Curtailment costs have been substantially reduced from their peak during FYE05 from 16.50 percent of the total cost of wind, including curtailments, to 8.32 percent in FYE08, 2.42 percent in FYE09, and 1.77 percent in FYE13.[10] However, curtailment costs increased substantially, to 8.59 percent in FYE14.

The Department notes that Xcel Electric's FYE14 wind curtailment report (Wind Report) indicates that most of the curtailment payments (about 99 percent of a total of about $15.6 million) is related to MISO directives (curtailment reason code 3). However, in light of the substantial increase in curtailment payments, the Department requested Xcel Electric through discovery to:[11]

1) Identify and fully describe each and all events that resulted in the above-referenced curtailment payments.

2) For each of the events provided in response to question 1, please provide a table (hard copy and live Excel spreadsheet) identifying (a) the curtailed wind facilities, (b) the amount of curtailment (MWh) and curtailment payments ($) made to each of the affected facilities as well as the total amount of curtailment (MWh) and curtailment payments ($) for the period July 1, 2013-June 30, 2014.

3) For each of the events provided in response to question 1, please explain in layman's terms why and how the event caused the need to curtail these specific wind facilities.

4) For each of the events provided in response to question 1, please identify and describe any and all additional preventive steps Xcel could have taken to either eliminate or alleviate the need to curtail wind facilities. If none, please fully explain and justify your answer.

[9] Part H, Section 5, Schedule 2 of Xcel Electric's FYE14 AAA report.
[10] Source: Attachment E2.
[11] Source: Department's April 10, 2015 information request No. 33.

5) In light of your response to question 4 and for each event provided in response to question 1, please fully explain and justify whether and why the corresponding total amount of curtailment payments identified in response to question 2 were prudently incurred.

6) For each of the events provided in response to question 1, please identify each and all wind facilities that could have been curtailed in place of those that were curtailed (see Xcel's response to question 2 above). If none, please fully explain and justify your answer.

7) If your response to question 6 indicates that other wind facilities could have been curtailed, please fully explain and justify for each of the events provided in response to question 1 whether and why the curtailed wind facilities and their respective level of curtailment (see Xcel's response to question 2 above) were a least cost option.

8) In light of your response to question 7 and for each event provided in response to question 1, please fully explain and justify whether and why the corresponding total amount of curtailment payments identified in response to question 2 were prudently incurred.

Xcel Electric requested a one-month delay to respond to the Department's information request and suggested to limit the discovery to "curtailment codes other than 3."[12]
In response, the Department noted its concern that Xcel had not done a better job documenting the reasons for the significant increases in wind curtailment costs, given the importance this issue has received in the past, and given Xcel's burden of proof to show that its FCA rates are reasonable. The Department noted that "It might help to think of these costs as non-fuel costs that increased seven-fold during a year when Xcel did not have a rate case, requiring justification to Xcel's management why the costs increased and hurt the Company's bottom line"

To help Xcel explain the increase in curtailment costs to Commission, the Department allowed Xcel until April 30, 2015 to provide its response and clarified its discovery as follows:

1) Identify and fully describe the events that resulted in the FYE14 curtailment payments. (Note that Xcel's initial filing in the FYE14 AAA docket appears to identify the following events: "work-related to a storm in July 2011, severe ice storm in April 2013 and emergency maintenance on several

[12] Xcel Electric's April 20, 2015 email and the Department's April 21, 2015 response are attached as Attachment E3.

high-voltage transformers." Please provide dates for these events.)

2) Identify, for each such event, the curtailed wind facilities, the total FYE14 amount of curtailments (MWh) and curtailment payments ($) made to each of the curtailed facilities.
3) For each such event, explain in layman's terms why and how the event caused the need to curtail these specific wind facilities.
4) The other questions are designed to help Xcel explain whether Xcel could have been more proactive in alleviating the occurrence and/or consequences of each such events and whether Xcel could have used a lower cost option to address the specific need for curtailment as a result of each such events.

The Department only received Xcel Electric's response to discovery on May 8, 2015 and was unable to complete its review and analysis of Xcel Electric's response to the Department's information request No. 33 in time to include it in this report. The Department will review Xcel's response to discovery and file its analysis in our response comments to the IOUs' reply comments.

D. FCA SETTLEMENT AGREEMENT (XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/GR-05-1428)

During Xcel's Electric's 2005 rate case (Docket No. E002/GR-05-1428), the Minnesota Chamber of Commerce and the Large Industrial Group entered into an FCA Settlement Agreement with Xcel Electric. The settlement included several commitments by Xcel Electric intended to provide customers with more information and analysis to enhance the ability of customers to plan for and manage volatility in fuel costs. The additional information and analysis included more discussion on Xcel Electric's plans for hedging fuel or energy purchases and more analysis of Xcel Electric's attempts to mitigate volatility, cover risks associated with planned outages and optimize hedging of congestion costs. The additional information also included a dollar-per-megawatt-hour ($/MWh) price to show the rolling 12-month average cost quarterly based on expected market conditions.

The Department notes that Xcel Electric's FYE14 AAA filing included additional information and analysis to address the FCA Settlement Agreement approved by the Commission in Docket No. E002/GR-05-1428. The Department was not a party to this settlement, and thus invites comments on this information from those who were parties, regarding whether there are any concerns that need to be addressed.

E. HISTORY OF NUCLEAR FUEL SINKING FUND IN DOCKET NO. E002/M-81-306

Pursuant to the Commission's Order dated July 14, 1981 of the referenced docket, Xcel Electric included the required information in Part H, Section 1 of its FYE14 AAA filing. Xcel's filing provided history of nuclear fuel interim storage and disposal expenses included in the determination of electric automatic adjustment charges. Xcel Electric shows payments to the Department of Energy (DOE), DOE credits, and beginning and ending balances for disposal costs and permanent disposal costs.

For background, the following are the four nuclear charges:

- DOE Yucca Mountain Permanent Disposal Costs, which is a $1 million per kWh fee that is collected via the FCA; the Department notes that effective May 16, 2014 the DOE is no longer allowed to charge the spent nuclear fuel disposal fee and as a result this reporting period is the last where the Company paid or collected this DOE fee via the FCA[13];
- Interim Storage Costs that were collected from ratepayers and then used for Xcel Electric's Prairie Island Dry Cast Storage Project;
- Payments to the DOE for process plant enrichment services, where Xcel Electric was overcharged for the period 1986 to 1993, resulting in a $1.7 million refund to ratepayers through the February 2006 FCA; and
- Nuclear Decommissioning Costs, which were collected through Xcel Electric's base rates. Xcel recommended in its decommissioning study in Docket E002/M-11-939 a 36-year decommissioning period and an annual accrual of $11.2 million for decommissioning starting January 1, 2013. The Commission's December 4, 2012 Order approved a 60-year decommission period and a $14.2 million annual decommission accrual starting January 1, 2013.

Based on our review of Xcel Electric's Schedule 1 for the FYE14 AAA, the Department concludes that there are no significant changes from Xcel's previous FYE13 AAA filing. The DOC notes that total permanent disposal costs paid to DOE were $449 million as of June 30, 2014, with annual amounts for recent years between $10.6 and $12.9 million, with an average of $11.7 million over the past five fiscal years.[14]

a) The Department notes that Xcel Electric entered into a July 5, 2011 Settlement with DOE regarding DOE's partial breach of its contract to take spent nuclear fuel beginning January 31, 1998. Xcel Electric received compensation from DOE for the following cost categories: a) any additional pool storage and other plant modifications;
b) dry cask storage and costs directly related to such storage (*e.g.*, internal labor, overhead, operating and maintenance, and training and security); and
c) additional property taxes from the on-site dry cask storage or other plant modifications.

The refund amounts, allocations, and other related issues are further discussed in Docket E002/M-11- 807.

On December 16, 2011, the Commission issued its Order approving the first DOE payment to Xcel to be refunded to customers. The DOC notes that a second DOE payment was made to Xcel Electric and was refunded to customers in March 2012. In November 2012 Xcel

[13] United States Court of Appeals for the District of Columbia suspended the collection of the nuclear disposal fees that are assessed annual on nuclear power plant operators by the DOE.
[14] Part H Section 1, Schedule 1, Page 1. Xcel Energy's Annual Report, Docket No. E999/AA-14-579.

received its third payment from DOE, and received its fourth payment on November 7, 2013. The Company and the DOE negotiated an extension to the Settlement Agreement that allowed for the recovery of damages through 2016. These DOE refund payments will be placed in Xcel's decommissioning fund as payment for decommissioning costs with excess DOE payments used to offset future decommissioning costs.

The Commission allowed Xcel to place funds disbursed by DOE in the fourth payment in 2013 in excess of the decommissioning accrual amount into an external escrow account to preserve the Commission's option to use the funds as part of the rate moderation proposal presented by the Company in the current rate case, or until such time as the Commission determined the appropriate use for those funds.[15]

This fourth payment, along with the fifth DOE payment under the DOE settlement that Xcel received on December 18, 2014, which Xcel contributed into the escrow fund,[16] amount to total excess DOE funds of $27,843,837. The Commission authorized Xcel to use this amount to moderate the rate increase for the 2015 step in Xcel's current Rate Case Docket No. E002/GR-13-868.[17]

The Department notes in the current Xcel decommissioning filing in Docket No.E002/D-14-761 a decommission accrual of $14,030,831 with an effective date of January 1, 2016 is being requested by the Company, and was recommended by the Department to be approved by the Commission. Additionally, the Company has requested the elimination of the escrow account by transferring the balance into the qualified decommissioning trust. The Company also committed in its decommissioning filing to use DOE Settlement proceeds for paying the approved decommissioning accrual and making future filing to the Commission for addressing any DOE Settlement proceeds that exceed the decommissioning accrual.

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

F. OTTER TAIL'S ENBRIDGE ENERGY ISSUES IN DOCKET NO. E017/M-06-1332

The Commission's Order dated January 16, 2007 in Docket No. E017/M-06-1332 approved an electric service agreement (ESA) between Otter Tail Power and Enbridge Energy. The Commission's Order requires Otter Tail Power to report in its AAA report the following information:

- the amount of incremental energy purchased by Enbridge Energy under the Large General Service (LGS) Rider,
- the retail rate paid by the customer, and
- the retail rate of the energy had System Marginal Energy Pricing been used to determine the retail rate paid by the customer.

[15] December 18, 2013 Order in Docket No. E002/M-11-807
[16] Docket No. E002/D-14-761
[17] Campbell Opening Hearing Statement on pages 3-4.

As explained in Docket No. E017/M-06-1332, the principal change from the previous ESA to the current ESA was the change from pricing incremental energy in the LGS Rider on a System Marginal Energy Pricing (SMEP) basis to a Fixed Rate Energy Pricing (FREP) basis. These reporting requirements allow for monitoring the impact of the change from SMEP to FREP on Enbridge Energy's electrical usage.

The 2014 data shows that Enbridge Energy continues to purchase a significant amount of incremental energy. Had SMEP been used to determine the rate for the same amount of energy Enbridge Energy purchased for the July 2013 to June 2014 period, Enbridge would have paid less than it paid under FREP. As the Department has concluded in previous AAA reports, the information to date does not suggest that FREP pricing is resulting in higher energy use by Enbridge Energy.

The Department recommends that the Commission accept Otter Tail Power's Enbridge Energy compliance filing in this docket.

The Department also notes that Otter Tail Power requested that consideration be given to drop this compliance reporting requirement. The Company has provided data regarding this change in pricing for several years, which has allowed the Department several opportunities to review pricing data. In those reports, the Department has consistently concluded that there is no indication that this pricing change affected Enbridge Energy's energy use. Thus, the Department does not have concerns with this change in pricing and recommends that Otter Tail Power no longer be required to report this information.

G. OFFSETTING REVENUES AND/OR COMPENSATION RECEIVED BY IOUS (DOCKET NOS. E002/M-08-1098, E002/M-10-486 AND E999/AA-10-884)

In its January 29, 2009 Order in Docket No. E002/M-08-1098 (2009 Order), the Commission required Xcel Electric to report in future AAA filings all revenue from any source as a result of a Renewable Energy Purchase Agreement with Koda Energy, and to itemize any such revenue by source and amount.

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[18] Therefore, the Department concludes that Xcel Electric complied with the 2009 Order.

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

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[19] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

[18] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE14 AAA report.
[19] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE14 AAA report.

In its April 6, 2012 Order in Docket No. E999/AA-10-884 (2012 Order), the Commission required the IOUs to report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the IOUs should clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.

The IOUs indicated that they passed any such offsetting revenues or compensation through the fuel clause. Therefore, the Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (ordering point 8).

The Department will continue to monitor the treatment of offsetting revenues and compensation recovered by the utilities in future filings.

H. MAINTENANCE EXPENSES OF GENERATION PLANTS (DOCKET NO. E999/AA-06-1208)

In its February 6, 2008 Order (2008 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

This requirement stems from the drastic increase in IOUs' outage costs during FYE06 and FYE07.[20] The Commission agreed with the Department and Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance, and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 2008 Order at 5.

These high levels of outages raised the issue of whether the IOUs are spending as much to maintain their generation plants as they are charging to their customers in FCA rates which allow for automatic adjustment of rates to reflect increases in costs.

As summarized below, the Department notes that only MP and Xcel Electric are spending more on operation and maintenance (O&M) costs than they are charging to their customers in rates.[21] While Table 1 appears to indicate that Xcel has not been spending more than budgeted, this appearance is caused by Xcel's 2013 rate case (Docket No. E002/GR-13-868). Xcel spent more on maintenance in 2013 than budgeted, but the 2011-2013 Historical Average for Xcel is negative because Xcel's most recent rate case resulted in a substantial increase to the Maintenance expense budget for Xcel. Even with the increased 2013 O&M spending, the 3-year average actual spending is still less than the current maintenance budget. Rate case and historical averages are calculated based on data provided by IPL, OTP, MP and Xcel. The Department notes that IPL has not met or exceeded their budgeted maintenance costs since IPL's 2010 rates case, and OTP has not met or

[20] Attachment E4 shows that the outage costs substantially decreased as a share of energy costs from FYE07 to FYE11, but have begun to rise again in FYE13 and FYE14 for some Utilities.
[21] Attachment E5 provides an annual breakdown of the IOUs' maintenance expenses of generation plants.

exceeded their budgeted maintenance costs since 2009. While OTP's outage costs as a percentage of fuel and purchased power costs have remained low, IPL's outage costs were much higher in FYE14.

Table 1: Comparison of Generation O&M Costs

	Test Year	Rate Case	Historical 2011-2013 Average	Difference from Rate Case
IPL	2009	$ 3,779,345	$ 3,387,589	$ (391,756)
MP	2010	$ 33,619,194	$ 41,739,946	$ 8,120,752
Xcel Electric	2014	$ 193,685,565	$184,091,165	$ (9,594,400)
OTP	2009	$ 13,142,720	$ 11,780,406	$ (1,362,314)

Due to the link between the level of O&M expenditures on facilities and forced outages of facilities, and due to different ratemaking incentives, which encourage utilities to minimize O&M costs between rate cases while providing little to no incentive to minimize replacement power costs, the Department intends to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' most recent rate cases in future AAA filings.

I. PLANT OUTAGES CONTINGENCY PLANS (DOCKET NO. E999/AA-08-995)

In its March 15, 2010 Order, the Commission required all IOUs to work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages.

This requirement stems from the drastic increase in OTP's energy costs in November ($39/MWh) and December 2007 ($51.20/MWh) due to a contractor's failure to perform the contracted work for a planned outage of the Big Stone plant.

In its FYE07 AAA report, the Department requested suggestions from the utilities regarding improving outage-related contracts to better protect ratepayers. In response, the utilities appeared to jointly agree that "while we attempt to include contract terms or performance bonds to indemnify us for delays or lack of performance, requiring a contractor to indemnify us for replacement energy cost is cost prohibitive." (MP's September 29, 2009 reply comments at 9). However, utilities did not provide evidence to support that position, nor did they suggest other methods to protect ratepayers from paying for high replacement power costs during forced (unforeseen) outages.

The Department attempted to generate a useful discussion of ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities.

Finally, the Department recommended that utilities, at a minimum, identify and work with contractors that have reasonable contingency plans to alleviate the risk of delays or lack of performance.

Xcel Electric is the only utility that discussed "the lessons learned and the contingency plans developed by the utility to mitigate against future risk of delays or lack of performance, when contractors perform poorly and increase costs during plant outages."

Xcel Electric provided the following report:[22]

> 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

[22] Part K, Section 3 of Xcel Electric's FYE14 AAA report.

> manner. Therefore, we will continue to identify and work with these types of contractor issues on a going forward basis.

Even though the discussion does not address the issue of liability for replacement power costs, the Department appreciates the specific information that Xcel Electric provided.

The Department notes that it has also raised the issue of protecting ratepayers from paying high costs for replacement power in its FYE13 AAA report in association with the lessons learned regarding forced outages and made additional recommendations in the corresponding Docket No. E999/AA-13-599.[23] The Department looks forward to discussing these issues with the Commission in those dockets. In addition, the Department discusses both issues further in the next section, based on the most recent information available.

Based on what is known at this time, the Department expects to continue to monitor the IOUs' plant outages contingency plans in future AAA filings.

J. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES (DOCKET NO. E999/AA-10-884)

In its April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the Commission required the IOUs to provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E-999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

In this docket, Xcel Electric, MP, IPL and OTP provided the required information. Therefore, the Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (ordering point 22) in reporting information.

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

As indicated in Attachment E16 and in Dockets E999/AA-09-961, E999/AA-10-884, E999/AA-11-792, E999/AA-12-757 and E999/AA-13-599, utilities have generally resisted suggestions for minimizing forced outages, sharing lessons learned, exploring efforts to hold contractors accountable for contractor errors that lead to forced outages, or procuring business interruption insurance. In addition to this resistance, utilities' lack of alternative solutions for protecting ratepayers also speaks loudly.

Given this background, the Department believes that, at least until the FCA incentive is changed (see Docket E999/AA-12-757 for discussions of amendments to the FCA), the

[23] DOC's December 31, 2014 response comments in Docket No. E999/AA-13-599.

reasonableness of charging ratepayers for replacement power costs during any forced outage should be associated with the IOU's ability to learn from past outages as well as to justify the specific preventive steps taken as discussed in Docket E999/AA-13-599.

The Department looks forward to discussing the general issue of consumer protection and various ways to accomplish that goal when the Commission considers the comments in Dockets E999/AA-12-757 and E999/AA-13-599.[24]

K. FCA TRUE-UP REPORT IN DOCKET NO. E017/M-03-30

In its Order dated December 27, 2006, the Commission provided specific true-up procedures applicable to the Otter Tail's annual true-up filings.

Regarding this reporting period, on July 31, 2014, Otter Tail submitted a compliance report and proposal to implement a true-up debit of $0.0008 per kWh. In Comments filed on September 12, 2014, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up debit. The Commission's September 25, 2014 Order approved Otter Tail's true-up increase in rates beginning September 1, 2014.

L. CURTAILMENT OF WM RENEWABLE ENERGY (DOCKET NO. E002/M-10-161)

In its April 30, 2010 Order (2010 Order) in Docket No. E002/M-10-161, the Commission required Xcel Electric to report on any curtailment of wind energy from WM Renewable Energy, including the reasons for any such curtailments and the amounts paid, in Xcel Electric's monthly fuel clause adjustment filings.

Xcel Electric stated that "the Company is not aware of any curtailments or curtailment payments during the current reporting period."[25] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

M. REPORT ON MP'S PPA WITH MANITOBA HYDRO (DOCKET NO. E015/M-10-961)

The Commission's Order in Docket No. E015/M-10-961 required MP to provide in its annual AAA report information regarding the number of times certain energy products were offered by Manitoba Hydro to MP, the number of times such offers were accepted, and various energy price comparisons. The purpose of the data is to assess whether the costs of the Manitoba Hydro products are least cost.

Based on the Department's review of MP's AAA annual report, the Department concludes that MP is in compliance with the Commission's Order in Docket No. E015/M-10-961. MP's information indicates that costs of Manitoba Hydro products were least cost during this reporting period.

[24] *Id.*
[25] Source: Part H, Sections 1-8, page 5 of 5 of Xcel Electric's FYE13 AAA report.

N. QUARTERLY REPORTING ON ACCOUNTING COSTS OF INTERSTATE ELECTRIC'S ARR (DOCKET NO. E-001/M-09-455)

The Commission's Order in Docket No. E-001/M-09-455 required Interstate Electric to file the same quarterly reporting regarding the costs and benefits of transactions involving Auction Revenue Rights (ARR) that it files with the Iowa Utilities Board pursuant to the Board's *Order Granting Addendum to Waiver and Requiring Quarterly Reports* (March 11, 2009) in Docket No. WRU-2009-0011-0150.

In 2009, the Company proposed a new method for accounting the costs and benefits of transactions involving ARRs.

In accordance with the quarterly ARR transaction reports established with the October 2, 2009 Commission Order in Docket No. E-001/M-09-455, the Department requested information from the Company regarding the accounting of costs associated with ARRs to confirm the flow of ARR transactions through the fuel cost adjustment (FCA). The Company responded to the information requests with data confirming the inclusion of ARR transactions in the MISO charge types that are included with the FCA line item 'FTR Transaction.' The Department subsequently spoke with the Company to clarify the treatment and location of the ARR transactions within the line items of the MISO charges provided by the Company.[26]

The Department ensured compliance with the Commission Order in Docket No. E-001/M-09-455 regarding the flow through of ARRs in the FCA and concludes that Interstate Electric's FCA encompasses the ARR revenue. The Department requested a detailed overview of the June 2014 FCA to explicitly identify where the $2,312,561.16 of ARR Low Load Revenue was included in the FCA. The Company completed a supplement to the Department's original information request with the information.[27] The Department reviewed the submitted supplement from the Company, and determined that ARR revenue was flowed through the FCA correctly.

The Department recommends that in the future, the Company may wish to consider providing a separate line item for ARR transactions in order to increase the transparency of the flow through.

The Department recommends that the Commission accept Interstate Electric's compliance with the Order in Docket No. E-001/M-09-455. The Department will review Interstate Electric's continued compliance with this requirement in the FYE15 AAA report.

O. ECONOMIC COMPARISON OF INTERSTATE ELECTRIC'S GENERATION RESOURCES (DOCKET NO. E999/AA-10-884)

In Exhibit H, Page 23, IPL addresses the following specific reporting requirement from the April 6, 2012 Commission Order in Docket No. E999/AA-10-884 to be incorporated into annual automatic adjustment reports:

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[26] *Id,* Attachment C.

[27] Supplemental Response of Interstate Power and Light Company to MN DOC Information Request No. 29.

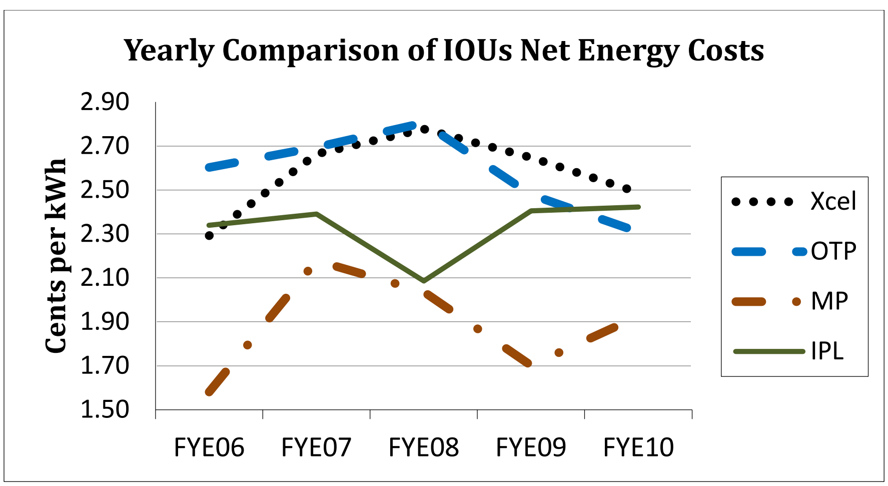
(13) Interstate shall explain in future filings why it does not have economic generation resources comparable to other utilities in the MISO footprint and explain how this effects what happens when there are outages on its system.

The Company stated in its FYE14 AAA filing:[28]

> IPL maintains that the appropriate proceedings to examine the Company's average cost of energy are the Integrated Resource Plan proceedings. IPL notes that the Commission did not issue an order point on this issue in its order in Docket No. E-999/AA-11-792 and the Department did not address this issue in its comments in Docket No. E999/AA-12-757, following information that was provided by IPL in the 2011-2012 AAA filing.

In its 2010 Comments the Department initially brought this issue to light, and inquired about the cost of generation resources in the IPL fleet. Primarily, the concerns of the Department in that line of inquiry were precipitated by the high energy costs seen by IPL from the period of FYE06 to FYE10 as seen in the figure below:[29]

Figure 1: Comparison of Energy Costs 2010



The Department was concerned at the time about the energy costs in FYE10 for IPL, noting that they were higher than any of the previous years' costs, which were driven in part by the relatively high level of outage costs. The relationship between maintenance of generation resources and its effect on energy costs was a point raised by the Department in its

[28] Interstate Power and Light Company's 2014 Electric Annual Automatic Adjustment Report, Exhibit H, Page 24.

[29] Department of Commerce 10/21/11 Comments - Review of the 2008-2009 Annual Automatic Adjustment Reports, Docket No. E999/AA-09-961 and the 2009-2010 Annual Automatic Adjustment Reports, Docket No. E999/AA-10-884, Chart 1, Page 28.

comments. Additionally, the Department noted that IPL was a large net purchaser because most of IPL's generation resources were higher cost generation facilities compared to the generation facilities in the MISO footprint. The concerns from the Department at the time were in relation to the generation sources of IPL, and ultimately with the impacts of that on energy costs. As IPL was purchasing energy on the market when the locational marginal price (LMP) indicated it was more economic than operating its own generation resources, the Department was concerned that the lower LMP would not always be the case, and that the Company should address its own generation resource cost. The Department requested that IPL provide in Reply Comments:

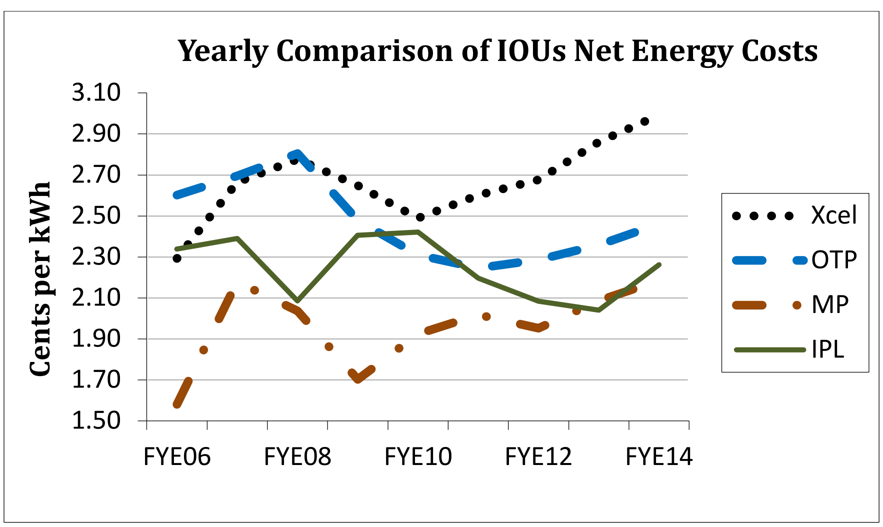
> Thus, the Department recommends that IPL explain in reply comments why IPL did not have reasonably economic generation resources in 2009 and 2010 compared to other utilities in the MISO footprint.

In its Response to Reply Comments, the Department responded to the information provided by the Company and recommended that:

> Rather than spending more time discussing what IPL should have done in the past, the Department recommends that IPL focus on working hard to incorporate the recommendations of the Department in our supplemental comments dated October 26, 2011 in IPL's current IRP in Docket No. E001/RP-08-673...

The Department has continued to track the energy costs of Minnesota utilities as part of the AAA review and has updated Figure 1 as illustrated below:

Figure 2 - Comparison of Energy Costs 2014



As the Department's primary concerns within the context of the AAA filings are energy costs, and not generation sources, the Department concludes that the overall performance of IPL's energy costs generally followed a more reasonable trend since the 2010 filing (however, IPL's net energy costs rose more sharply than for other utilities in FYE 2014).

In its FYE14 AAA filing, the Company stated:[30]

> If not already addressed in the 2012-2013 AAA proceeding, IPL repeats its request (made in the 2012-2013 AAA proceeding) that the Commission make a determination in this docket as to whether IPL is required to address is issue in future AAA filings.

The Department supports analyzing the quality and competitiveness of generation resources in the IRP process and consideration of the per-kWh cost of energy in the AAA process. Thus, the Department agrees that this reporting requirement need not continue.

IV. RAIL DELIVERIES ISSUES

Beginning in the fall of 2013 and continuing through the end of 2014, there were numerous reports in the popular press of rail transportation delays negatively affecting numerous industries, including the electric industry. A combination of increased congestion resulting from increasing volumes of oil being transported by rail, large agricultural harvests requiring rail transportation and inclement weather, particularly during the polar vortex, was cited as factors adding to the delays.

Minnesota's utilities rely on rail transportation to get coal delivered to its coal-fired generating plants, and were among those negatively impacted by these delays. Slow coal deliveries by rail resulted in some utilities limiting production at coal-fired generating plants in order to conserve coal. The Department attempted to investigate the rail delivery issues Minnesota's IOUs faced during FYE14, and assess whether the IOUs' planning and responses were reasonable.

A. OTTER TAIL

1. General Background

Otter Tail has three coal-fired generation plants: Big Stone Plant, Hoot Lake Plant, and Coyote Plant.

Otter Tail forecasts its coal needs with Strategist, the capacity-expansion model used in resource planning. Otter Tail models its system, including interaction with the energy market, to estimate how much power its coal plants will likely produce in the upcoming years. Otter Tail then converts that expected power output into a forecast of its coal needs using the heat content of the coal, the heat rates of its plants, minimum run requirements of its plants, and planned outage schedules. [31]

Otter Tail's coal procurement strategy is to secure a significant portion of a plant's coal needs under a forward contract to ensure supply and price certainty.[32] In the late summer,

[30] IPL 2014 AAA Report - Docket No. E999/AA-14-579, Exhibit H, Pages 24-25.
[31] Otter Tail response to DOC IR 21. Please note that all Otter Tail responses to discovery related to this section are provided in Attachment E6.
[32] Otter Tail response to DOC IR 21.

after the peak summer period has passed, coal needs are reassessed and purchases for the remainder of the year are adjusted accordingly. On January 1, 2014, Otter Tail had approximately 80-90 percent of its coal needs for 2014 under contract for Big Stone, and 80-90 percent of its 2015 needs under contract. On the same date, Otter Tail had 100 percent of its 2014 coal needs for Hoot Lake under contract, and 60-70 percent of its 2015 coal needs under contract.

Otter Tail's desired inventory at Big Stone Plant is 210,000 tons, or enough to last approximately 30 days. [33] Recently, Otter Tail has been targeting an inventory of 35-38 days' worth of coal during winter peak season at Big Stone Plant. Otter Tail's desired inventory at Hoot Lake Plant has been 33,750 tons of coal, or 20 days' worth of coal, and, recently, 25 days during the winter peak season. Otter Tail stated that maintaining sufficient coal stockpiles at Big Stone Plant and Hoot Lake Plant provides protection against the risk that the plants could be rendered unavailable for on-peak periods, long periods, or emergency periods (such as potential natural disasters that could reduce coal deliveries) due to lack of fuel. Otter Tail stated that the desired stockpile levels have been developed over time and have been adequate to meet the needs of the facilities.

Of Otter Tail's three coal plants, two, Big Stone Plant and Hoot Lake Plant, are served by BNSF railroad. The third, Coyote Plant, is a mine-mouth plant, meaning that the plant is located next to the mine from which the plant's coal is sourced, and coal is moved from the mine to the plant on a dedicated transportation system. Big Stone and Hoot Lake are captive rail customers (only one railroad, BNSF, is able to serve them).[34] Big Stone and Hoot Lake are served under BNSF tariff (rather than under long-term contracts) and are subject to the BNSF tariff for rail service to each plant, which Otter Tail provided in response to DOC IR 23.[35] In the same response, Otter Tail stated that tariff governance is very straightforward. The tariffs are specific to each plant, set minimum annual volumes, and have provisions related to freight charges, weight limits, loading and unloading of cars, billing, etc. Otter Tail stated that it communicates monthly to the BNSF the estimated monthly levels of coal delivery service for each plant. If the annual minimum level of coal deliveries is not met during the year, a higher transportation rate is applied to all deliveries during that year.[36]

2. Rail Delivery Issues

Otter Tail stated that beginning at the end of 2013 and continuing into 2014, BNSF was not able to meet coal delivery demand to Big Stone Plant.[37] Otter Tail included with its response to DOC IR 27 a letter to the Surface Transportation Board (STB), which regulates railroads, dated September 11, 2014 in which Otter Tail stated that during the preceding 12 months, BNSF had delivered only 80 percent of what Big Stone had forecasted.[38] Otter Tail stated that cycle times from the plant to the mine had increased and that BNSF had removed a

[33] Otter Tail response to DOC IR 28.
[34] Otter Tail response to DOC IR 22.
[35] Otter Tail response to DOC IR 23.
[36] Otter Tail response to DOC IR 22.
[37] Otter Tail response to DOC IR 26.
[38] Otter Tail response to DOC IR 27.

train set from service in response to congestion on its lines.[39] As a result of the longer cycle times and limited train availability, the coal stockpile at Big Stone Plant dropped below levels Otter Tail considers acceptable.[40]

In response to the low coal stockpile, Otter Tail, along with Big Stone Plant's other co-owners, decided to restrict plant output to conserve coal until inventory levels could be restored. Otter Tail stated in its response to DOC IR 26 that it implemented coal conservation efforts during two distinct periods: calendar year 2013 and the second half of 2014. Otter Tail provided a description of its conservation efforts during the second half of 2014, but did not describe its conservation efforts during calendar year 2013 beyond stating that the actions taken during 2013 were "similar" to the actions taken during 2014.[41]

Otter Tail stated that beginning June 19, 2014, during off-peak hours, OTP's share of Big Stone Plant's production capability between maximum and minimum output was offered into the MISO market at an artificially high price, which was intended to be slightly higher than the market clearing price, and thus caused Big Stone to not be selected/dispatched, and thus conserved coal.

Later, although Otter Tail does not say exactly when, Otter Tail and Big Stone Plant's other co-owners switched to a different coal conservation method in which a weekly energy target was imposed on each co-owner based on ownership share. Otter Tail stated that this conservation mechanism was intended to provide the same level of conservation as the previous mechanism, but also gave each owner the flexibility to offer the unit into the market at its maximum capability outside of the typical on-peak hours to help minimize replacement power costs, as long as it stayed within the weekly energy target.

Otter Tail stated that these coal conservation efforts ended at the end of 2014, and estimated that the incremental costs to ratepayers associated with replacement power were $0.8 to $1.0 million on a total system basis.[42]

In addition to these coal conservation measures, Otter Tail stated that its representatives have communicated frequently with BSNF, and sent a letter to the STB to express its dissatisfaction with the railroad.

3. Reasonableness Of Otter Tail's Actions

The Department's analysis of the reasonableness of Otter Tail's actions focuses on two primary questions. First, prior to the commencement of rail transportation issues, did Otter Tail act reasonably to protect ratepayers against the risk of *potential* rail delays? In other words, this question assesses *ex-ante*, whether Otter Tail took reasonable steps to insulate

[39] "Cycle time" refers to the amount of time a train set, which consists of 80-120 individual cars, takes to travel from a plant to a coal mine, get loaded with coal, travel back to the plant, and then unload its coal at the plant)
[40] Otter Tail response to DOC IR 26.
[41] Otter Tail response to DOC IR 26, part g.
[42] Otter Tail response to DOC IR 26, part e. Minnesota jurisdiction is approximately 50 percent of the Otter Tail system.

ratepayers from the effects of potential rail delays. Second, once the rail delivery issues started (*i.e.*, ex-post), was Otter Tail's response reasonable?

i. Ex-Ante Actions

Based on Otter Tail's responses to DOC's IRs, it seems that the primary method through which Otter Tail attempted to protect ratepayers from being harmed by potential rail delays was having coal stockpile targets of 30 days at Big Stone Plant (and 35-38 days during the winter peaks season), and 20 days at Hoot Lake Plant (25 days during winter peak season).

There are costs and benefits associated with having a larger or smaller coal stockpile. A larger stockpile can be harder to manage physically, and requires more working capital than a smaller inventory. The size of a stockpile is also limited by the amount of space available at a plant. However, a larger stockpile protects against the risk of rail delays causing inventories to drop to levels such that costly coal conservation measures are required. Otter Tail's targeted coal stockpiles are generally in line with the other utilities in the state, and thus appear to be reasonable.

One other ex-ante measure Otter Tail could have taken that might have provided some protection for ratepayers against potential harm resulting from rail transportation issues was to transport coal under a long-term contract, rather than under tariff. Rail transportation contracts can include provisions for damages if volume requirements are not met, whereas shippers requesting transportation under a railroad's tariff may have less recourse if its delivery requests are not accommodated. The Department requests that Otter Tail explain in reply comments why it chooses to transport its coal under tariff, rather than under long-term contracts.

In addition, the Department requests that Otter Tail discuss options under either tariffs or contracts for railroads to pay for a portion of the costs of replacement power due to unacceptable service.

Additionally, the Department notes that in Otter Tail's letter to the STB, referenced above, the Company stated that it has implemented coal conservation measures five times in the last eight years.[43] The Department requests that Otter Tail explain in reply comments whether it believes transporting its coal under contracts, rather than under tariff, would help alleviate some of these delivery issues.

ii. Ex-Post Actions

As described above, once rail delivery delays began to impact the coal stockpile at Big Stone, Otter Tail implemented coal conservation measures to ensure the continued operation of the plant. These measures involved setting an artificially high offer price for Big Stone's energy, which made the plant unlikely to be dispatched by MISO, but available for reliability and system stability events, and provided a price cap on energy for Otter Tail's ratepayers of the inflated offer price. If market prices rose above the inflated offer price, Big

[43] Otter Tail response to DOC IR 27, Attachment 1.

Stone would begin generating electricity, thus protecting ratepayers from high cost energy. The Department concludes that this approach was reasonable.

However, Otter Tail provided a detailed explanation only of the measures it took between June 19, 2014 and the end of 2014. Otter Tail did not explain what conservation measures it took during calendar year 2013. Additionally, Otter Tail did not provide enough detail regarding the incremental costs of replacement power to determine what portion of the $0.8 -$1.0 million is attributable to 2013 versus 2014. In this Docket, costs incurred during the period July 1, 2013 through June 30, 2014 are being reviewed. Thus, much of the costs incurred as result of coal conservation during calendar year 2014 will be reviewed in the next AAA Docket. The Department requests that Otter Tail provide in reply comments a detailed explanation of the coal conservation measures it took during calendar year 2013 and June 2014, and explain what portion of the $0.8 -$1.0 million in total associated incremental costs were incurred in 2013 and June 2014.

B. IPL

1. General Background

In 2013 and 2014, IPL operated five coal-fired generation plants, and had small ownership shares in three other coal-fired plants which are operated by Mid-American Energy.

IPL uses a forecasting model to develop projected annual generation levels for each unit in its system, including coal-fired units.[44] One of the model's outputs is the total amount of heat input needed to produce the projected generation level. IPL uses this information, combined with the heat content of its coal, to estimate the coal needs at each of its plants.

In DOC IR 21, the Department requested that IPL explain generally its coal procurement strategy. IPL did not provide a general response, but Attachment A to IPL's response to DOC IR 21 shows, as of January 1, 2014, the anticipated coal needs at each plant for 2014 and 2015, and the amount of coal IPL had under contract to purchase (which is separate from the transportation of the coal). As shown, as of January 1, 2014, IPL had between [TRADE SECRET DATA HAS BEEN EXCISED] of the coal needs at each plant under contract for 2014, and between [TRADE SECRET DATA HAS BEEN EXCISED] of the coal needs at each plant under contract for 2015.[45]

IPL generally tries to have coal stockpiles average between [TRADE SECRET DATA HAS BEEN EXCISED] days burn at its rail-delivered plants and [TRADE SECRET DATA HAS BEEN EXCISED] at its barge delivered plants.[46] IPL stated that its target inventory ranges are intended to consider the following factors:

1. Associated contractual minimum volume obligations under coal, rail, transload and barge agreements;
2. Whether a plant takes deliveries via rail or barge – inventories at barge-delivered plants need to be sufficient at

[44] IPL response to DOC IR 21. Please note that all IPL responses to discovery related to this section are provided in Attachment E7.
[45] IPL response to DOC IR 21.
[46] IPL response to DOC IR 28

the end of the barge season in fall to last through the winter until the river re-opens in spring;
3. Rail disruptions and flood and drought impacts on river traffic;
4. The length of time it takes for trains to travel between the mines and the plants (cycle times);
5. The railcar capacity available to supply coal to each plant; railcar capacity is often shared between plants and thus the inventory levels need to vary over time as trainsets are available for shipments to each plant;
6. Planned and unplanned maintenance outages at the plants, whether the generating unit(s) are unavailable due to maintenance work or the coal unloading equipment or rail tracks are unavailable due to maintenance work; inventories are often intentionally increased during maintenance outages because railcar capacity is not designed, nor needed, to simultaneously satisfy all plants' needs at peak generation times, generally summer months;
7. The capacity of each plant's inventory footprint; and
8. The variation in the quantities burned at each plant that can occur over time, in particular from year to year.[47]

IPL uses a combination of rail transportation and barge transportation to deliver coal to the plants it operates. **[TRADE SECRET DATA HAS BEEN EXCISED]** described above.[48]

2. Rail Delivery Issues

In its response to DOC IR 26, IPL stated that it implemented coal conservation measures only at its Lansing Plant, but not in response to rail transportation delays. Rather, the conservation measures were implemented in response to high rates of coal usage during the polar vortex of 2014, and the expected delay in the opening of the 2014 river navigation season due to weather conditions.[49] Lansing relies on barge transportation, which is not available during the winter months when the river is frozen. Thus, when the river is frozen, Lansing cannot receive coal, and IPL must ensure that the existing stockpile lasts until the river thaws and the river transportation system opens in the spring. The polar vortex in early 2014 created an expectation that the opening of the river transportation system in the spring of 2014 would be delayed. In response to the high rate of coal usage and the expectation of a delayed start to the river transportation system, IPL implemented coal conservation measures in March and April of 2014 to ensure that Lansing's coal stockpile would last until the river transportation season started. IPL used a varying dispatch adder between $5 and $10 per MWH to limit the consumption of coal during low marginal periods where the potential margin (between Lansing's generation cost and the energy market price) was less than the dispatch adder.

[47] IPL response to DOC IR 28.
[48] IPL response to DOC IR 22.
[49] IPL response to DOC IR 26.

During the 2014 river navigation season, flooding disrupted and delayed some coal shipments, and the season closed early in the fall due to cold weather. As a result, IPL was unable to build the stockpile at Lansing to the desired level, and, similar the spring, used dispatch adders during November and December to limit consumption of coal in order to ensure that the existing stockpile would last until the start of the 2015 river navigation system.

3. Reasonableness of IPL's Actions

i. Ex-Ante Actions

The trigger for IPL's coal issues was inclement weather, and there are few options available to prevent problems resulting from bad weather. Perhaps a larger coal stockpile at Lansing could have allowed IPL to handle the higher-than-expected usage of the Lansing plant during the polar vortex, as well as the late opening of the river transportation system. However, IPL's stockpile targets take into account the possibility of weather-related disruptions of barge transportation, and the polar vortex was an extreme event. Thus, the Department concludes, ex-ante, that IPL's actions with respect to its coal inventories were reasonable.

ii. Ex-Post Actions

The Department concludes that its response was reasonable. As described above, IPL limited production during periods with low LMPs, and IPL estimates the total incremental cost of this coal conservation measure to be $0.5 million on a total-company basis.

C. XCEL

1. General background:

Xcel operates three coal plants that serve Minnesota ratepayers: Sherco, Allen King, and Black Dog.

Xcel forecasts its coal needs with a production cost model that simulates the operations of the NSP electric power system on an hourly basis for the next several years.[50] This simulation produces an estimate of fuel needs for Xcel's fossil plants. This estimate serves as the basis for Xcel's coal procurement decisions. Generally, during the second quarter of the year, Xcel procures 85 to 100 percent of its coal needs for that year, 67 percent of its coal needs for the next year, and 33 percent of its coal needs for the year after that. When terms are attractive, Xcel may fill some or all of its anticipated coal needs for as many as five years. Additionally, Xcel continually evaluates and corrects fuel imbalances with spot sales and purchases.

Xcel's target coal inventory levels at the Sherburne County Plant (Sherco), Allen S. King (King), and Black Dog are **[TRADE SECRET DATA HAS BEEN EXCISED]**, respectively. In its response to DOC IR 28, Xcel stated:

[50] Xcel response to DOC IR 21. Please note that all Xcel responses to discovery related to this section are provided in Attachment E8.

> The desired coal inventory level for each of the plants is based on many factors but at its basic level is the amount of coal that is needed to be onsite in order to provide sufficient inventory that a facility can be available for operations in the event of a railroad or delivery disruption. That level is determined by analyzing the type and distance of the mine to the facility, the number of railcar sets in service, the historic cycle times, the number of units at a facility, and the carrying cost of inventory and then compares those factors to the replacement power costs in a given market should a unit run short of fuel. The analysis provides an optimal inventory level that should be maintained given the historical data with a margin for changed circumstances that may be unforeseen. A small plant with the ability to fuel switch to natural gas will carry less inventory than a large facility with a single fuel source at great distance.[51]

Based on the projected long-term coal requirements of its plants, Xcel negotiates multi-year coal transportation agreements with the railroads at volumes commensurate with the fuel requirements for the plants.[52] The terms of Xcel's existing long-term agreements generally provide for minimum and maximum annual volumes to be delivered, and contain liquidated damages clauses which provide for financial compensation in response to shortfalls in shipments caused either by Xcel or the railroad. Sherco is served by BNSF railroad. King and Black Dog are served by Union Pacific (UP).

2. Rail Delivery Issues

In its response to DOC IR 26, Xcel stated that delays to the Sherco plant, which is served by the BNSF railroad, began around October, 2013.[53] Xcel stated that the coal inventory at the Sherco plant dropped to a low level in the early part of 2014, but returned to normal optimal levels by February 2015.

In the same response, Xcel stated that delays to the Black Dog and King plants, which are served by the Union Pacific Railroad (UP), began in the first quarter of 2014 as a result of the extreme weather events during the winter of 2013-2014 (*i.e.*, the polar vortex). Xcel stated that inventories at those plants returned to normal early in the second quarter of 2014, almost a year sooner than for the plants served by BNSF, and have remained at optimal levels since then.

Xcel implemented coal conservation measures at the Sherco plant when inventories dropped to [TRADE SECRET DATA HAS BEEN EXCISED]. Xcel stated that no such measures were needed at the UP-served plants. Xcel used a cost adder in its energy offers from the Sherco plant, which allowed the plant to be backed down during periods with low replacement energy prices, but also made the plant available when energy prices were higher.[54] This coal conservation approach was used between March 14, 2014 and August

[51] Xcel response to DOC IR 28.
[52] Xcel response to DOC IR 22.
[53] Xcel response to DOC IR 26.
[54] Xcel response to DOC IR 26, part b.

6, 2014, and Xcel estimated that the incremental cost to ratepayers caused by this measure is $12.9 million.[55]

Xcel stated that it took a number of steps to minimize costs to ratepayers.[56] Xcel stated that the coal conservation measure itself was intended to minimize costs for ratepayers as it was intended to ensure that Sherco would have enough coal to operate during peak hours of the summer peaking season, when energy prices are generally at their highest during the year. Xcel also met frequently with BNSF management and provided testimony to the STB highlighting the importance of Sherco to regional electric reliability.[57]

Xcel did not take other direct steps, such as purchasing replacement energy with forward contracts.

3. REASONABLENESS OF XCEL'S ACTIONS

i. Ex-Ante Actions

As described above, Xcel's considers the possibility of rail delays in determining coal inventory levels at its plants and uses its inventory to protect ratepayers from negative impacts associated with rail transportation issues. The Department concludes that Xcel's decisions regarding its coal inventories are reasonable.

Additionally, Xcel's rail contracts include provisions for liquidated damages in the event the railroads do not meet their delivery obligations. [TRADE SECRET DATA HAS BEEN EXCISED]. In reply comments, the Department requests that Xcel explain whether and how the terms and conditions of its rail contracts in the future can be strengthened to avoid this issue.

ii. Ex-Post Actions

As described above, Xcel limited production at Sherco in order to ensure that Sherco would have enough coal to operate during peak hours of the summer peaking season. Xcel also met frequently with BNSF management and provided testimony to the STB highlighting the importance of Sherco to regional electric reliability.[58]

Xcel did not take other direct steps, such as purchasing replacement energy with forward contracts. However, because production at Sherco was limited only during off peak hours, the risks associated with high energy prices were mitigated.

Xcel stated that there was no way to perform a meaning qualitative or quantitative economic analysis for a short-term disruption in rail service, and that the only rail performance data available was actual deliveries and BNSF's forecast of future deliveries, which were overly optimistic.[59]

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[55] Xcel response to DOC IR 26, parts e and f.
[56] Xcel response to DOC IR 26, part g.
[57] Xcel response to DOC IR 26, part g.
[58] Xcel response to DOC IR 26, part g.
[59] Xcel response to DOC IR 26, part d.

D. MP

MP provided the Department with responses to information requests, not including attachments, on May 4, 2015, and the Department did not receive complete responses (with attachments) until May 7, 2015. MP's attachments to its IR responses included approximately 800 pages of documents. The Department was unable to complete its review and analysis of MP's IR responses in time to include it in this report. The Department will review MP's IR responses and file its analysis in DOC's response comments to the IOUs' reply comments.

V. TOTAL FUEL COST REVIEW

A. OVERVIEW

Table 2 summarizes the electric utilities' fuel-cost recovery during FYE14.[60] 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.

Table 2:
Summary of Automatic Fuel Adjustments FYE14

Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)	(%)
DEA	$147,088,516	$149,582,605	($2,494,089)	(1.67%)
Interstate Electric	$19,912,643	$19,229,800	($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 Electric	*$941,003,558*	*$926,441,508*	*$14,165,747*	*1.53%*

To review the electric utilities' calculations of automatic adjustment charges, the Department compared actual costs of fuel purchased during the year to the fuel costs recovered through automatic adjustments.[61]

The Department recognizes that utilities will normally experience small over-recoveries and under-recoveries. In the past, most fuel-cost variations have been caused by fluctuations in weather and by price volatility in the wholesale electric market. Higher-than-anticipated energy demand forces a utility to either generate or purchase additional power. As a result, marginal costs increase as demand increases, typically leading to under-recovery of fuel costs. The reverse is also true: lower-than-expected energy demand can cause fuel costs to

[60] Supporting spreadsheets for FYE14 data with Department's calculations are provided in Attachment E9 (Dakota), Attachment E10 (IPL), Attachment E11 (MP), Attachment E12 (OTP) and Attachment E13 (Xcel Electric).
[61] The Department notes that DEA, OTP and Xcel Electric all have true-up mechanisms, so they are not financially impacted materially by the over/under recovery.

fall and lead to over-recovery of fuel costs. The "2 and 3 lag-month" associated with the calculation of most utilities' energy-cost adjustments also leads to unexpected variations, since fuel costs incurred in a given month are recovered in later months.[62] Generator outages and a variety of other supply-side factors can also cause variations in fuel costs.

As indicated above, the Department notes that the reporting period includes the ninth full year of costs incurred in the MISO Day 2 Market, which began on April 1, 2005. This issue is discussed further below.

B. DAKOTA ELECTRIC ASSOCIATION

DEA serves about 103,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment E9 shows that DEA's resource adjustment includes $149,582,605 or $79.55/MWh in fuel costs, which includes generation capacity and transmission costs from its supplier during the reporting period.[63]

Regulated utilities normally recover through their automatic adjustments only changes from the amounts set in a rate case of costs of fuel and energy from purchased power agreements; changes in capacity costs are typically not reflected in fuel adjustment clauses. As an electric cooperative providing only distribution service, however, Dakota requires special consideration because it recovers variations in purchased capacity costs as well as energy costs through the fuel adjustment clause. Ordinarily, the inclusion of these costs increases Dakota's monthly over- and under-recoveries, since purchased capacity costs are not as closely linked to variations in sales as are energy costs. Changes in sales can result in a significant gap between the utility's actual purchased capacity costs per kWh and the purchased capacity costs per kWh built into its base rates. To account for potential discrepancies between its actual and recovered costs through its automatic adjustment, Dakota calculates and applies an annual fuel-cost true-up factor based on these discrepancies.

C. INTERSTATE ELECTRIC

Interstate serves approximately 44,000 electric customers in Minnesota, primarily along the southern edge of Minnesota. Interstate's FYE14, fuel costs were $22.62/MWh and $19,912,509[64] in total for its Minnesota operations in FYE14, an increase of $2,287,967 compared to the $17,624,542 fuel costs in FYE13. On a per-MWh basis, fuel costs in FYE14 represent an 11 percent increase over the $20.4/MWh experienced by IPL in FYE13, and are probably attributable to the extreme weather events brought about by polar vortex conditions over the winter months of 2013-2014.

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[62] During the reporting period, Interstate Electric, MP, and OTP used a moving-average process to calculate their energy-cost adjustments. The average costs that these utilities used for their adjustments were calculated using costs that were incurred two and three months prior to the month in which such costs were recovered. As noted above, Xcel Electric did not use this method during the reporting period.

[63] Subject to Commission approval, Minnesota Rule 7825.2600 allows a utility that purchases at least 75 percent of its annual energy requirements to include capacity costs in its energy adjustment. Dakota does not have its own generation. Dakota purchased all its energy needs from its power supplier, Great River Energy..

[64] Docket No. E999/AA-14-579 Exhibit C, Page 4.

During FYE14, Interstate recovered $19,229,400 in fuel cost and experienced $19,912,509 in actual fuel costs for an under-recovery of 3.43 percent. Interstate had 4 months in which over- and under-recoveries were in excess of 15 percent. For comparison, in FYE13 Interstate had 7 months of over- and under-recovery above 15 percent, with 9 months in FYE12 and 5 months in FYE11. In FYE14 Interstate experienced an under-recovery of 3.43 percent after experiencing 3.29 percent over-recovery in FYE13 and a 6.14 percent under-recovery in FYE12.

D. MINNESOTA POWER

Minnesota Power serves about 144,000 electric customers in northeastern Minnesota. MP's fuel costs in the FCA were $195,704,305 for FYE14.[65] As shown in Table 2 above, MP under-recovered its fuel costs by $2.3 million in FYE14, or approximately 1.16 percent of its actual costs. By comparison, in FYE13, MP's actual fuel costs in the FCA were $186,736,616, and MP over-recovered by approximately $0.6 million, or 0.32 percent. In FYE12, MP's actual fuel costs in the FCA were $172,309,289, and MP under-recovered by $4.0 million, or 2.32 percent. Compared to the $20.9/MWh level of fuel costs in FYE13, MP's costs in FYE14 of $21.85/MWh were 5 percent higher.

The Department notes that MP's level of under/over-recovery varies from month to month. In FYE14, MP's monthly under/over-recoveries ranged from a $2.9 million under-recovery in September 2013, to a $2.9 million over-recovery in February 2014.

E. OTTER TAIL POWER COMPANY

Otter Tail serves more than 59,000 Minnesota electric customers, primarily in western Minnesota. During the reporting period, OTP's total fuel costs in the FCA were $55,705,076 or $24.61/MWh for OTP's Minnesota operations in FYE14.[66] This level is 4 percent higher than the $23.6/MWh cost in FYE13.

OTP's total fuel costs in the FCA were $50,027,393 for FYE13, resulting in an approximate increase from FYE13 to FYE14 of $5.7 million. The Department noted that the $5.7 million increase appears to be due to the polar vortexes and increased MISO Day 2 charges as discussed below.

During FYE14, Otter Tail experienced 4 months of over- or under-recovery greater than 15 percent. However Otter Tail only incurred a 3.29% under recovery on FYE14 as a whole.

[65] Source: Attachment E11.
[66] Source: Attachment E12.

F. XCEL ELECTRIC

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had fuel costs in its FCA of $926,441,508 for FYE14, amounting to[67] $29.21/MWh. This level is 2 percent higher than the $28.6/MWh cost in FYE13. (Note that this relatively low increase in per-unit costs for FYE14 reflects the fact that costs in FYE13 included replacement power costs for Sherco 3, as discussed in Docket No. E999/AA-13-599, including pages 17-23 for the Department's September 19, 2014 Report and pages 11-13 of the Department's December 31, 2014 Response comments.)

Xcel Electric is the only electric utility to use a forecasted FCA method.[68] Under this method Xcel Electric bases its monthly FCA on its one-month projection of fuel and purchased power costs. Xcel Electric uses this method in lieu of a forecast based on the average of the most recent two months of known costs as specified by Minnesota Rules. The Commission also allowed Xcel Electric to make an additional adjustment to its forecasted FCA to true-up any over- or under-recoveries of costs that it experienced two months prior to the month in which it applies a new FCA. As a result, unlike electric utilities that calculate their FCA using the method required in the Minnesota rules, Xcel Electric is expected to be better able to reflect current FCA costs in rates closer to the time when these costs are incurred.[69] Moreover, it is expected that Xcel Electric's recovery of costs, in general, will be more closely aligned with costs incurred, with less deviation in cost recovery compared to cost incurrence. While Xcel's monthly true-up should ensure that Xcel will recover costs closer to the time when those costs are incurred, it may also result in significant deviations in cost recovery in the month the true-up is implemented and distort information about current fuel costs.

VI. EFFECTS OF MISO DAY 1 ON MINNESOTA RATEPAYERS

On March 28, 2002, the Commission approved petitions requesting the transfer of functional control of certain transmission facilities to MISO from the following IOUs:

- Xcel Electric, Docket No. E002/M-00-257, Order issued May 9, 2002;
- Interstate Electric, Docket No. E001/PA-01-1505, Order issued May 9, 2002;
- Minnesota Power, Docket No. E015/PA-01-539, Order issued April 26, 2002; and,
- Otter Tail Power, Docket No. E017/PA-01-1391, Order issued May 9, 2002.

These four Minnesota electric investor-owned utility companies were required to provide the information below as part of their AAA report. The Department summarizes the companies' responses to the seven ordering paragraphs as discussed below.

[67] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part E, Section 5, Schedule 1, Page 3 of 5, Line 37.
[68] See the Commission's May 4, 2012 Order in Docket No. E002/M-11-452.
[69] Under the method in the Commission's rules, a utility's cost recovery position may be positive or negative depending on the 12-month time frame selected over which cost recoveries are aggregated.

A. *THE SCHEDULE 10 ADMINISTRATIVE CHARGES PAID TO MISO UNDER THE MISO TARIFF.*

The four Minnesota Electric Utilities provided the following administrative charges, referred to as "Schedule 10 costs," billed by MISO for the period July 2013 through June 2014:

Table 3: MISO Schedule 10 Costs for July 2013 through June 2014

	Total Company	Estimated MN Jurisdiction
Xcel Electric	$9,818,765[70]	$7,313,779
Interstate Power	$2,423,899[71]	$141,313
Minnesota Power	$1,748,379[72]	$1,356,218
Otter Tail Power	$688,278[73]	$329,220
Total	$14,679,321	$9,140,530[74]

The total amount charged to these companies for MISO Schedule 10 costs decreased by $1,366,330 or 8.52 percent from the previous reporting period. The total estimated Minnesota jurisdictional amount resulted in a decrease of $827,963 or an 8.31 percent decrease from the previous reporting period. All IOU's MISO Schedule 10 costs decreased from the previous reporting period. Minnesota Power indicated that the decrease is mainly attributable to decrease in average rate for demand MWh and average rate for energy MWh.

The Department continues to monitor MISO Schedule 10 costs and expects the four Minnesota utilities in MISO to show benefits related to these costs in their rate cases before receiving cost recovery. This recovery and analysis occurs in rate-case proceedings, and has occurred in Xcel Electric's, Interstate Electric's, OTP's and MP's rate cases. Thus, these costs are not charged through the FCA; rather, they are charged through base rates.

The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional MISO Schedule 10 costs, together with the allocation factor used, and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require the utilities to provide information to support any increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs.

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[70] MISO Schedule 10 costs paid by NSP-Xcel consist mostly of Minnesota costs, with some costs for Wisconsin, North Dakota and South Dakota. The Department estimated the Minnesota jurisdiction percentage of 74.49% jurisdictional allocator from Xcel's most recent rate case.
[71] MISO Schedule 10 costs paid by Alliant Energy for IPL for the AAA period. The Department assumed IPL's Minnesota retail jurisdictional percentage at 5.83%.
[72] MISO Schedule 10 costs paid by MP for the AAA period with an average Minnesota retail jurisdictional percentage of 77.57%.
[73] MISO Schedule 10 costs paid by OTP for the AAA period. The OTP estimated Minnesota retail jurisdictional percentage is 47.83%.
[74] Xcel AAA initial filing's Attachment I, Section 1-7, Pg. 2 of 9, OTP AAA initial filing's Part D Section 5, Attachment A, MP AAA initial filing's Attachment No. 6 and IPL's AAA initial filing's Attachment H provide the Minnesota Jurisdictional MISO Schedule 10 costs.

B. ANY AMOUNT OF MISO ADMINISTRATIVE CHARGES DEFFERED BY MISO FOR LATER RECOVERY.

This reporting requirement pertains to MISO administrative charges (Schedule 10 costs) that were deferred as regulatory assets for later recovery. At the Department's request, the electric utilities provided the following comprehensive answer to describe MISO's deferred Schedule 10 costs:

> "Transmission Start-up Costs" are MISO operating costs incurred prior to initial start-up that were deferred in accordance with a FERC order. These costs are being recovered over a six-year period from MISO's customers through monthly charges under Schedule 10 of the MISO tariff. The "$0.15 per MWh Rate Cap" asset is for ongoing costs incurred but not recovered under Schedule 10 due to the $0.15 per MWh rate cap in place during the first six years of commercial operations. The rate cap ended on February 1, 2008. The "Current Schedule 10" rates based on forecasted billing units and actual costs for the month are included in subsequent months' rate calculations. These costs are classified as deferred regulatory assets, and will be recovered in a subsequent period.

In a March 26, 2003 compliance filing in response to the FERC's Order accepting a contested partial settlement in Dockets ER02-111 and ER02-652, MISO proposed changes to Schedule 10 to reflect deferral of $25 million of current expenditures that would have been recovered under Schedule 10 in 2003, but which were deferred until February 1, 2008, to be recovered over a five-year period. There are no additional deferrals beyond the $25 million.

During 2003 and 2004, MISO made payments to Grid America, Ameren and Illinois Power. These payments by MISO, net of the exit fees, totaled $40,319,000 and are being amortized over a 10-year period. Amortization of these costs ended as of September 30, 2013

The Department included the actual MISO Schedule 10 costs paid by utilities for July 2013 to June 2014 in Table 3 above.

C. EACH INSTANCE WHERE MISO DIRECTED COMPANIES TO CURTAIL THEIR OWN GENERATION, FOR RELIABILITY REASONS, THAT RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO RETAIL CUSTOMERS OF MINNESOTA.

All four utilities indicated that no such instances occurred during the reporting period July 2013 through June 2014.

D. *EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF DELIVERY OF A FIRM PURCHASE POWER SUPPLY THAT SUBSEQUENTLY RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO THE COMPANIES' RETAIL CUSTOMERS IN MINNESOTA.*

All four utilities indicated that no such instances occurred during the reporting period July 2013 through June 2014.

E. *CHANGES TO MISO TARIFFS THAT MAY ULTIMATELY AFFECT THE RATES OF RETAIL CUSTOMERS TO MINNESOTA, AND ON COMPANIES' EFFORTS TO MINIMIZE MISO TRANSMISSION SERVICE COSTS.*

The Companies provided various answers in their MISO Day 1 compliance filings on the effect on retail rates in Minnesota of changes to MISO's tariffs. Specifically:

- During the period July 1, 2013 to June 30, 2014, MISO submitted significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission Energy and Operating Reserve Markets Tariff (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect rates of retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available by month at the MISO web site (www.midwestiso.org) at the "FERC Filings and Orders" quick link. Xcel Electric's Part D Section 8 in their AAA filing summarizes the MISO filings and other FERC proceedings with the potential for more substantial financial impact on the Company (and thus the rates charged to retail electric customers in Minnesota), and the Company's efforts to minimize MISO costs through its interventions and comments filed at FERC.

- Utilities indicated that they have participated in several ongoing efforts to minimize MISO transmission service cost. They stated that their representatives participated in the MISO Transmission Owners Committee and the Transmission Owners Tariff Working Group, which make decisions on certain rate and revenue distribution changes pursuant to the MISO Agreement. They also stated that they have closely monitored the Market Sub-Committee and OATT Business Practices efforts. Finally, they stated that they have been actively involved in the ongoing Regional Expansion and Cost Benefit Task Force (RECB). They have begun to see cost allocations under the previously approved tariff schedules. MISO, with the support of Transmission

Owners, filed changes to the RECB cost allocation process proposing that costs associated with Multi Value Projects (MVPs) be allocated across the entire MISO footprint rather than to nearby pricing zones. FERC did approve this filing on December 16, 2010. Projects designated as MVPs are large scale transmission builds required to bring mandated energy (such as renewables) to load. The general consensus is that all loads will benefit from this type of build; therefore, all should share in the cost. MISO has approved the first MVP for cost allocation, "The Michigan Thumb Project," and has given preliminary approval for the second MVP Project, "CAPX 2020 Brookings to Twin Cities Project." Utilities have begun to see charges associated with these projects in 2012.

- MISO has included Schedules 16 and 17 in its Open Access Transmission and Energy Markets Tariff. These schedules are related to MISO's implementation and administrative costs of the MISO energy market. Schedule 16 recovers costs associated with Financial Transmission Rights and Schedule 17 recovers costs associated with the day-ahead and real-time markets. Utilities noted that Schedule 16 and 17 costs have trended downward with expanded MISO membership.

F. AN ANNUAL ANALYSIS OF HOW THE TRANSFER OF OPERATIONAL CONTROL TO THE MISO HAS AFFECTED COMPANIES' OVERALL TRANSMISSION COSTS AND REVENUES AND OVERALL ENERGY COSTS FOR RETAIL CUSTOMERS, INCLUDING:

i. an analysis of how MISO membership has affected Companies' ability to use their own generation sources when they are the least-cost power source; and
ii. Companies' ability to access low-cost power on the wholesale market for their retail customers.

Generally the utilities agreed that the transfer of operational control of transmission to MISO has not had a significant impact on overall transmission costs. The utilities have noted some decreases in transmission revenues; however reduced transmission rates have benefited utilities that need to make energy purchases to serve native load customers. The utilities note that an increase in costs has occurred due to costs charged under Schedule 10, MISO's administrative charges (see discussion in section E.4.a above), but a decrease in costs has occurred due to the elimination of transmission rate "pancaking" and elimination of the MAPP or MAIN fee, which likely results in an slight overall net increase in cost.

The utilities generally agreed that they continue to make use of the wholesale power market to provide low-cost energy for their customers. Utilities also indicated there have been times when they have been able to buy power below base load generation costs to the benefit of ratepayers.

Xcel Electric provided the following response in regard to how MISO has affected Xcel Electric's ability to use its own generation sources when these are least-cost power sources:

> In summary, NSP makes Company-owned and purchased network resources available to the regional dispatch optimization. NSP uses proprietary resource trading methods to ensure the least cost resources remain available for native supply, while ensuring that competitive regional supply alternatives have the opportunity to clear when they can provide energy at lower costs.
>
> In general, operation of the Day 2 market and ASM market has not negatively affected the Company's ability to use its own resources (Company-owned generation or bilateral purchased power) when those native resources are the least cost power resource. In particular, the Day 2 market has facilitated the integration of wind energy resources in the regional dispatch much more efficiently than would be the case if NSP system operations had continued on a stand-alone basis.
>
> The Company continues to experience the benefits and efficiencies of the MISO Day 2 Market since its initial operation on April 2005 that enhanced NSP's ability to access low-cost power. On a qualitative [note], NSP['s] experience with the regional generation dispatch market operated by MISO shows benefits related to integration of wind generation resources in the regional economic dispatch. Absent of the MISO provided access to generation on a large regional basis, NSP would experience more disruptive local dispatch requirements, thereby increasing costs for our customers.

G. CONCLUSIONS REGARDING MISO DAY 1

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

The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

VII. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

This AAA report is based on eight full years of data under the MISO Day 2 energy market. Due to the significance of the MISO Day 2 markets on Minnesota ratepayers, the DOC dedicates this section to discussing the effects of this market on the way utilities procure energy and the way these costs are reflected in rates.

MISO's Day 2 energy market[75] both did and did not change the way utilities provide service to customers. On one hand, as noted by the Commission in its December 20, 2006 Order *Establishing Accounting Treatment for MISO Day 2 Costs* (Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406), MISO's tariff re-characterized the way utilities provide electricity for the customers they are obligated to serve (native load customers[76]), including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any surplus or deficit from or to neighboring utilities. In contrast, under MISO's tariff, utilities sell all power from their electric generation and other resources into the wholesale market, and purchase power back from the market to provide electric service for their ratepayers.

On the other hand, the Commission required utilities to continue to use the lowest cost resources to serve customers, and this fundamental aspect of service did not change, due to MISO's order of dispatching resources into the wholesale market. Moreover, the Commission required a significant amount of oversight of the activity of utilities in the MISO Day 2 market. This oversight has included investigations, reports and various efforts to ascertain whether the utilities are, in practice, acting in the best interests of their customers in the Day 2 market. The following discusses more of the development of MISO Day 2.

On April 1, 2005, MISO began operation of the Day 2 Energy Market, pursuant to its Transmission Energy Market Tariff (TEMT). In technical terms, MISO initiated regional security constrained economic dispatch with day-ahead and real-time energy markets (described below). The goal is to dispatch generation resources in the most efficient manner in the region, given transmission constraints. Under the Day 2 tariffs, all MISO participants that own or operate generation are required to submit offers for their generation resources (either owned generation or purchases) that are "Network Resources" of the market participant. At the same time, each MISO load serving entity (LSE) participant must bid their load requirements into the market. (Since utilities are market participants with generation and are also LSEs, utilities participate with both bids and offers.) After receiving the generation offers and load bids, MISO determines the optimal supply of resources that reflects delivery constraints on the transmission grid. MISO "clears" both the day-ahead and real-time markets over its entire footprint, based on participants' bids and offers and the limitations of the transmission system, with the optimized cost of supply.

The Commission issued the following three Orders addressing the utilities' petitions for cost recovery of MISO Day 2 costs.

[75] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).
[76] TEMT § 1.208 (issued May 27, 2005).

First, because the Commission had not yet had sufficient opportunity to evaluate the parties' arguments, on April 7, 2005, the Commission provided temporary relief by permitting the parties to recover Day 2 costs through the FCA on an interim basis subject to refund.[77]

Second, in its December 21, 2005 Order, after further analysis, the Commission concluded that only certain costs should be recovered through the FCA. In particular, the Commission concluded that the costs of administering the MISO Day 2 Market listed in Schedule 16 and 17 were insufficiently related to energy or the types of costs previously recovered through the FCA to warrant FCA recovery. The Commission ordered the utilities to refund the balance to ratepayers.[78]

In addition the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations. Finally, the Commission proposed an investigation into the best method for assuring low-cost electricity in Minnesota.[79] These basic principles are still in place.

Third, on reconsideration, Commission granted all parties additional time to address the requirement that utilities immediately implement a refund to their customers. By Order dated February 24, 2006, the Commission suspended the immediate refund obligation and restored the utilities' authorization to continue recovering all MISO Day 2 costs through the fuel clause. While this recovery remained as interim, subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring the MISO Day 2 administrative costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[80]

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[81] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize utilities to recover most Day 2 costs via their fuel clauses. In support of the proposal, the utilities agreed to make certain commitments, described further below.

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77 Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005).
78 Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation (December 21, 2005 Order).
79 December 21, 2005 Order at Ordering Paragraph 10.
80 Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings at 7-8.
81 The Joint Report reflected the views of all parties except for what is now known as the Office of Attorney General, Anti-Trust and Utilities Division.

On December 20, 2006, the Commission issued its Order approving MISO Day 2 costs through the FCA, except for Schedule 16 and 17 costs. Schedule 16 and 17 costs were determined to be base rate costs recoverable in the context of a rate case, not energy costs recoverable through the FCA. The Commission's Order addressed conditions for virtual transactions, accounting practices, customer protections, wholesale revenues, and investigation by the Commission to ensure low-cost electricity in Minnesota. Finally, the Commission's Order required utilities to provide to the DOC several additional reporting requirements in their monthly FCA reports and AAA reports (ordering paragraph 7).

The DOC's analysis below is a limited review of MISO Day 2 overall charges, specific MISO Day 2 charges based on a fluctuation analysis, related allocations to customers, and asset-based margin sharing.

B. OVERALL EFFECTS OF MISO DAY 2 MARKET ON UTILITIES AND THEIR CUSTOMERS

According to MISO's tariff, the Day 2 Market encompasses both the "Day-Ahead Market" and the "Real-Time Market." To participate in the Day-Ahead Market, utilities forecast customers' demand for electricity the next day, including the magnitude and geographical location of the demand. The utilities also designate the generators (network resources) they will make available to meet the total system's needs, and the terms under which each generator would provide electricity to the market if selected (dispatched). MISO uses information from all participants and creates a plan to match supply with demand, consistent with the constraints of the generators and the transmission grid. The following day – the Real-Time Market – MISO implements its plans, adjusted to accommodate changes arising from, for example, unanticipated hot weather or a mechanical failure at a power plant.

In theory, the Day 2 Market enables MISO to dispatch generators with lower operating costs to meet the aggregate demand of all customers without regard to which utility owns a given generator or transmission line, or which utility has an obligation to serve a given customer. This process determines the marginal price of electricity – that is, the price of generating the last unit of power required to meet the combined needs of all customers, when all lower cost sources of power are already in use.

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the transmission grid. As noted in AAA filings since at least FYE2007, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

The DOC discusses our review and audit of MISO Day 2 charges in the next section, including recommendations regarding overall cost review and allocation of MISO Day 2 charges between retail and asset-based wholesale customers.

C. OVERALL REVIEW OF MISO DAY 2 CHARGES

This section discusses our overall review of MISO Day 2 charges and allocations between retail customers and the wholesale sector for the following areas:

- Day-Ahead and Real-Time Energy;
- Congestion Costs and Financial Transmission Rights (FTRs);
- Energy Losses;
- Virtual Energy/Non-Asset Based Transactions;
- Revenue Sufficiency Guarantee (RSG) Costs and Make Whole Payments;
- Revenue Neutrality Uplift (RNU) Charges;
- Auction Revenue Rights (ARR); and
- Grandfathered Charges.

The DOC's audit of MISO Day 2 charges started with the "MISO Day 2 Spreadsheet of Charges" as originally developed in the MISO Day 2 stakeholder process and as ordered by the Commission in its Final MISO Day 2 Order, Ordering Paragraph 7, part g. This MISO Day 2 spreadsheet of charges and additional support for MISO Day 2 net cost allocations, especially between retail and wholesale, was updated in the Commission's February 6, 2008 Order for the 2006 AAA, in Ordering Paragraphs 21 to 24.

1. Review of Xcel Electric's MISO Day 2 Charges

Xcel Electric allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale/intersystem, and non-asset-based wholesale/intersystem. The Company's invoices from MISO are broken out into Xcel Electric's two asset owners: NSPP (generator asset owner) and NSPT (Xcel's trading owner which handles non-asset-based transactions). Since Xcel Electric has two asset owners set up with MISO, the MISO bill for a given month can be separated between NSPP and NSPT using the MISO daily settlements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part J Section 5 on Schedule 7 page 13 of 13 of Xcel's Electric's FYE14 AAA Report. The Department notes that amounts totals reflected on Part J Section 5 Schedule 7 are at the total Company level.

A summary of Xcel Electric's total MISO Day 2 charges assigned to retail customers on a total company basis for current and prior AAA reporting periods is provided below:

Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014
Net Costs	$226.2	$191.5	$195.9	$196.6	$200.5[82]	$222.9[83]

The Department notes that Xcel Electric's MISO Day 2 net costs assigned to retail ratepayers have generally been increasing each year since the Great Recession, with net costs being

[82] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[83] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.

highest during the 2008-2009 period, when energy prices peaked and MISO's locational marginal price (LMP) was higher.

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE14 and identified several issues that warranted information requests. These issues, along with the Company's response to our questions, are discussed below.

a) #1a Day-Ahead Asset Energy

Noting that the amount of Day Ahead Asset Energy charges (revenues) assigned to retail ratepayers increased by 15 percent from $277,669,836 in FYE13 to $319,213,148 in FYE14, the Department asked Xcel Electric to explain this increase in DOC Information Request No. 36. Xcel Electric replied that:

> The Day Ahead Asset Energy charges (revenues) assigned to retail year over year increase is primarily driven by a spike in natural gas prices during the period December 2013 through March 2014 when gas prices more than doubled. During this timeframe, cold temperatures caused a large increase in electricity demand resulting in high natural gas prices exacerbated by gas curtailments. This led to high unit offer prices and a sharp rise in energy prices. NSP load zone prices increased 56 percent to $46.13 per MWh compared to the prior winter/spring period.

The Department appreciates Xcel Electric's response to our question and agrees that higher natural gas prices, colder temperatures, increased demand, and gas curtailments contributed to higher Day-Ahead Asset Energy charges. As a result, the Department concludes that the Company has reasonably explained its year-over-year increase in Day-Ahead Asset Energy charges.

b) #1b Day-Ahead Congestion

The Department noted that Day-Ahead Congestion charges more than doubled from $47,122,243 in FYE13 to $98,620,207 in FYE14 even though the total number of Day-Ahead Asset Energy MWh's decreased from 7,329,064 in FYE 13 to 6,600,957 in FYE 14. The Department asked Xcel Electric to explain this increase in DOC Information Request no. 39. Xcel replied that:

> There was a significant increase in marginal congestion costs during the winter/spring period of 2014 compared to the prior year due to transmission constraints. This was driven by high load related to cold weather combined with generation and transmission outages.
>
> The MWh referenced above are net generation and load transactions. On an absolute gross basis there were 82 million MWh vs. 81 million MWh transacted in the Day Ahead Asset

> Energy charge type for an increase of 1 million MWh year over year.

Based on the above, The Department concludes that the Company has reasonably explained its year-over-year increase in Day-Ahead Congestion charges.

c) #1c Day-Ahead Loss

The Department noted that total Day-Ahead Loss charges increased from $34,766,387 in FYE13 to $55,650,078 in FYE14, even though the total number of Day-Ahead Asset Energy megawatt-hours (MWh's) decreased from 7,329,064 in FYE13 to 6,600,957 in FYE14. As a result, the Department asked Xcel Electric to explain this increase in DOC Information Request No. 37. Xcel Electric replied that:

> There was a significant increase in marginal loss costs during the winter period of 2014 compared to the prior year. The increase was the result of changes in system load and generation patterns driven by high load related to cold weather combined with generation and transmission outages.
>
> MWh presented in the question are net generation and load transactions. On an absolute gross basis there were 82 million MWh vs. 81 million MWh transacted in the Day Ahead Asset Energy charge type for an increase of 1 million MWh year over year.

Based on the above, The Department concludes that the Company has reasonably explained its year-over-year increase in Day-Ahead Loss charges.

d) #22a Real-Time Non Asset Energy

The Department noted that the Real-Time Non Asset Energy charges (revenues) assigned to retail increased from ($210,272) in FYE13 to $1,444,148 in FYE14. As a result, the Department asked Xcel Electric to explain this increase in DOC Information Request No. 35. Xcel replied that:

> The Real Time Non Asset Energy charges (revenues) assigned to retail year over year change is primarily driven by real-time curtailments of day-ahead physical schedules sold into the market which increased year over year, FYE13 to FYE14. Day-ahead schedules are initially settled in the Day Ahead Non Asset Energy charge type. When day-ahead physical schedules are curtailed in real-time, market participants are required to buy back the curtailed volume in the Real Time Non Asset Energy charge type.

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

e) #33 Day-Ahead Schedule 24 Allocation Amount and #34 Real-Time Schedule 24 Allocation Amount

In DOC Information Request No. 38-1, the Department asked Xcel Electric to explain why retail and asset-based wholesale was assigned Day-Ahead Schedule 24 Allocation Amount charges of $1,065,827 and $15,626, respectively, in FYE14. Xcel Electric replied that:

> The retail amount for Day Ahead Schedule 24 Allocation was based on the full Day Ahead Scheduled volume. This volume, multiplied by the MISO Schedule 24 rate per MWh, determines the total Day Ahead Schedule 24 amount for each month that is charged to retail. For each monthly period, a portion of the Day Ahead volume is allocated to asset-based wholesale. The volume assigned to asset-based wholesale is a subset of the overall retail volume. That volume multiplied by the MISO Schedule 24 rate per MWh results in the amount of Day Ahead Schedule 24 allocation to asset-based wholesale. Therefore, the asset-based amount will be smaller than the retail amount.

Based on the above, the Department understands that Day-Ahead Schedule 24 Allocation Amount charges are assigned to retail and asset-based wholesale on an MWh basis. The Department recommends that Xcel Electric confirm our understanding in reply comments.

In DOC Information Request No. 38-2, the Department asked Xcel Electric to explain why retail was assigned Real-Time Schedule 24 Allocation Amount costs of $76,813 while asset-based wholesale was assigned revenues of ($1,525,437) in FYE14. Xcel Electric replied that:

> The Real Time Schedule 24 Allocation line item is net of two different charge types. The two charge types are RT Schedule 24 Distribution and RT Schedule 24 Allocation. The RT Schedule 24 Distribution charge type represents the reimbursement of the Company's O&M expenses related to the Company's functions in the Energy and Operating Reserve Market. These credits totaling ($1.5 million) are not allocated to retail. They are reclassified to Transmission Revenue for inclusion in that recovery mechanism. The RT Schedule 24 Allocation charge type is the mechanism that funds the Schedule 24 distribution back to Local Balancing Authorities. It is measured by the gross volume of MW transacted in real-time. This volume is allocated to retail with a smaller portion allocated to asset-based wholesale. These volumes are then multiplied by the MISO Schedule 24 rate and booked to their respective classifications.

Based on Xcel Electric's response, the Department understands that Real-Time Schedule 24 Allocation charges are assigned to retail and asset-based wholesale on an MWh basis. In contrast, Real-Time Schedule 24 Distribution charges (revenues) are only assigned to asset-based wholesale where they are then reclassified to transmission revenues.

The Department recommends that Xcel Electric fully explain the following in reply comments:

- why Real-Time Schedule 24 Distribution charges (revenues) are only assigned to asset-based wholesale,
- why Real-Time Schedule 24 Distribution charges (revenues) are reclassified from asset-based wholesale to transmission revenues, and
- which specific recovery mechanism Xcel Electric was referring to in stating "…for inclusion in that recovery mechanism."

f) #20 Real-Time Miscellaneous

The Department asked Xcel Electric, in DOC Information Request No. 40, to provide a description of types of costs included in Real Time Miscellaneous charges. In addition, the Department asked Xcel Electric to explain why total Real Time Miscellaneous charges (revenues) changed from $56,020 in FYE13 to ($1,195,508) in FYE14. Finally, the Department asked the Company to explain how it allocates Real Time Miscellaneous charges (revenues) between its retail and asset-based wholesale categories, and why it did not allocate any Real Time Miscellaneous charges to asset-based wholesale in FYE13 but did allocate some Real Time Miscellaneous revenues to asset-based wholesale in FYE14. Xcel Electric replied that:

> The majority of RT Miscellaneous charges relate to out of period dispute resolution adjustments and the settlement of automatic reserve sharing credits and charges.
>
> The primary driver of the Real Time Miscellaneous charges (revenues) year over year change is that credits received in FYE14 were PJM market to market adjustments.
>
> The amount included in RT Miscellaneous charges (revenues) that was allocated to the asset-based wholesale category represented credits for Real Time Multi-Value Project (MVP) Distribution, which represent monthly credits from MISO-held MVP ARRs. The MVP Auction Revenue Rights (ARRs) are treated as options and will always result in credits to those who paid for the MVP Projects. These amounts are included in base rates and therefore reclassifying these balances to asset-based wholesale category is consistent with expectations.
>
> In 2013, this MISO charge/credit type was not active so no amounts were provided to Xcel Energy, and therefore no amounts were allocated to asset-based wholesale.

The Department reviewed Xcel Electric's base rates in its most recent rate case in Docket No. E002/GR-13-868 and was unable to identify any MVP ARR revenues included in the test year. Moreover, based on an email exchange between the Department and Xcel Electric last year, the Department understood that MVP ARR revenues would be returned to ratepayers in the Company's TCR tracker. Upon further review of the Company's most recent TCR Rider in Docket No. E002/M-14-852, the Department was unable to identify these MVP ARR revenues.

As a result, the Department recommends that the Company return its FYE14 MVP ARR revenues in its next TCR Rider. For the record, the Department notes that Minnesota Power and Otter Tail Power were directed by the Commission to include their MVP ARR revenues in their most recent TCR Riders in Docket Nos. E015/M-14-337 and E017/M-14-375, respectively.

g) Allocation of MISO Day 2 Charges

The Department also reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset based wholesale/intersystem and non-asset based wholesale/intersystem. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[84] The Department asked Xcel Electric, in DOC Information Request No. 34, if any of the allocation methods used to allocate charges (revenues) between retail and asset-based wholesale changed during the 2013-2014 reporting period. In its response, Xcel stated that there were no changes in allocation methodology between retail and asset-based wholesale during the 2013-2014 reporting period.

h) Summary

The Department recommends that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

2. Review of MP's MISO Day 2 Charges

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE14 AAA Report and, with the exceptions described below, concludes that they are reasonable.

As an overview, the Department notes that MP's total MISO charges in FYE11, FYE12, FYE13, and FYE14 totaled \$58.1 million, \$52.0 million, \$62.7 million, and \$61.2 million, respectively. MISO charges allocated to MP's retail customers during those four years, in chronological order, were \$51.1 million, \$44.3 million, \$56.7 million, and \$58.4 million.

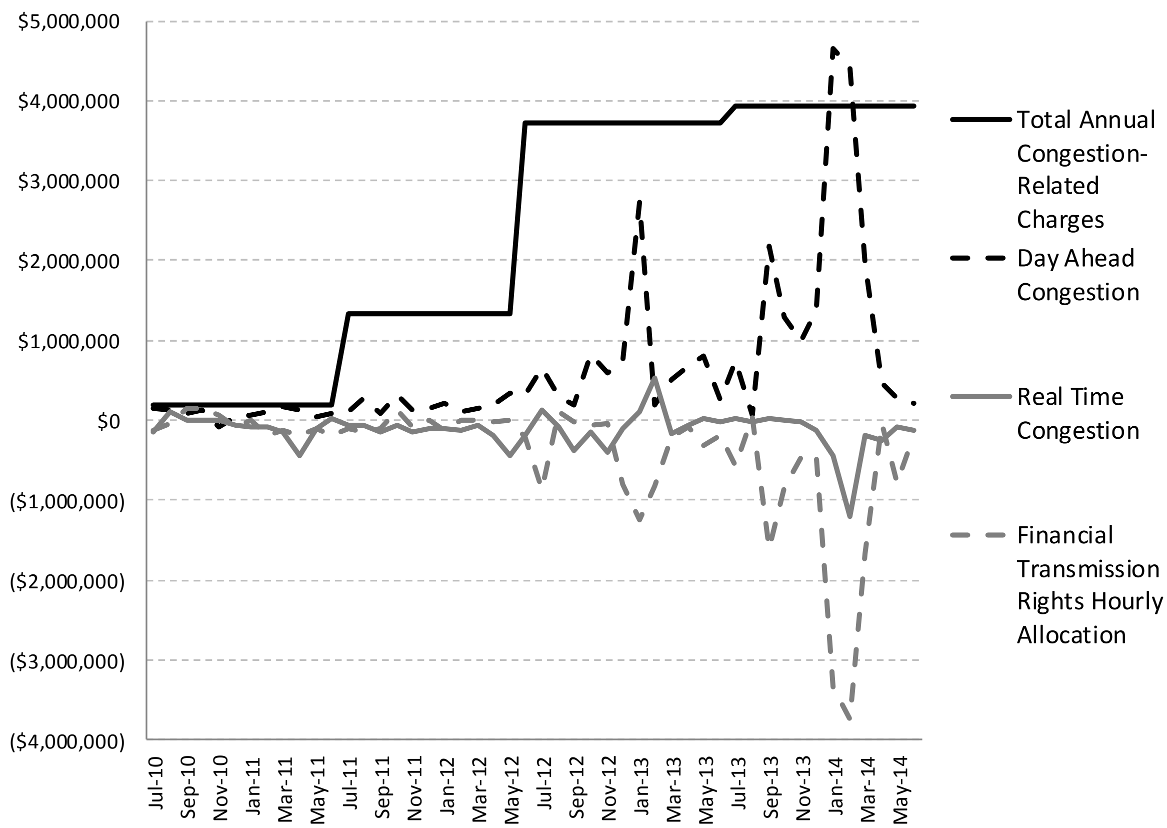
MP's Day-Ahead Asset Energy Charges in September 2013 and May 2014 were \$8.7 million and \$8.9 million, respectively; higher than in any other month since at least July 2010. The

[84] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

Department requests that MP explain in reply comments the reasons for the high charges observed in those months.

The Department notes that MP's Day-Ahead Congestion Charges also spiked in September 2013, along with January 2014 and February 2014, as shown in the table below. However, MP's hourly financial transmission right credits increased in those months as well, and despite the volatility in Day-Ahead Congestion, MP's total congestion charges in FYE14 ($3.9 million) were comparable to its total charges in FYE13 ($3.7 million).

Figure 3: Minnesota Power
Selected Congestion-Related Charges



Source: MP AAA Reports

The Department notes that MP's total congestion-related charges during the last two years have been much higher than the prior two years. The solid black line in the chart above shows MP's total annual congestion-related charges in FYE11 through FYE14. In FYE11 and FYE12, the total charges were approximately $0.2 million and $1.3 million, respectively. The Department will continue to monitor MP's congestion-related charges.

The Department also reviewed Minnesota Power's allocation of its MISO charges across its various customer categories. The Department described Minnesota Power's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic*

Adjustment Reports.[85] Because those allocation methods have not changed, the Department will describe them only briefly in this report.

Minnesota Power allocates energy-related charges (including several MISO Day 2 charges) using an algorithm that assigns highest-cost generation or purchases to non-FCA customer categories, theoretically leaving lowest-cost generation or purchases as the responsibility of Minnesota Power's FCA customers (retail and municipal customers). Virtual energy charges are directly assigned to the FCA customer categories. All other non-energy MISO costs are allocated on a per-MWh basis. The Department concludes that these allocation methods are generally reasonable, but cautions that it did not attempt to audit or verify the result of Minnesota Power's algorithm for allocating energy costs.[86]

3. Review of OTP's MISO Day 2 Charges

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Attachment K of OTP's 2013-2014 AAA Report. The Department notes that amounts totals reflected in Attachment K are at the total Company level and not the Minnesota jurisdictional level.

A summary of OTP's total MISO Day 2 charges assigned to retail customers for current and prior AAA reporting periods is provided below:

Total MISO Day 2 Charges Assigned to Retail

AAA Reporting Period	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014
Revenues	$175.1 million	$115.1 million	$87.0 million	$113.8 million	$173.1 million
Costs	$191.6 million	$131.2 million	$115.0 million	$145.2 million	$215.3 million
Net Costs	$16.5 million	$16.1 million	$28.0 million	$31.4 million	$42.2 million

The Department Reviewed OTP's MISO Day 2 charges as reported in Attachment K to its 2013-2014 AAA Report. The Department requested that OTP explain, through an information request, why the total 2013-2014 MISO Day 2 charges have increased from

[85] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

[86] As described in the Department's report in the FYE11 proceeding, the Department has some concerns about Minnesota Power's energy pricing algorithm. After highest-cost generation and purchases are allocated to non-FCA customers, all remaining energy costs are then assigned to the FCA customers. In theory, this process should produce the same result as a process in which lowest-cost resources were directly allocated to FCA customers, and the remainder was assigned to non-FCA customers. However, the Department is concerned that unspecified differences between theory and reality (caused by estimation, rounding, difficulty measuring usage, etc.) may cause unintended distortions in the allocation process that inappropriately raise costs for FCA customers.

$31.4 million in 2012-2013 to $42.2 million in 2013-2014, or a $10.8 million or 34 percent increase. OTP explained that the 2013/2014 winter was one of the coldest in the last 20 years due to the "polar vortex' weather pattern that existed across the upper Midwest, resulting in higher energy demand throughout MISO and an increase in market energy prices.[87] The Department concludes that this response is reasonable and has no overall concerns about the increase in MISO Day 2 charges for 2013-2014.

OTP's total for Day Ahead and Real Time Energy costs from July 2013 to June 2014 increased by approximately $55.4 million with an increase in revenues of approximately $48.0 million as compared to the previous year's filing. The majority of the increased costs appear to be related to an increase in the Day Ahead Asset Energy amount. The Department requested that OTP explain, though an information request, why the Company incurred increased Day Ahead and Real time Energy costs in the July 2013 to June 2014 as compared to the previous year, and why these costs are appropriately assigned to retail customers. OTP responded that the increase in Day Ahead and Real Time energy costs and revenues were primarily driven by weather during the December 2013 to March 2014 timeframe, and the associated increase in energy prices that resulted from increased demand.[88] The Department concludes that this response is reasonable and has no further concerns about OTP's total Day Ahead and Real Time energy costs for this time period.

OTP's total for Congestion and FTR costs from July 2013 to June 2014 increased by approximately $8.5 million with an increase in revenues of approximately $8.8 million as compared to the previous year's filing. These values represent almost a doubling of the corresponding values from July 2012 to June 2013. The majority of the increases in costs appear to be related to an increase in the FTR Annual Transaction Amount while the majority of the increase in revenue appears to be related to an increase in the FTR Auction Revenue Rights Transaction Amount.

The Department requested that OTP explain why the Company incurred such large increases in Congestion and FTR costs and revenues in the July 2013 to June 2014 period as compared to the previous year. OTP explained that the Company shifted its Big Stone and Coyote power plants from MISO Option B to Option A, resulting in OTP no longer receiving a congestion rebate, but instead receiving Auction Revenue Rights (ARRs)for these facilities. The associated costs and revenues for these plants are now tracked under the Congestion and FTR charge, and thus, in combination with seasonal fluctuations, resulted in the increases.[89] The Department concludes that this response is generally reasonable; however, the Department asks OTP to explain in its reply comments why ratepayers are better off under Option A compared to Option B, and to document that all ARRs are being returned to ratepayers.

Between December 2013 and March 2014 OTP reported that Day Ahead & Real Time Energy, Day Ahead & Real Time Energy Loss, Congestion and FTRs, and ASM Charges had substantially higher costs and revenues than the same period in the previous year. The Department requested that OTP explain why the Company incurred such large increases to

[87] Source: Otter Tail response to DOC IR 15. Please note that all OTP responses to discovery related to this section are provided in Attachment E14.
[88] Source: Otter Tail response to DOC IR 16.
[89]Source: Otter Tail response to DOC IR 17.

costs and Revenues in this period. OTP again stated that increased costs and revenues were driven by cold weather conditions during the "Polar Vortex." Specifically during December 2013 through March 2014 the average 24-hour day ahead LMP at the OTP load zone increased from $28.46/MWh during the same period in the 2012-2013 heating season to $50.18/MWh, which in turn increased costs and revenues for the period and is a direct function of participation and operation within the MISO market.[90] The Department concludes that this response is reasonable and has no other concerns about the general increases in costs and revenues during the December 2013 through March 2014 period.

OTP's FTR Hourly Allocation Amount costs totaled $2,395,984.37 in May, 2014, which is significantly higher than the costs charged in other months during the 2013-2014 AAA reporting period. The Department requested that OTP explain why the Company incurred such large FTR Hourly Allocation Amount costs in May, 2014 and why these costs are appropriately assigned to retail customers. In response OTP stated that a transmission maintenance outage occurred from April 23, the beginning of the MISO accounting month of May, to May 2nd on a 230 kV line. This outage caused a binding constraint to occur on the transmission system, which caused FTRs for OTP's Hoot Lake Plant to be largely negative, thus increasing costs during May, 2014.[91] The Department concludes that this response is reasonable and the costs are appropriately assigned to retail customers.

The Department also reviewed OTP's allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[92] In the reply comments in the 2012-2013 *Annual Automatic Adjustment Reports*[93] the Company stated that there were no changes in its allocation method since the previous report. The Department requested that OTP explain in this proceeding if any of the Company's allocation methods changed during the 2013-2014 reporting period and if so what the nature of these changes and the effect of these changes on the charges assigned to various customer categories in the 2013-2014 AAA Report. OTP responded that there were no changes to the allocation methods used during the 2013-2014 period. [94]

The Department also reviewed OTP's MISO bills to reconcile billing amounts shown in OTPs monthly allocation tables included in Part H, Section 13, Attachment K of OTP's initial filing. OTP provided the necessary data to allow this review and the Department found no issues with the calculations.

Therefore, the Department recommends that the Commission accept OTP's MISO Day 2 reporting, with the exception of FTR/ARR issue where the Departments asks OTP to explain in its reply comments why ratepayers are better off under Option A compared to Option B, and to document that all ARRs are being returned to ratepayers.

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[90] Source: Otter Tail response to DOC IR 18.
[91] Source: Otter Tail response to DOC IR 19.
[92] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.
[93] The Company's reply comments for the *2011-2012 Annual Automatic Adjustment Reports* was filed September 20, 2013 in Docket No. E999/AA-12-757.
[94] Source: Otter Tail response to DOC IR 20.

4. *Review of IPL's MISO Day 2 Charges*

Interstate Electric is unique in its treatment of MISO Day 2 costs compared to other Minnesota utilities, in that it does not allocate MISO Day 2 costs between retail customers and the wholesale sector, as all energy costs, all energy revenues, and all MWhs are included in its FCA. Interstate Electric uses the net of all costs and revenues and divides this amount by all MWhs. DOC considers this approach to be an all-in method, which was approved in Interstate Electric's prior rate cases. A benefit of this approach is simplicity, and the fact that there are no concerns about allocation proportions of MISO Day 2 costs between retail customers and the wholesale sector. Conversely, as part of this all-in process, efforts cannot be made to assign the lowest cost resources to retail customers.

As shown on Attachment C, page 13 of 13 for FYE11, FYE12, FYE13, and FYE14 AAA reports, the Department notes, prior to the sharp increase in FYE14, a decrease in Interstate Electric's MISO Day 2 charges, which include asset based wholesale in addition to retail. Below is a table showing Net Costs assigned to retail customers since 2010:

Table 4 - Historical MISO Day 2 Net Costs Assigned to Retail Customers

Period	Retail Costs	Retail Revenue	Retail Net Costs
2010-2011	$99,941,288.70	$20,127,899.82	$79,813,388.88
2011-2012	$92,291,999.68	$22,483,756.56	$69,808,243.12
2012-2013	$66,914,361.67	$25,260,345.97	$41,654,015.70
2013-2014	$138,772,043.91	$29,155,339.70	$109,616,704.21

In attempting to isolate the cause of the increase in retail costs in 2013-2014, the Department identified Congestion and FTR costs, along with Day Ahead & Real Time Energy costs as the main reasons for the increases in cost. Interstate Electric responded to information requests by the Department and offered explanations for the increase noted in FYE14.[95]

The Company briefly explained how the offer process in MISO is constructed, and how offers are cleared based upon LMPs. LMPs are comprised of multiple factors, including the cost of producing energy, the cost of physical energy losses incurred through transmission, and a monetization of the ability of the transmission system to transmit electricity between specific locations (congestion). MISO clears offers based on LMPs from lowest to highest amounts, thereby ensuring least cost delivered energy for load.

IPL stated that due to the high concentration of lower priced wind resources, the higher relative fuel costs and lower efficiencies of its generating units compared to others in the area, and the high levels of transmission congestion, the cleared generation volume from IPL is often less than its load. As a result of increased occurrences of these situations in FYE14, IPL purchased more MWs of load from MISO than it sold from its generators.

The Department notes that the 2013/2014 winter was one of the coldest in the last 20 years due to the "polar vortex" weather pattern that existed across the upper Midwest, resulting in higher energy demand throughout MISO and an increase in market energy

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

prices.[96] The Company stated in response to Department information requests that it purchased more MWs of load from MISO than it sold from generators.

While costs went up for all IOUs during the polar vortex, IPL's costs increased more sharply than for other IOUs, as shown, for example, by the steeper slope of the line for IPL between FYE13 and FYE14 indicated in Figure 2 above in this document. It appears that the steeper increase was caused by IPL's significant reliance on the MISO Energy Market at a time when LMPs were high.

The Department requests that IPL provide more information in Reply Comments to show why, even with the highly elevated LMPs, IPL's generation still was not dispatched in the MISO market. For example, IPL should provide the costs that IPL bid into the Day-Ahead and Real-Time markets during the polar vortex for IPL generators that were not dispatched, along with the LMPs for those days. IPL should also provide any other analysis the Company performed regarding the effect of the polar vortex on its Day-Ahead and Real-Time purchases and ultimately on the amount of purchased MWs from MISO despite the elevated LMPs due to the colder winter. The Department intends to review this information and provide recommendations regarding IPL's MISO Day 2 rates in response comments after the utilities' reply comments.

D. ASSET BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

Since the Department reviewed Xcel's asset-based margins in its current rate case (Docket E002/GR-13-868), the Department performed a cursory review of Xcel Electric's asset-based margins in the FYE14 AAA, to ensure the give back of asset-based margins to ratepayers via the FCA.

The Department reviewed Xcel Electric's asset-based margins for October 2013 in the FYE AAA and tied them back to Xcel Electric's FCA. As a result, the Department concludes that Xcel Electric's asset based margins appear reasonable.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2014, and compares those margins to the revenue credit built into MP's base rates. As shown, the sum of MP's actual margins over the six-year period ($216.5 million) is roughly equal to the total revenue credit ($218.8 million) over the same period, differing by only 1.0 percent. However, as shown, the large benefit to shareholders (where ratepayers received a smaller revenue credit in rates than MP actual received) in margin in 2009 has been offset by the small losses each year from 2010 through 2014 (where ratepayers benefited by receiving a larger revenue credit in rates than MP actually received). The Department will continue to monitor MP's wholesale margins in future AAA filings.

[96] Source: Otter Tail response to DOC IR 15 provided in Attachment E14.

Minnesota Power
Wholesale Asset-Based Margins

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Loss)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
2014	$34.7	$37.7	($3.0)	-8.0%
Total	$216.6	$218.8	($2.2)	-1.0%

Sources:
2009 and 2010 Actuals: MP Response to DOC Information Request No. 58 in FYE09 and FYE10 AAA Proceeding
2011 Actual: MP's response to DOC Information Request No. 1 part (E) in Docket No. E015/M-11-1264.
2012 Actual: MP Response to DOC Information Request No. 21 in Docket No. E999/AA-12-757
2013 Actual: MP Response to DOC Information Request No. 10 in Docket No. E999/AA-13-599
2014 Actual: MP Response to DOC Information Request No. 6 in the instant proceeding
2009 Revenue Credit in Base Rates: May 4, 2009 Order in Docket No. E015/GR-08-415, page 17
2010-2014 Revenue Credit in Base Rates: November 2, 2010 Order in Docket E015/GR-09-1151

3. OTP

The Department reviewed OTP's asset-based margins for November 2013 in the FYE14 AAA and tied them back to OTP's FCA. As a result the Department concludes that OTP's asset based margins appear to be reasonable.

4. IPL

Due to IPL's all-in approach where all revenues and costs for retail and wholesale customers are included in their FCA and divided by total kWh, asset based margins are embedded in IPL's total net fuel costs.

E. DOC INVOLVEMENT IN MISO PROCESSES

The DOC participates in Organization of MISO States (OMS) Workgroups which correspond with MISO workgroups and subcommittees. This approach has been a useful process for providing joint filings with FERC on the more significant MISO filings. The OMS has also helped the DOC be more proactive in its interaction with MISO. The DOC continues to attend or listen to MISO Advisory Committee (AC) Meetings, Annual Stakeholder and Sector Meetings with MISO, Resource Adequacy Workgroup and Supply Adequacy Workgroup (RAWG/SAWG) Meetings, Planning Advisory Committee (PAC) Meetings, Midwest Transmission Expansion Plan (MTEP) Meetings, Demand Response Meetings and other MISO meetings to gain better understanding of MISO proposals prior to implementation.

The DOC also participates in MISO issues via our Public Consumer Group Sector for sector voting issues largely at MISO AC and PAC Meetings, Hot Topic Comments, and Return on Equity (ROE) Complaint at FERC.

The DOC has also found the Minnesota Commission's MISO Quarterly Meetings to be helpful to share information and ask questions of the Utilities and MISO experts. The DOC greatly appreciates the efforts by the Commission to bring all of the parties together and to facilitate the discussions. The Department also appreciates the participation of all entities in this process. In particular, the DOC commends the Commission for focusing the discussions, and thanks the utilities and MISO for their significant efforts, discussions, and willingness to solve problems as they arise.

F. SUMMARY OF CONCLUSIONS REGARDING MISO DAY 2 COSTS AND REVENUES

The DOC concludes that the review of MISO Day 2 charges and allocations are complex, due to the volume of information related to these transactions, the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions and some of the utilities' fuel clause ratemaking processes.

Overall, utilities have improved the quality of their explanations regarding fluctuations and/or changes in MISO Day 2 overall costs and charges. As noted above, the DOC still has some remaining questions about overall MISO charges and cost allocations that we have asked utilities to respond to in their reply comments. Once this information is provided, the DOC will review the additional information and make our final recommendations to the Commission.

The DOC intends to continue to audit the MISO Day 2 charge and allocations between retail and wholesale customers. The DOC includes a list of all its recommendations formulated at this time, including recommendations for this MISO Day 2 section, below in the recommendations section.

VIII. ANCILLARY SERVICES MARKET (ASM)

A. BACKGROUND

Utilities must hold enough capacity to meet their load and provide reliable service to comply with North American Electric Reliability Corporation (NERC) reliability standards. The reliability component includes ancillary services. Ancillary services ensure that there is sufficient generation to match loads on the transmission system instantaneously to preserve service reliability.

These ancillary capabilities are as follows:

- Regulation service: having generation operating and able to change their MW output (up or down) to respond to changes in load on a second-by-second basis;
- Spinning Reserve service: having generation on line (spinning) at reduced output, so that it can immediately provide replacement power in the event of an unscheduled outage at another generation unit;
- Supplemental Reserve service: having generation readily available off-line and capable of starting and beginning to generate within ten (10) minutes to respond to an unscheduled outage at another generation unit; and
- Energy Imbalance service: providing energy between entities, such as between a utility and a municipal load-serving entity (which is typically a wholesale customer of the utility), to account for the difference between the amount scheduled during a period (such as an hour) and the amount actually delivered (which may be more or less than the amount scheduled). Energy Imbalance service could be settled either by an "in kind" exchange of energy in a later period, or financially.

MISO's Ancillary Services Market (ASM) began operations on January 6, 2009. The 12 ASM charges are as follows:

Six Procurement charges:	1) Day-Ahead Regulation; 2) Day-Ahead Spinning Reserve Charge; 3) Day-Ahead Supplemental Reserve; 4) Real-Time Regulation; 5) Real-Time Spinning Reserve; 6) Real-Time Supplemental Reserve;
One Resource Energy charge:	1) Net Regulation Adjustment;
Three Cost Distribution charges:	1) Regulation; 2) Spinning Reserve Charge; and 3) Supplemental Reserve; and
Two Penalty charges:	1) Regulation Penalty Amount; and 2) Contingency Reserve Development Failure Penalty.

Prior to the start of MISO's ASM, ancillary services were procured in the MISO footprint by each utility through bilateral contracts via Balancing Authorities to the MISO as the Provider of Last Resort. On a day-ahead basis, individual Balancing Authorities identified how resources in their Balancing Authority area (formerly referred to as a "control area") would be able to provide the required amounts of ancillary service, which resulted in capacity on native generation resources being held back to provide services of regulation, spinning reserve and supplemental reserve. On a real-time basis, Balancing Authorities dispatched their resources on a second-by-second basis to meet system reliability requirements. If the utility was unable to meet the energy requirements needed to serve their load and provide the necessary ancillary services, they were required by NERC reliability standards to purchase additional energy while they held back capacity to meet reliability needs.

The Commission's Order dated August 23, 2010 in Docket No. M-08-528 (Commission's August 23, 2010 ASM Order) approved Xcel Electric's, MP's, and Interstate Electric's ASM accounting and recovery via the FCA and required reporting requirements as follows (the DOC notes that OTP's ASM was approved via their rate case in GR-10-239):

> 1. The Commission accepts the quarterly reports filed by the three utilities under the March 17, 2009 order in this case.
>
> 2. The Commission finds that the record demonstrates overall benefits from the three utilities' participation in the MISO ancillary services market and that the record supports the continued use of the Fuel Clause Adjustment to pass through the costs and revenues associated with that participation. The three utilities are authorized to continue using the Fuel Clause Adjustment to pass through the costs and revenues associated with their participation in the MISO ancillary services market.
>
> 3. With the exception of Contingency Reserve Deployment Failure Charges and Excess/Deficient Energy Charges, the Commission removes the "subject to refund" provisions of the March 17, 2009 order for both past and future ancillary services market costs passed through the Fuel Clause Adjustment.
>
> 4. All costs and revenues associated with the utilities' participation in the MISO ancillary services market remain subject to the normal review, approval, and recovery procedures that apply to costs and revenues passed through the Fuel Clause Adjustment.
>
> 5. The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 *et seq.*, including the annual filing required there under. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings, which are due in September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.
>
> 6. The three utilities shall continue to monitor and report all negative benefits (costs) of participation in the MISO ancillary services market and shall work with MISO to

ensure that negative benefits occur, if at all, for limited periods of time and with minimal financial impact.

7. The three utilities shall base the formatting of their reports on costs and revenues associated with participation in the MISO ancillary services market on the format used by Xcel and Minnesota Power in this docket.

8. In their annual summaries on the 12 MISO ancillary services charges the utilities shall use a format similar to that used by Minnesota Power in its Attachment 1 to its February 5, 2010 filing (4th quarter report) and shall work with the [Department] to develop a format that is acceptable.

9. In reporting daily ancillary services market activity and overall net savings created by participation in the ancillary services market, utilities shall use a format similar to that used by Xcel in Attachment A to its February 5, 2010 filing and shall work with the [Department] to develop a format that is acceptable.

10. The utilities' written narratives on the benefits of the ancillary services market and the market's impact on their systems shall be formatted consistent with Xcel's and Minnesota Power's 4th quarter report in this docket.

11. The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an explanation as to why they should be recovered and what actions the utility took to minimize these charges.

12. The utilities shall clearly identify and separately list in their automatic adjustment reports all ancillary services market values included in those reports and/or passed through the Fuel Clause Adjustment.

One focus of the Department's review is on the extent to which a utility incurs penalty charges; thus, the Department begins by describing these penalties. First, the Excessive/Deficient Energy Deployment Charge amount represents the charge to the generator that was not able to maintain actual generator output to within a tolerance band around the set point. During the hours where a generator was unable to meet this requirement, MISO assesses a charge equal to any Day-Ahead or Real-Time payments to the generator for carrying regulation reserve plus the generator's pro rata share of costs to procure regulation from all resources within MISO.

Second, the Contingency Reserve Deployment Failure Charge represents the charge incurred by generation or demand response resources that fail to deploy contingency reserves at or above the contingency reserve deployment instruction. This charge is assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform, and MISO must then deploy another resource.

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE14 AAA filing in Part J, Section 5, Schedules 8 to 13 and in Part J, Section 6 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric stated the following regarding overall ASM market performance:[97]

> During the 2012-2013 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its 2013 State of the Market Report that "The MISO energy and ancillary service markets generally performed competitively in 2013." The Market Monitor also noted 2013 prices were 1.7% price-cost mark-up in 2013 and that 2013 prices were 12.2% higher than 2012 due to higher natural gas prices. (Footnotes omitted)

A summary of Xcel Electric's total MISO ASM charges assigned to retail customers on a total company basis for current and prior AAA reporting periods is provided below:

Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014
Net Costs	($3.9)[98]	$0.8[99]	$3.5[100]	$13.9[101]	$24.7[102]	$23.5[103]

The Department notes that Xcel's retail ASM costs increased over time and decreased slightly from $24.7 million in FYE13 to $23.5 million in FYE14.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE14.[104] The Company shows net ASM savings of $10.5 million for the total NSP system and $7.9 million

[97] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Page 1 of 6.
[98] Source: Xcel's initial filing in Docket No. E999/AA-09-961, Part J, Section 5, Schedule 13, Page 7 of 73.
[99] Source: Xcel's initial filing in Docket No. E999/AA-10-884, Part J, Section 5, Schedule 13, Page 13 of 13.
[100] Source: Xcel's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 13, Page 13 of 13.
[101] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[102] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[103] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[104] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Page 2 of 6.

for the Minnesota Jurisdiction. Xcel stated that these net savings are associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint. In addition, Xcel stated that its net savings calculation did not include any additional benefits that have accrued to ratepayers for the reduction in regional regulatory reserve requirements.

a) Excessive/Deficient Energy Deployment Charges (EDEDC)

Xcel discussed and provided its monthly Excessive/Deficient Energy Deployment Charges (EDEDC) in Part J, Section 6 of its filing. EDEDC amounts are charges a utility incurs when a generator is not able to maintain actual generator output within a tolerance band around the set point.

The Department notes that Xcel's total system EDEDC increased from $979,562[105] in FYE13 to $1,368,932[106] in FYE14, an increase of 40 percent.

According to Xcel Electric, a certain level of EDEDC is unavoidable given the current design of the ASM. The Company stated that its ASM net benefit calculation is a measure of the extent to which the Company has struck the appropriate balance between too much or too little flexibility being offered to MISO. The Company stated that its ASM net benefit of $10.5 million would not have been achievable if the Company had been offering ramp rates for units that would have all but eliminated the chance of incurring EDEDC charges. The Company also stated that:

> To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants on a daily basis to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected – and prudent – in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.
>
> In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in EDEDC charged to the Company began in January

[105] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Schedule 2, Page 1 of 1; sum of all months for FYE13.
[106] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Schedule 2, Page 1 of 2; sum of all months for FYE14.

> 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase was offset by an increase in the revenues received by the Company for Regulation. During the period of January 2014 through June 2014, EDEDC charges have declined by $83,294 as compared to a similar period from last year.
>
> As a follow-up to last year's report, we reported a significant increase in Sherco 1 and 2 charges during this reporting period last year. After further investigation, Sherco units sell significant regulating reserves to MISO, and the sale price has two components: capacity and mileage. If regulation is not deployed or Sherco fails to follow dispatch, MISO "claws back" the mileage payments. The charges look the same whether Sherco failed to deploy or was not called upon. Only by netting the mileage payments against the charges are we able to determine the actual costs of failure to follow dispatch.

Based on the above, the Department concludes that Xcel Electric's EDEDC charges may be reasonable. However, given the significant increase in EDEDC charges in FYE14, the Department recommends that the Company provide a plan to mitigate these costs in the future.

b) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE14 in Part J, Section 6 of its filing. CRDFC amounts are incurred when generation or demand response resources fail to deploy contingency reserves at or above the contingency reserve deployment instruction. These charges are assessed if a unit that is selected to provide spinning our supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

The Department notes that Xcel Electric's total system CRDFC decreased from $53,160[107] in FYE13 to $11,671[108] (78 percent) in FYE14. Regarding its FYE14 CRDFC, Xcel stated that:

> The charges were not the result of any improper action by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy

[107] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Schedule 3, Page 1 of 1; sum of all months for FYE13.
[108] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 6, Schedule 2, Page 2 of 2; sum of all months for FYE14.

> reserves from another generator in its fleet, and would have incurred increased energy costs that were recovered in the FCA. Thus it is reasonable for the Company to recover these minor charges from MISO.
>
> The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.
>
> In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100% of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

Based on the above, the Department concludes that Xcel Electric's CRDFC charges appear reasonable.

c) #4 Real-Time Regulation Amount

The Department noted that out of a total net invoice amount of $333,713.83, retail was assigned costs of $1,874,120.64 and asset-based margin was assigned revenues of ($1,540,406.81) for Real-Time Regulation Amount charges in FYE14.[109] As a result, the Department asked the Company to explain this allocation between retail and asset-based wholesale in Department Information Request No. 43. Xcel Electric replied that:

> In order to determine the amount allocated to asset-based margins, the Day-Ahead Regulation Amount, Real Time Regulation Amount, and Real Time Regulation Reserve Cost Distribution Amount are aggregated. The sum of that calculation is re-classed by a journal entry that affects only the Real Time Regulation Amount. Therefore, the asset-based

[109] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.

> margin amounts in the Day-Ahead Regulation Amount, as well as the Real Time Regulation Reserve Cost Distribution, are not disclosed separately.

The Department added up the total net invoice amounts for the three charges identified in Xcel Electric's response to Department Information No. 43. The Department found that the net invoice amount for these three charges totaled ($1,454,309.39) in FYE14, of which retail was assigned costs of $86,097.42 and asset-based wholesale was assigned revenues of ($1,540,406.81). [110] The Department recommends that Xcel Electric fully explain in reply comments the method or methods used to allocate these three charges between retail and asset-based wholesale in its journal entry.

d) #5 Real-Time Spinning Reserve Amount

The Department noted that out of a total net invoice amount of ($542,673.69), retail was assigned costs of $475,364.77 and asset-based margin was assigned revenues of ($1,018,038.46) for Real-Time Spinning Reserve Amount charges in FYE14. The Department asked to Xcel Electric to explain this allocation between retail and asset-based wholesale in Department Information Request No. 44. Xcel Electric replied that:

> In order to determine the amount allocated to asset-based margins, the Day-Ahead Spinning Reserve Amount, Real Time Spinning Reserve amount, and Real Time Spinning Reserve Cost Distribution are aggregated. The sum of that calculation is re-classed by a journal entry that affects only the Real Time Spinning Reserve Amount. Therefore, the asset-based margin amounts in the Day-Ahead Spinning Reserve Amount, as well as the Real Time Spinning Reserve Cost Distribution, are not disclosed separately.

The Department added up the total net invoice amounts for the three charges identified in Xcel Electric's response to Department Information No. 44. The Department found that the net invoice amount for these three charges totaled ($116,026.82) in FYE14, of which retail was assigned costs of $902,011.64 and asset-based wholesale was assigned revenues of ($1,018,038.46). [111] The Department recommends that Xcel Electric fully explain in reply comments the method or methods used to allocate these three charges between retail and asset-based wholesale in its journal entry.

e) Summary

The Department recommends that the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the requested information in its reply comments.

[110] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[111] Source: Xcel's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.

C. MP

MP addresses ASM costs and benefits in Attachment 10 to its FYE14 AAA Report. MP reported a net cost of $303,890 for FYE14, compared to net costs of $74,441 and $184,594 in FYE13, and FYE12, respectively, and a net *benefit* of $69,340 in FYE11. Compared to FYE13, during FYE14 MP's net purchases of regulation, spinning and supplemental services each declined, but the costs of the spinning and supplemental services it purchased increased.

Additionally, MP's real time excessive deficient energy deployment charge amount increased by approximately $110,000. MP's FYE14 contingency reserve deployment failure charge amount of $2,757 was largely unchanged from FYE13 ($788).

MP treats ASM charges and credits as non-energy costs and allocates them across customer categories on a per MWh basis. The Department considers this allocation method to be reasonable.

Attachment 10-A, page 6 compares MP's MISO Schedule 17 charges prior to the start of the AMS market to its Schedule 17 charges in FYE14. In FYE14, average MISO Schedule 17 charges totaled $167,846, or $29,924 higher than the average monthly charges prior to the start of the ASM market. This amount equates to an average monthly increase of $0.00433 per MWh.

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

D. OTP

In Section V, Attachment L its FYE13 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, OTP noted that ASM market transition has been smooth from an operational standpoint. OTP noted that there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has led to greater operational efficiency. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, and Supplemental Reserve). As a result, ASM provided net benefits of $204,356 to Minnesota ratepayers in 2013-2014. OTP allocates all ASM charges on a per MWh approach netting costs and benefits of the various charges.

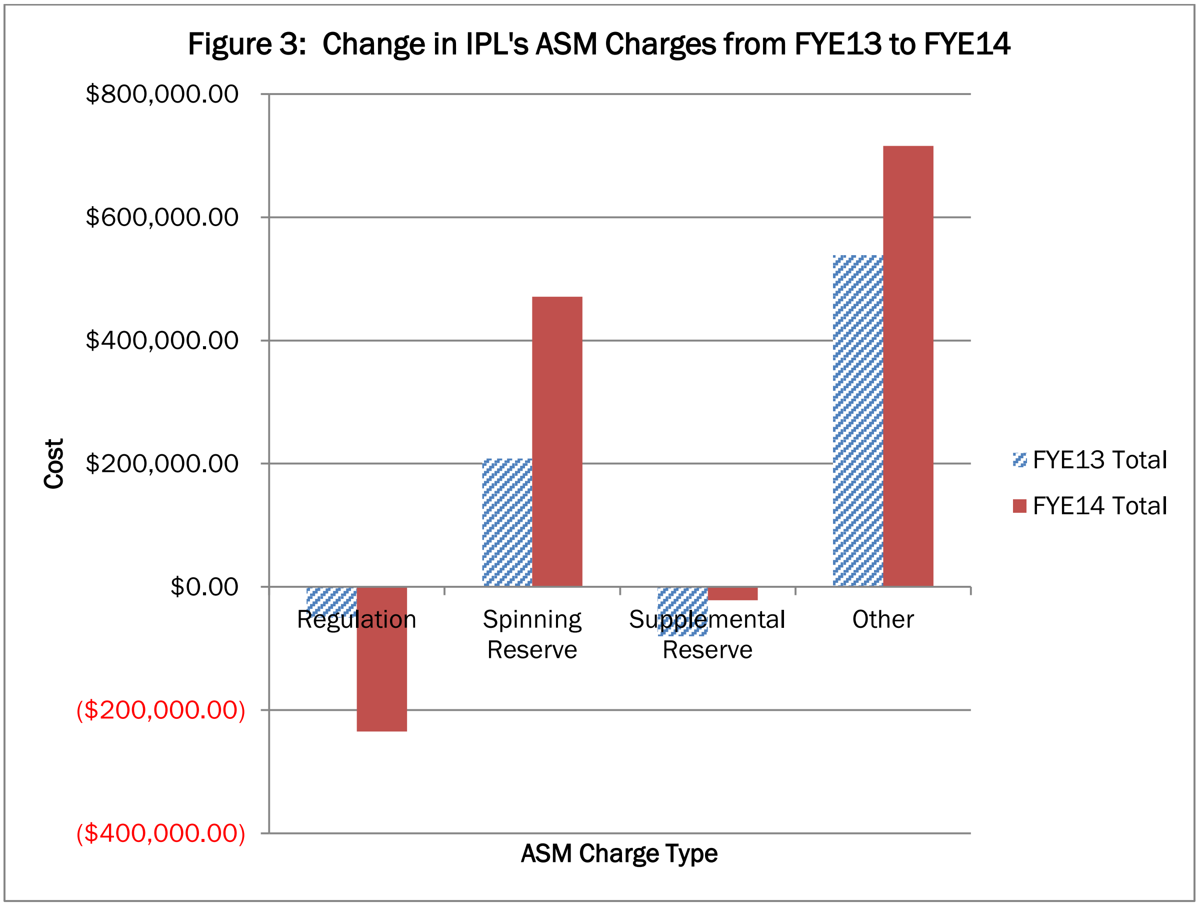
The Department notes that ASM net benefits decreased somewhat from $282,691 in 2012-2013 to $204,356 in 2013-2014. The Department recommends that the Commission accept OTP's ASM reporting.

E. INTERSTATE ELECTRIC

Included in Attachments D through F of its FYE14 AAA filing, Interstate Electric provided its ASM information as required by the Commission.[112] Pages 1 through 8 in Attachment D detail the Regulation, Spinning Reserve, Supplemental Reserve, and Other Charges and

[112] Commission's August 23, 2010 Order in Docket No. M-08-528.

resulting subtotals for all four quarters included in FYE14. The DOC notes that for Regulation and Supplemental Reserves in FYE14, Interstate Electric was a net purchaser for Regulation and Supplemental Reserve, and a net seller for Spinning Reserve, as Figure 3 below illustrates. Figure 3 also illustrates these same values for the FYE13 AAA filing from IPL, which shows large differences in the Regulation and the Spinning reserve subtotals between the two periods. The subtotal for Other Charges in FYE14 was $716,065.74.[113] This amount is 33 percent higher than the $538,708.58 level in FYE13 and 918 percent higher than the $70,334 reported for FYE12 AAA filing.[114]



For a third year in a row, the reason for the significant increase to the Other Charges amount in FYE14 was an increase in the Excessive/Deficient Energy Deployment Charge Amount (EDEDC), described above. Units that were able to provide Regulation more efficiently than others were rewarded, examples of which included flywheels, which are explicitly designed to provide Regulation. Interstate Electric does not own any flywheels, and still offers and is awarded to provide Regulation. Interstate Electric stated that their assets are not suited to meet the Regulation Mileage criteria and they have therefore been assessed EDEDC charges.

113 IPL 2014 Annual Filing Attachment D, "Other Charge Subtotal" for all four quarters in the reporting period.
114 IPL 2012 and 2013 Annual Filings, Attachment D, "Other Charge Subtotal" for all quarters in the reporting period.

In Attachment H, Interstate Electric explained that the EDEDC charges began to increase significantly upon a tariff change by MISO that implemented Regulation Mileage in December of 2012.[115] The Department issued information requests to the Company to further clarify the nature of the increasing charges and detail any plans to curb the increasing costs.[116] The Company responded that it has evaluated its generation fleet and each unit's ability to respond and has ceased making regulation offers for certain units that are less responsive and would result in higher EDEDC penalty costs.

The Department agrees that it is necessary for IPL to reduce EDEDC penalty costs. What is not clear is why IPL did not take action sooner, given that IPL experienced high penalty costs in the past few years, as noted above, and was aware that the change in MISO's tariff was a major factor causing that increase. Thus, the Department requests that IPL explain in reply comments why its ratepayers should pay for the high level of EDEDC penalty costs charged to IPL during this reporting period.

In Attachment F, Interstate Electric reported three instances of Contingency Reserve Deployment Failure (CRDF) penalties, totaling $1,347.50 incurred during the current reporting period. This amount is a decrease of approximately $16,000 from FYE13. Interstate Electric stated that the costs incurred from the CRDF penalties were due to issues primarily with units' inability to ramp up in a timely manner.[117] The CRDF penalties in FYE14 signify a considerable decrease from those in FYE13.

Interstate Electric additionally provided an Economic Savings Analysis for all four quarters of the reporting year in Attachment E. The economic savings are realized because Interstate Electric is longer required to "hold back" generators in order to provide ancillary services and can instead gain margin on the energy sales accrued by these generators. Prior to ASM, some low-cost coal generation had to be "held back" to allow Interstate Electric to self-provide ancillary services, which incurred an opportunity cost as the units could not be offered into the MISO market and garner a higher payment than the fuel and operating costs. Interstate Electric calculated these benefits, less the MISO Schedule 17 administrative costs for ASM, resulting in total net benefits of $2,215,104.66 for the current reporting period.[118] In the prior two reporting periods, total net benefits were $1,766,625.64 for FYE13 and $2,378,964.50 for FYE12.

While Interstate Electric has done a reasonable job explaining its ASM compliance filing, the Department requests that IPL explain in reply comments why its ratepayers should pay for the high level of EDEDC penalty costs charged to IPL during this reporting period, given the information IPL knew about the structure of MISO's tariff pertaining to these costs. The DOC will provide its recommendations on Interstate Electric's ASM costs after reviewing that information.

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[115] IPL 2014 Annual Filing Exhibit H, Page 21
[116] MN DOC Information Request No. 31 Issue April 6, 2016, response received April 16, 2015
[117] *Ibid*
[118] *Id,* Attachment E, "Energy Savings less Sch. 17 Charges ASM Allocation" for all four quarters in the reporting period

IX. CHARTS FOR INFORMATIONAL PURPOSES

Attachment E15 shows various aspects of fuel charges and the effects on customers' bills.

1. Average Residential Bills for 2013

The graph on page 1 of 4 of Attachment E15 illustrates the monthly average bills for residential customers in calendar year 2013. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges (as described on pp. 3-4 of Attachment E15). Overall, Otter Tail had the highest average monthly residential bill of $94.52, followed by Dakota Electric at $87.05, Interstate Electric at $86.84, Xcel Electric at $79.12 and Minnesota Power with the lowest average of $67.12 per month.

2. Energy Charge + FCA (cents per kWh) for Each Utility

The graph on page 2 of 4 of Attachment E15 shows the amounts that residential customers paid during calendar year 2013 in energy charges plus fuel clause adjustments. The ranking from highest to lowest average monthly amounts paid are: Dakota Electric with a 12-month average of 11.59¢/kWh, Interstate Electric with an average of 10.70¢/kWh, Xcel Electric 10.42¢/kWh, Otter Tail with an average of 8.16¢/kWh, and Minnesota Power 7.66¢/kWh. However, the Department notes that, because utilities recover different amounts of fixed costs in the energy charges, this comparison is not as useful as the bill comparison in item 1 above.

X. RECOMMENDATIONS

For Section III, Compliances, the Department recommends that the Commission accept the compliance filings A to O, as discussed in the relevant sections.

However, as explained above, because utilities have not fully explained why ratepayers should pay for certain costs, the Department requests further information from utilities in their reply comments. For example, as explained in Section III.C, the record at this time does not support a finding that it is reasonable for Xcel Electric to charge its ratepayers for the material increase in curtailment payments during FYE14. Other examples are listed below. The Department will review the utilities' responses to the Department's request for further information and intends to file its analysis in DOC's response comments to the IOUs' reply comments.

For Section IV, Rail Delivery Issues, the Department recommends that:

1. Otter Tail explain in reply comments why it opts to transport coal under tariff, rather than under long-term contract, and explain specifically what coal conservation measures it took during calendar year 2013 and the specific costs to ratepayers associated with those measures. Additionally, the Department requests that Otter Tail explain in reply comments whether it believes

transporting its coal under contracts, rather than under tariff, would help alleviate some of these delivery issues.

2. Xcel explain in reply comments whether it is possible to negotiate terms and conditions in its rail transportation contracts that would **[TRADE SECRET DATA HAS BEEN EXCISED].**

3. In reply comments, the Department requests that Xcel explain whether and how the terms and conditions of its rail contracts in the future can be strengthened in any other way to avoid the issue discussed in Section IV C 3 i above.

4. The Commission accept IPL's reporting with respect to fuel costs associated with coal shortages.

5. The Department will review MP's May 7, 2015 response to the Department's discovery and intends to offer its recommendations in DOC's response comments to the IOUs' reply comments.

For Section VI, Effects of the MISO Day 1 on Minnesota Ratepayers, the Department recommends the following:

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

- The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

For Section VII, Effects of the MISO Day 2, on Minnesota Ratepayers, the Department recommends the following:

Xcel Electric

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

- The Department understands that Day-Ahead Schedule 24 Allocation Amounts are assigned to retail and asset-based wholesale on an MWh basis. The Department requests that Xcel Electric confirm or clarify our understanding in reply comments.

- The Department recommends that Xcel Electric fully explain the following in reply comments:
    - why Real-Time Schedule 24 Distribution charges (revenues) are only assigned to asset-based wholesale;
    - why Real-Time Schedule 24 Distribution charges (revenues) are reclassified from asset-based wholesale to transmission revenues; and
    - which specific recovery mechanism Xcel Electric was referring to in stating "…for inclusion in that recovery mechanism."

- The Department recommends that the Commission require Xcel to return its FYE14 MVP ARR revenues in its next TCR Rider.

- The Department recommends that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

Minnesota Power

- The Department requests that Minnesota Power explain in its reply comments the reasons for the high Day-Ahead Asset Energy Charges observed in September 2013 and May 2014.

- The Department recommends that the Commission not accept MP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

Otter Tail Power

- The Department asks OTP to explain in its reply comments why ratepayers are better off under Option A compared to Option B, and to document that all ARRs are being returned to ratepayers.

- The Department recommends that the Commission not accept OTP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

Interstate Electric

- The Department requests that IPL explain in reply comments why, even with the highly elevated LMPs, IPL's generation was not dispatched in the MISO market. (For example, IPL should provide the costs that IPL bid into the Day-Ahead and Real-Time markets during the polar vortex for IPL generators that were not dispatched, along with the LMPs for those days.)

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

- The Department intends to review this information and provide recommendations regarding IPL's MISO Day 2 rates in response comments after the utilities' reply comments.

For Section VIII, Ancillary Services Market (ASM), the Department recommends the following:

Xcel Electric

- Given the significant increase in EDEDC penalty charges in FYE14, the Department recommends that the Company provide a plan to mitigate these costs in the future.

- The Department's analysis indicates that Xcel Electric's net invoice amounts for Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount totaled ($1,454,309.39) in FYE14, of which retail was assigned costs of $86,097.42 and asset-based wholesale was assigned revenues of ($1,540,406.81). The Department recommends that Xcel Electric fully explain in reply comments the method or methods used to allocate these three charges between retail and asset-based wholesale in its journal entry.

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

- The Department recommends that the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the requested information in its reply comments.

Minnesota Power

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

Otter Tail Power

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

Interstate Electric

- While Interstate Electric has done a reasonable job explaining its ASM compliance filing, the Department requests that IPL explain in reply comments why its ratepayers should pay for the high level of EDEDC penalty costs charged to IPL during this reporting period, given the information IPL knew about the structure of MISO's tariff pertaining to these costs.

- The DOC intends to provide its recommendations Interstate Electric's ASM costs after reviewing that information.

Public Document

Summary of Attachments to the Department's FYE14 AAA Report

Docket No. E999/AA-14-579

Attachment E1:

IOUs' Fuel Cost Projections 2015-2019

Attachment E2:

Xcel Electric's Wind Curtailment Payments: FYE06 through FYE14

Attachment E3:

Wind Curtailment Email

Attachment E4:

Annual Comparison of IOUs Net Energy Costs and Outages Costs: FYE06 through FYE14

Attachment E5:

IOUs Maintenance Expenses of Generation Plants: 2005-2013

Attachment E6:

Otter Tail Power Company's response to DOC discovery related to rail delivery issues

Attachment E7:

Interstate Electric's response to DOC discovery related to rail delivery issues

Attachment E8:

Xcel Electric's response to DOC discovery related to rail delivery issues

Attachment E9:

Dakota Electric Association: FYE14 Energy Cost Over/Under-Recovery

Attachment E10:

Interstate Electric: FYE14 Energy Cost Over/Under-Recovery

Attachment E11:

Minnesota Power: FYE14 Energy Cost Over/Under-Recovery

Attachment E12:

Otter Tail Power Company: FYE14 Energy Cost Over/Under-Recovery

Attachment E13:

Xcel Electric: FYE14 Energy Cost Over/Under-Recovery

Attachment E14:

Otter Tail Power Company response to the Department's discovery regarding MISO Day 2

Attachment E15:

Minnesota Electric Utilities' Average Residential Bills for 2013

Attachment E16:

Background Information on Fuel Clause Issues from Recent Dockets

Attachment E1

IOUs' Fuel Cost Projections 2015-2019

Fuel Cost Projections ($/MWh) for 2015 through 2019

$/MWh	2015	2016	2017	2018	2019
	Trade Secret Data Has Been Excised				
(1) Dakota					
(2) IPL					
(3) MP					
(4) OTP					
(5) Xcel Electric					

Annual and Cumulative Percent Change in Fuel Cost for 2016 through 2019

	2015	2016	2017	2018	2019	2015-2019
	Trade Secret Data Has Been Excised					
Dakota						
IPL						
MP						
OTP						
Xcel Electric						

Source:
(1) Exhibit D, page 2 of 2, Dakota's August 26, 2013 AAA report in Docket No. E999/AA-14-579.
(2) Exhibit E, page 2 of 2, IPL's August 29, 2014 AAA report in Docket No. E999/AA-14-579.
(3) Attachment 4, page 3 of 3, MP's August 29, 2014 AAA report in Docket No. E999/AA-14-579.
(4) Page 145-149 of 212, OTP's August 29, 2014 AAA report in Docket No. E999/AA-14-579.
(5) Part G, Section 1, Schedule 1, pages 1-5 of 5, Xcel's September 2, 2014 AAA report in Docket No. E999/AA-14-579.

Attachment E2

Xcel Electric's Wind Curtailment Payments: FYE06 through FYE14

Source: Xcel's monthly FCAs and input data emails

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-05	$ 2,209,107	$ 25,541	1.16%	0.00001
Aug-05	$ 1,518,401	$ 402	0.03%	0.00000
Sep-05	$ 2,980,966	$ 226,425	7.60%	0.00006
Oct-05	$ 2,672,444	$ 299,556	11.21%	0.00008
Nov-05	$ 3,246,917	$ 63,469	1.95%	0.00002
Dec-05	$ 2,310,360	$ 14,611	0.63%	0.00000
Jan-06	$ 3,181,045	$ 149,230	4.69%	0.00004
Feb-06	$ 2,928,149	$ 34,409	1.18%	0.00001
Mar-06	$ 3,225,927	$ 82,933	2.57%	0.00002
Apr-06	$ 3,277,251	$ 172,533	5.26%	0.00005
May-06	$ 3,420,464	$ 155,300	4.54%	0.00005
Jun-06	$ 1,794,434	$ 47,056	2.62%	0.00001
FYE06	$ 32,765,465	$ 1,271,465	3.88%	0.00003
Jul-06	$ 2,022,618	$ 21,751	1.08%	0.00000
Aug-06	$ 1,622,157	$ 49,915	3.08%	0.00001
Sep-06	$ 2,137,230	$ 21,205	0.99%	0.00001
Oct-06	$ 3,735,580	$ 187,961	5.03%	0.00005
Nov-06	$ 3,750,604	$ 96,229	2.57%	0.00003
Dec-06	$ 4,420,067	$ 145,404	3.29%	0.00004
Jan-07	$ 5,269,373	$ 253,194	4.81%	0.00007
Feb-07	$ 3,667,764	$ 88,835	2.42%	0.00003
Mar-07	$ 5,058,108	$ 82,644	1.63%	0.00002
Apr-07	$ 4,590,927	$ 152,683	3.33%	0.00005
May-07	$ 5,346,822	$ 545,568	10.20%	0.00016
Jun-07	$ 3,491,293	$ 504,074	14.44%	0.00013
FYE07	$ 45,112,543	$ 2,149,463	4.76%	0.00005

Xcel	Wind Costs (l)		Curtailment Payments (m)		Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-07	$	2,409,324	$	31,773	1.32%	0.00001
Aug-07	$	1,923,872	$	33,751	1.75%	0.00001
Sep-07	$	4,869,010	$	782,876	16.08%	0.00021
Oct-07	$	5,442,224	$	1,000,320	18.38%	0.00027
Nov-07	$	8,214,094	$	2,823,623	34.38%	0.00082
Dec-07	$	6,291,719	$	423,078	6.72%	0.00011
Jan-08	$	8,362,879	$	30,628	0.37%	0.00001
Feb-08	$	7,021,472	$	142,412	2.03%	0.00004
Mar-08	$	7,816,746	$	14,281	0.18%	0.00000
Apr-08	$	10,118,928	$	714,484	7.06%	0.00021
May-08	$	8,781,452	$	25,464	0.29%	0.00001
Jun-08	$	5,840,030	$	394,186	6.75%	0.00011
FYE08	$	77,091,750	$	6,416,876	8.32%	0.00014
Jul-08	$	4,860,293	$	25,680	0.53%	0.00001
Aug-08	$	5,114,362	$	-	0.00%	0.00000
Sep-08	$	7,195,808	$	314	0.00%	0.00000
Oct-08	$	8,287,796	$	39,601	0.48%	0.00001
Nov-08	$	9,236,754	$	7,321	0.08%	0.00000
Dec-08	$	11,364,844	$	157,390	1.38%	0.00004
Jan-09	$	9,589,360	$	67,841	0.71%	0.00002
Feb-09	$	9,301,276	$	65,027	0.70%	0.00002
Mar-09	$	9,116,584	$	384,076	4.21%	0.00010
Apr-09	$	9,657,360	$	428,054	4.43%	0.00013
May-09	$	8,707,682	$	854,757	9.82%	0.00026
Jun-09	$	5,200,532	$	335,260	6.45%	0.00010
FYE09	$	97,632,650	$	2,365,322	2.42%	0.00005

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-09	$ 4,415,900	$ 17,809	0.40%	0.00000
Aug-09	$ 5,166,096	$ 81,725	1.58%	0.00002
Sep-09	$ 4,536,909	$ 38,172	0.84%	0.00001
Oct-09	$ 6,681,288	$ 96,615	1.45%	0.00003
Nov-09	$ 8,659,367	$ 398,315	4.60%	0.00012
Dec-09	$ 6,168,879	$ 21,765	0.35%	0.00001
Jan-10	$ 8,659,367	$ 15,380	0.18%	0.00000
Feb-10	$ 6,168,879	$ 43,617	0.71%	0.00001
Mar-10	$ 9,796,100	$ 130,620	1.33%	0.00004
Apr-10	$ 10,043,080	$ 318,281	3.17%	0.00010
May-10	$ 9,458,060	$ 189,651	2.01%	0.00006
Jun-10	$ 6,363,014	$ -	0.00%	0.00000
FYE10	$ 86,116,937	$ 1,351,950	1.57%	0.00003
Jul-10	$ 5,889,422	$ 30,218	0.51%	0.00001
Aug-10	$ 7,999,951	$ 1,118,405	13.98%	0.00026
Sep-10	$ 8,204,135	$ 755,635	9.21%	0.00023
Oct-10	$ 8,956,519	$ 90,191	1.01%	0.00003
Nov-10	$ 10,639,220	$ 18,314	0.17%	0.00001
Dec-10	$ 8,262,040	$ 67,164	0.81%	0.00002
Jan-11	$ 8,685,186	$ 8,352	0.10%	0.00000
Feb-11	$ 11,805,336	$ 57,676	0.49%	0.00002
Mar-11	$ 9,357,485	$ 40,590	0.43%	0.00001
Apr-11	$ 10,904,234	$ 39,573	0.36%	0.00001
May-11	$ 12,596,208	$ 23,328	0.19%	0.00001
Jun-11	$ 8,578,212	$ 61,634	0.72%	0.00002
FYE11	$ 111,877,948	$ 2,311,080	2.07%	0.00005

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-11	$ 4,505,969	$ -	0.00%	0.00000
Aug-11	$ 4,423,991	$ -	0.00%	0.00000
Sep-11	$ 5,797,516	$ 89,862	1.55%	0.00003
Oct-11	$ 11,041,598	$ 286,768	2.60%	0.00009
Nov-11	$ 13,146,681	$ 119,855	0.91%	0.00004
Dec-11	$ 11,628,278	$ 119,830	1.03%	0.00003
Jan-12	$ 13,985,009	$ 116,974	0.84%	0.00003
Feb-12	$ 10,356,745	$ 165,746	1.60%	0.00005
Mar-12	$ 13,410,686	$ 803,846	5.99%	0.00024
Apr-12	$ 13,309,148	$ 165,777	1.25%	0.00005
May-12	$ 12,620,061	$ 10,936	0.09%	0.00000
Jun-12	$ 10,014,738	$ 391,704	3.91%	0.00011
FYE12	$ 124,240,420	$ 2,271,297	1.83%	0.00005
Jul-12	$ 6,814,010	$ 33,320	0.49%	0.00001
Aug-12	$ 7,042,214	$ 2,177	0.03%	0.00000
Sep-12	$ 8,726,353	$ 70,346	0.81%	0.00002
Oct-12	$ 13,725,930	$ 60,073	0.44%	0.00002
Nov-12	$ 13,638,084	$ 283,709	2.08%	0.00008
Dec-12	$ 11,980,060	$ 237,727	1.98%	0.00007
Jan-13	$ 16,362,894	$ 99,847	0.61%	0.00003
Feb-13	$ 13,103,475	$ 77,831	0.59%	0.00002
Mar-13	$ 13,738,928	$ 241,879	1.76%	0.00007
Apr-13	$ 15,328,869	$ 780,565	5.09%	0.00025
May-13	$ 15,172,233	$ 443,050	2.92%	0.00014
Jun-13	$ 11,398,702	$ 270,229	2.37%	0.00008
FYE13	$ 147,031,752	$ 2,600,753	1.77%	0.00006

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-13	$ 9,648,075	$ 62,077	0.64%	0.00002
Aug-13	$ 7,432,793	$ 16,047	0.22%	0.00000
Sep-13	$ 13,324,529	$ 1,789,352	13.43%	0.00051
Oct-13	$ 17,161,880	$ 4,047,551	23.58%	0.00123
Nov-13	$ 19,904,761	$ 1,874,343	9.42%	0.00057
Dec-13	$ 14,469,307	$ 1,838,978	12.71%	0.00051
Jan-14	$ 21,642,583	$ 1,728,478	7.99%	0.00047
Feb-14	$ 17,428,740	$ 1,176,363	6.75%	0.00035
Mar-14	$ 18,119,605	$ 1,235,263	6.82%	0.00035
Apr-14	$ 18,810,495	$ 1,314,113	6.99%	0.00042
May-14	$ 13,969,245	$ 213,649	1.53%	0.00007
Jun-14	$ 11,586,723	$ 463,822	4.00%	0.00013
FYE14	$ 183,498,736	$ 15,760,036	8.59%	0.00037

Attachment E3

Wind Curtailment Email

Ouanes, Samir (COMM)

From: Ouanes, Samir (COMM)
Sent: Tuesday, April 21, 2015 3:50 PM
To: Chow, John
Cc: Eilers, Rebecca D; Ouanes, Samir (COMM)
Subject: RE: Xcel Energy 2014 AAA - DOC IR 033

John,

I thought it would be helpful to put in writing what we discussed over the phone yesterday in response to your email below.

First, as mentioned below and based on my review of the record, it is clear that "almost all of the curtailments are code 3." This is the reason why I am fine with <u>Xcel limiting its response to DOC IR 33 to such curtailments</u>. While it may mean that "they were of economic or MISO initiated reasons," it is still Xcel's burden of proof to show the prudency of these costs. DOC IR 33 is designed to help Xcel complete the record so that the Commission can make an informed determination on the matter of the substantial increase in curtailment payments during FYE14.

Second, at this stage, I am not asking for or need to receive "tons of data" for my review. I was also not expecting that Xcel would need "one month or more" to respond to DOC IR 33; I would have expected Xcel to be prepared to address this issue. Given the substantial seven-fold increase in curtailment payments during FYE14, DOC IR 33 provides Xcel with directions essentially for an executive summary, explaining to the Commission why there was such a drastic increase in the cost of providing service and justifying the reasonableness of Xcel's actions. (It might help to think of these costs as non-fuel costs that increased seven-fold during a year when Xcel did not have a rate case, requiring justification to Xcel's management why the costs increased and hurt the Company's bottom line.)

To help Xcel accomplish this goal, DOC IR 33 requests Xcel to:

1) Identify and fully describe the events that resulted in the FYE14 curtailment payments. (Note that Xcel's initial filing in the FYE14 AAA docket appears to identify the following events: "work-related to a storm in July 2011, severe ice storm in April 2013 and emergency maintenance on several high-voltage transformers." Please provide dates for these events.)
2) Identify, for each such event, the curtailed wind facilities, the total FYE14 amount of curtailments (MWh) and curtailment payments ($) made to each of the curtailed facilities.
3) For each such event, explain in layman's terms why and how the event caused the need to curtail these specific wind facilities.
4) The other questions are designed to help Xcel explain whether Xcel could have been more proactive in alleviating the occurrence and/or consequences of each such events and whether Xcel could have used a lower cost option to address the specific need for curtailment as a result of each such events.

Third, I am fine with extending Xcel's response to DOC IR 33 from April 20, 2015 to April 30, 2015 if it means a better record for the Commission.

Ideally, Xcel would use the format of a narrative that would address concerns about the reasons for these higher costs and the preventive measures taken by the Company to keep overall costs down.

Finally, please feel free to call me if you have any questions.

Thanks,
Samir

Samir Ouanes, Ph.D.
Rates Analyst
Division of Energy Resources
Minnesota Department of Commerce
(651) 539-1831

From: Chow, John [mailto:john.chow@xcelenergy.com]
Sent: Monday, April 20, 2015 10:14 AM
To: Ouanes, Samir (COMM)
Cc: Eilers, Rebecca D
Subject: Xcel Energy 2014 AAA - DOC IR 033

Samir,
With regard to your above referenced data request on wind curtailment we are still working on the response. As we speak three colleagues from Power and Markets Operations are working on your requests. We had a check-in meeting last Friday to discuss the status. The Operations folks' concerned the numbers of events (could have more than one events in a given month) and the complexity of tracing hourly LMP prices at the time of curtailments involve long hours of work. They estimated to fully respond to your inquiry for all curtailments the efforts could take one month or more. Obviously you and I understand DOC AAA Comments is due on May 19th therefore it is unlikely you have the luxury of time to wait that long. Besides even if Operations colleagues come through with compressing the time requirements there will be tons of data for you to screen and analyze. To illustrate the magnitude I have highlighted the attached tables in yellow for months by wind PPAs that have curtailments. There are 129 months total and assume 5 curtailment events per day there are over 600 events. To be honest if you look at the curtailment code, almost all of the curtailments are code 3, which means they were of economics or MISO initiated reasons. With that said I wonder if you agree with my proposal to simplify the IR-033 from all events to curtailment months to a selected numbers of months. My selection criteria include any months curtailment codes other than 3 and % of curtailment payment is over 50% of total payments (delivered energy and curtailment payments). I have highlighted my proposed selection in blue. Please let me know if this is a workable compromise. Feel free to call or e-mail me your comments or alternative suggestions.

Thanks.
John

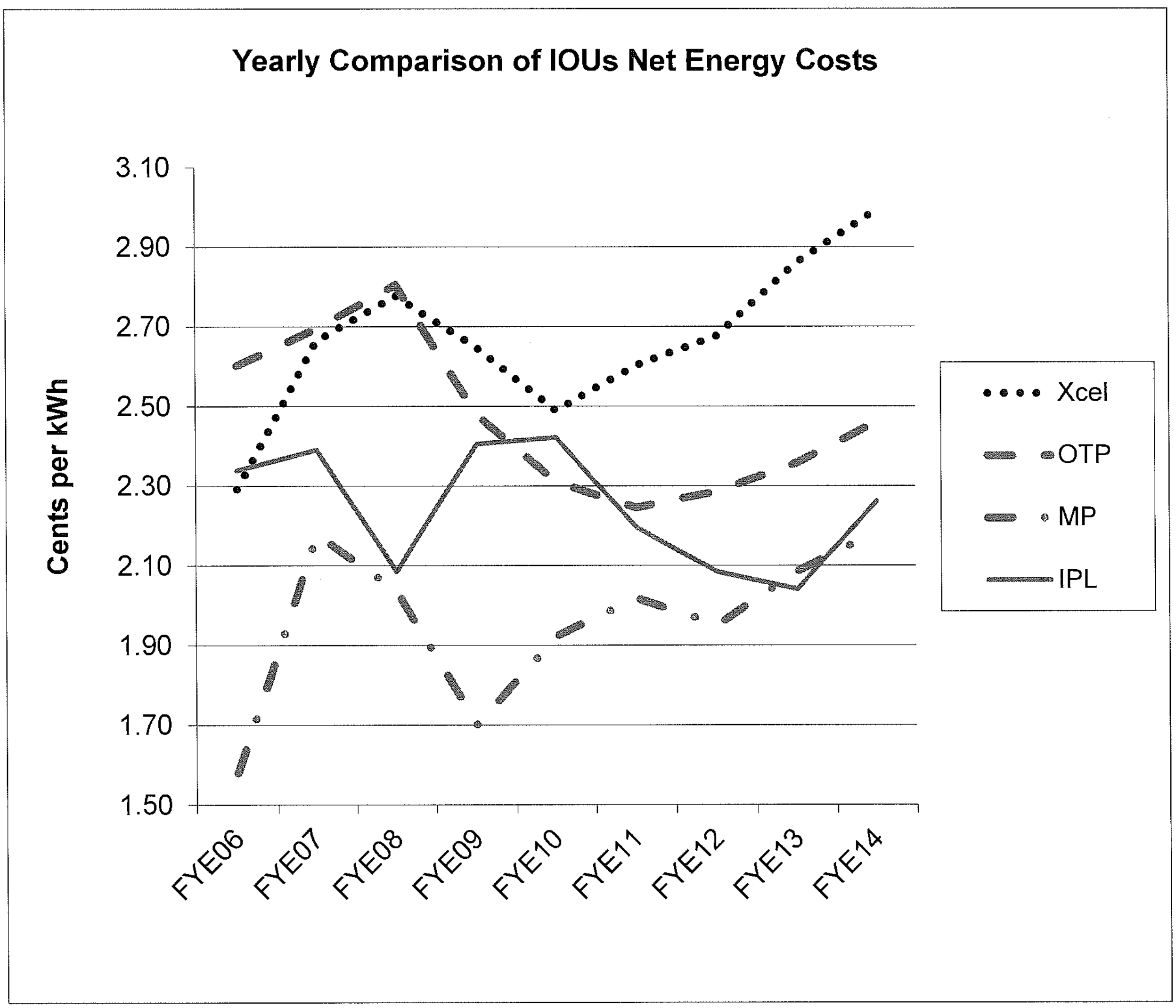
612-330-7588

Attachment E4

Annual Comparison of IOUs Net Energy Costs and Outages Costs: FYE06 through FYE14

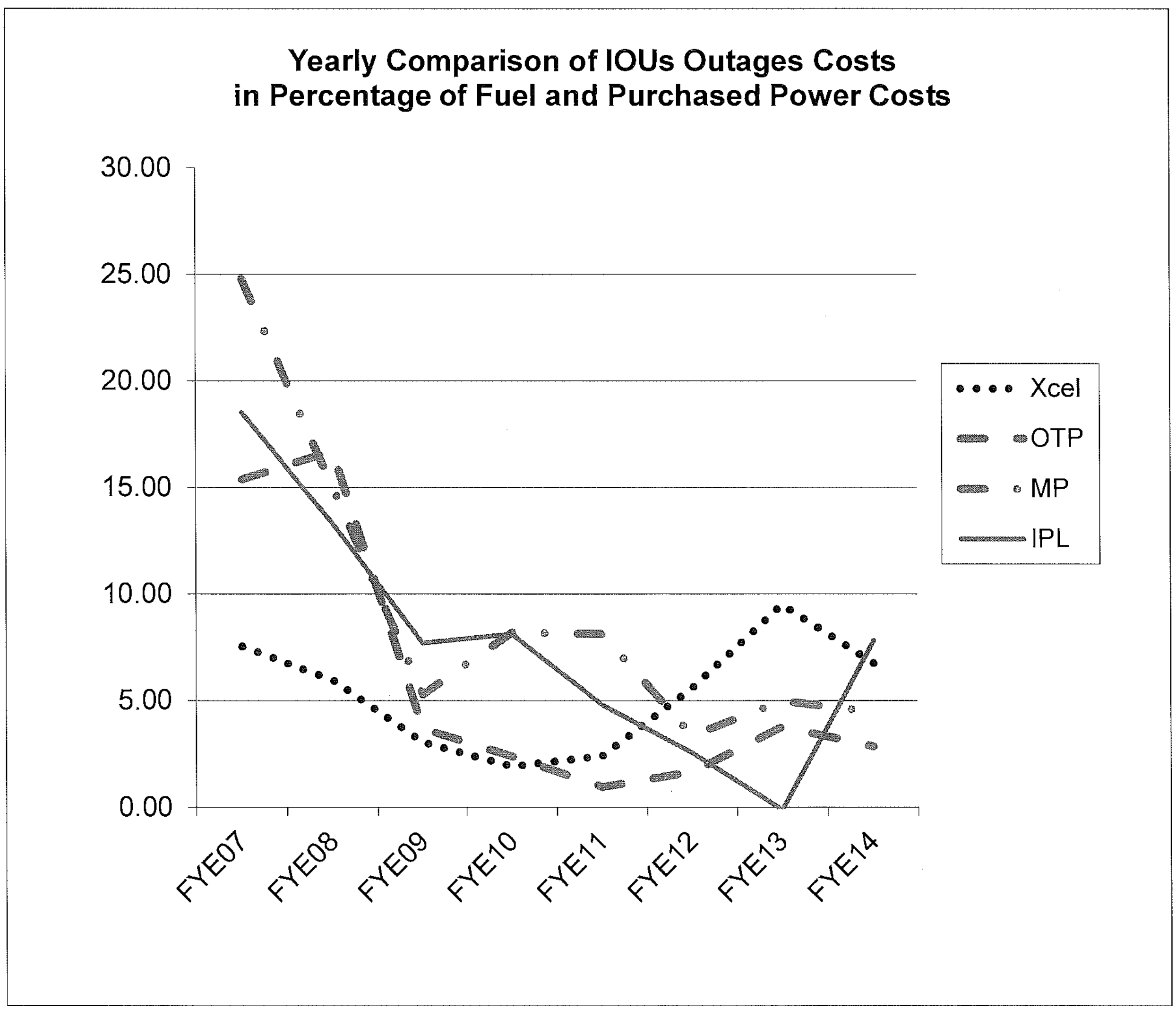
Utilities Fuel and Purchased Power Costs in cents per kWh

Cents/kWh	Xcel	OTP	MP	IPL
FYE06	2.29	2.60	1.58	2.34
FYE07	2.66	2.69	2.18	2.39
FYE08	2.78	2.81	2.04	2.09
FYE09	2.65	2.48	1.70	2.41
FYE10	2.49	2.31	1.92	2.42
FYE11	2.60	2.24	2.02	2.20
FYE12	2.68	2.29	1.95	2.08
FYE13	2.86	2.36	2.09	2.04
FYE14	2.99	2.46	2.19	2.26
Min	2.29	2.24	1.58	2.04
Max	2.99	2.81	2.19	2.42



Utilities Outages Costs in Percentage of Fuel and Purchased Power Costs

%	Xcel	OTP	MP	IPL
FYE07	7.55	15.38	24.80	18.51
FYE08	5.97	16.70	15.02	13.32
FYE09	3.06	3.70	5.29	7.71
FYE10	1.92	2.38	8.20	8.12
FYE11	2.41	0.95	8.12	4.81
FYE12	5.60	1.66	3.37	2.56
FYE13	9.50	3.77	4.99	-0.11
FYE14	6.77	2.86	4.48	7.83
Min	1.92	0.95	3.37	-0.11
Max	9.50	16.70	24.80	18.51



Attachment E5

IOUs Maintenance Expenses of Generation Plants: 2005-2013

FYE14 AAA

Maintenance Expenses of Generation Plants

	Docket/ Test Year	Rate Case (a)	2006	2007	2008	2009	2010	2011 (b)	2012 (c)	2013 (d)
IPL	10-276/2009	$ 3,779,345	$ 2,737,232	$ 2,906,925	$ 3,834,111	$ 3,015,487	$ 3,173,210	$ 3,593,908	$3,405,372	$3,163,487
MP	09-1151/2010	$ 33,619,194	$ 29,556,035	$ 34,498,017	$ 29,819,678	$ 29,031,118	$ 45,307,981	$ 45,683,871	$42,970,316	$36,565,651
Xcel	13-868/2014	$ 193,685,565	$138,916,698	$144,317,233	$128,411,240	$150,857,274	$169,389,054	$179,143,695	$176,598,518	$196,531,281
OTP	10-239/2009	$ 13,142,720	$ 11,871,158	$ 10,444,219	$ 12,981,917	$ 12,911,918	$ 10,505,153	$ 12,014,142	$11,911,878	$11,415,197

3-year average (e)	Difference (f)
$ 3,387,589	$ (391,756)
$ 41,739,946	$ 8,120,752
$184,091,165	$ (9,594,400)
$ 11,780,406	$ (1,362,314)

(e) = ((b) + (c) + (d))/3
(f) = (e) - (a)

Attachment E6

Otter Tail Power Company's response to DOC discovery related to rail delivery issues

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Coal Procurement Strategy

a. How does the utility forecast its coal needs?

b. Please explain the utility's strategy for purchasing coal to meet its anticipated needs with respect to the timing of coal purchases for its coal-fired plants. In other words, on January 1, 2014, what percentage of anticipated coal needs for 2014 did the utility have secured? As of January 1, 2014, what percentage of anticipated coal needs for *2015* did the utility have secured? Etc. To the extent there are plant-specific considerations, please explain them.

c. If a particular coal-fired plant were dispatched less than expected during a given year (and thus burned less coal than expected), would the utility attempt to adjust coal deliveries in real-time, or simply allow coal inventory to build up at the plant and adjust deliveries at a later date?

Attachments: 0

Response:

a. Otter Tail Power uses the Strategist modeling tool for forecasting its coal needs. Strategist starts with Otter Tail's customer load forecast. Then incorporates all of Otter Tail's generating resources (Owned units and Purchased Power Agreements), as well as, interaction with the MISO market. Strategist takes into account fuel heat content, plant heat rates, minimum run requirements, and planned outages when calculating the quantity of coal to be consumed over a given time period.

b. Historically, Otter Tail's strategy for procuring coal has been to secure a significant portion of a plant's coal supply under a forward contract to insure both supply availability and price certainty for a majority of the plant's supply needs. The remaining amount of coal needed for the balance of the year is assessed in the late summer time frame (after summer peak demand time period has passed) and remaining supply needs are secured or

adjusted following assessment of how actual generation levels are matching with forecast or budgeted levels and expectations for the balance of the year. Contracts sometimes include take or pay provision that dictate how much is initially contracted. Other contracts have allowed for purchases to be carried forward to the subsequent year in the event generation levels are lower than originally budgeted. Otter Tail has never had a concern about having adequate supplies available from its coal suppliers. Specific characteristics of Big Stone and Hoot Lake supply contracts are noted below.
At Big Stone Plant, on January 1, 2014, we had approximately 80-90% of the 2014 and 2015 budgeted coal use under contract. As the year advanced, we added an additional amount to one contract and then rolled the unused coal into 2015.

At Big Stone Plant, on January 1, of 2015, we had approximately 80-90% under contract for both 2015 and 2016. Currently, for 2015, Big Stone has approximately 104% of forecasted coal under contract, with the flexibility to roll over the unused amount into 2016.

At Hoot Lake Plant, as of January 1, 2014, we had approximately 100% of our expected needs under contract, but we had flexibility in that our commitment had an "up to" provision, so that we would not end up short or long as the provisions provide flexibility. We also had about 60 – 70% of the coal under contract for 2015. We have also at times negotiated carry-forward provisions in our contracts to provide flexibility to move tons into a future year if actual generation levels fall short of budget.

Coyote Station is a mine mouth plant.

c. The risk of having coal commitments in excess of coal needs due to reduced generation is mitigated to a degree by not committing to 100% of coal needs until later in a given year. Even with that approach, if generation was less than forecast and on-site inventories were at full levels, we could look to push the excess coal in the current year to a future year.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Strategy for Procuring Rail Transportation of Coal

a. Please provide a general discussion describing the utility's strategy for procuring rail transportation for coal, and how that strategy relates to the utility's strategy for procuring coal. Please address the following questions, but also provide any other relevant information.

b. Is it the utility's goal to transport all of its coal via multi-year rail transportation contracts? Or does the utility rely on rail contracts for only a portion of its coal transportation needs, and rely on shorter-term solutions for a portion (e.g. rail transportation at tariffed, common carrier rates).

c. Are coal deliveries by rail to each coal-fired plant governed by separate rail contracts? Or can one contract cover deliveries to multiple plants?

d. For each plant, does the utility typically have one rail transportation contract in place at a time? Or are plants served under multiple rail transportation contracts with differing terms (e.g. volumes and expiration dates)?

e. How does the utility's procurement of rail transportation accommodate changes to its forecasted coal needs?

Attachments: 0

Response:

a. Big Stone Plant and Hoot Lake Plant are captive rail customers and are subject to the BNSF tariff for rail service to each plant. Otter Tail communicates monthly to the BNSF the estimated monthly levels of coal delivery service for each plant. As part of the Tariff at each plant, there is a minimum annual level that must be met or the shipping rate increases for every ton delivered in that year. Otter Tail's Coyote Plant is a mine-mouth plant.

b. All rail shipments to Big Stone Plant and Hoot Lake Plant are under tariff.

c. All rail shipments to Big Stone Plant and Hoot Lake Plant are under tariff.

d. All rail shipments to Big Stone Plant and Hoot Lake Plant are under tariff.

e. All rail shipments to Big Stone Plant and Hoot Lake Plant are under tariff.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Rail Contracts

a. Please provide copies of all rail transportation contracts the utility has been party to at any time since the January 1, 2011 (including contracts that were signed prior to January 1, 2011, but still in effect on that date).

b. Please describe, in non-technical terms, the terms of the contracts provided in response to part (a), including pricing, annual volumes, the responsibilities of the rail carriers, the responsibilities of the utility, etc.

c. Please explain whether the contracts provided in response to part (a) govern *all* coal deliveries by rail to the utility's plants, or if any coal gets delivered by rail pursuant to any other transactions or agreements?

Attachments: 2

Attachment_1_toIR-MN-DOC-023_BNSF-90062Arev20eff01-09-15BigStonePlant_PUBLIC.pdf
Attachment_2_toIR-MN-DOC-023_BNSF-90074rev18eff01-09-15HootLakePlant_PUBLIC.pdf

Response:

a. Big Stone Plant and Hoot Lake Plant are under BNSF tariff. OTP is not certain whether the tariff to Big Stone and Hoot Lake is confidential information. We have contacted the BNSF with regards to the confidentiality of the Tariff document but have not received confirmation back from BNSF at this time. Therefore, we are marking Attachments 1 and 2 to MN-DOC-023 (Big Stone and Hoot Lake Tariffs) as Trade Secret.

b. The tariff governance is very straightforward. There is a specific cost per loaded railcar to each site from a particular coal mine or set of coal mines. The tariff sets a minimum annual volume for each plant. If the minimum annual volume is not met, the plant is subject to an increased rate for each ton delivered in that year. Other provisions relate to minimum freight charges and weight limits, loading and unloading of cars, billing, and other applicable tariffs, rules and regulations.

c. The tariffs are specific to each plant and cover all coal deliveries.

BNSF RAILWAY COMPANY
COMMON CARRIER PRICING AUTHORITY BNSF 90062-A
Revision 20

[TRADE SECRET DATA BEGINS...

THIS ATTACHMENT IS TRADE SECRET IN ITS ENTIRETY

...TRADE SECRET DATA ENDS]

BNSF Railway Company
Common Carrier Pricing Authority BNSF 90074
Revision 18

[TRADE SECRET DATA BEGINS...

THIS ATTACHMENT IS TRADE SECRET IN ITS ENTIRETY

...TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Rail Deliveries

a. For each of the contracts provided in response to the prior Information Request, please provide the utility's desired level of deliveries each year. If a contract required (or requires) the utility to nominate a specific level of deliveries for a calendar year prior to the start of that calendar year, please provide the nominated amount of deliveries, and explain how the nominated amount was derived.

b. Please provide actual deliveries pursuant to each contract by month since January 2011.

c. Please provide actual coal deliveries to each of the utility's coal plants by month since 2011.

d. If the delivery data provided in response to part (c) does not reconcile with the delivery data provided in response to part (b), please explain why.

Attachments: 0

Response:

a. Shipment of coal to Big Stone Plant and Hoot Lake Plant are under Tariff and not contracts. The utility forecasts the amount of coal that will be shipped to each plant to the BNSF on a monthly basis. Per the Tariff, there is an annual minimum level of coal delivery that must be met or the shipping costs are adjusted to a higher rate.

b. Coal delivery data for the Big Stone Plant and Hoot Lake Plant is included in Attachment 1 of Otter Tail's response to MN-DOC-028 information request in this Docket.

c. The information from b and c is identical.

d. The information from b and c is identical.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Railroad Performance

a. Please explain whether, under the terms of each of the utility's rail transportation contracts, the railroad has met its delivery obligations.

b. Please explain whether any railroads have faced any penalties, financial or otherwise, pursuant to a contract with the utility. If any railroads have paid a financial penalty, please explain whether this penalty was credited to ratepayers via the fuel clause adjustment.

c. If the railroads have met their delivery obligations as specified in the contracts, please explain why coal inventories were or are low.

Attachments: 0

Response:

a. Shipments to our coal plants are under Tariff and not contract. The Tariff does not specify a minimum level of service or performance by the railroad.

b. OTP is not aware of any penalties, financial or otherwise applicable to the BNSF under the Tariff.

c. As noted above, the Tariff does not specify a minimum level of service or performance by the railroad. Due to long cycle times and limited ability by the railroads to deliver coal in a timely manner, OTP used available coal stockpiles to continue operations at

Big Stone Plant until those stockpiles reached levels where the joint owners of the Big Stone Plant implemented their coal conservation policy (See OTP's response to Information Request MN-DOC-26 for discussion on Coal Conservation Policy) from mid-June until December 2014 to conserve coal inventories ahead of the 2014/2015 winter peak demand season.

Coal inventory levels at OTP's Hoot Lake Plant did drop as cycle times for deliveries were delayed. However no conservation measures were required at that plant.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Impacts of Delivery Delays

a. Please provide a detailed discussion of any coal transportation delays the utility has experienced since January 1, 2013, and the impacts those delays have had on the utility's coal inventories.

b. Please describe any actions the utility has undertaken to conserve coal in response to any coal transportation delays it has experienced.

c. If the utility limited production at any of its coal plants in order to conserve coal, please specifically explain how the Company achieved this reduction (e.g. a change in the plant's offer price in the MISO market, an artificial limit on available capacity, etc.).

d. If the utility limited production at any of its coal plants in order to conserve coal, please explain why the utility thought this action was necessary, and provide copies of any and all analyses the utility relied upon in deciding to limit energy production (e.g. quantitative or qualitative cost-benefit analyses, etc.). If the utility was concerned that a plant's coal inventory would fall below a predetermined minimum, please explain how the minimum inventory was determined.

e. Please state whether the coal conservation efforts described in response to parts (b) and (c) have ended or are ongoing.

f. To the extent that the utility reduced production at its coal plants, please estimate the incremental costs associated with the replacement energy purchased from the MISO market or produced at one of the utility's other generating plants.

g. To the extent that the utility reduced production at its coal plants, please explain any steps the utility took to protect ratepayers from higher costs associated with the replacement energy. If the utility took no steps, please explain why.

Attachments: 0

Response:

a. Beginning at the end of 2013 and continuing into 2014, the railroad was not able to meet the coal delivery demand to the Big Stone Plant. There were two primary reasons for this. The cycle times from the plant to the mine had increased and the BNSF removed one train set from service, because of the congestion on the rail lines. As a result of longer cycle times and limited train availability, the stockpile (inventory) levels began to drop below acceptable levels. Big Stone Plant is a co-owned facility and as a result of low inventory levels, the co-owners made a decision to restrict plant output, generally during off-peak periods, to conserve coal until the inventory levels could be restored.

b. The co-owners of the Big Stone Plant collectively agreed to limit output of Big Stone primarily in the off-peak hours to conserve coal inventories. The description of how OTP met this is in (g) below.

c. Explained in (g) below.

d. As a result of coal delivery issues at Big Stone Plant in 2006, the Big Stone owners developed and implemented a coal conservation policy, to set power plant reductions to conserve fuel supply. The purpose of the policy was to formalize the process by which the owners would decide to take action to reduce the possibility that the Big Stone Plant would not be available for on-peak periods, long periods, or emergency periods (such as potential natural disasters that could greatly reduce coal deliveries further). The triggers for beginning and ending coal conservation activity were set based on the judgment of the owners and plant staff of what measures could reasonably be expected to return the plant to normal stockpile levels. There have not been material changes to these thresholds since they were originally set.

e. Coal Conservation efforts as described in response to parts (b) and (c) have ended.

f. Incremental costs associated with the replacement energy are estimated to be between $800k and $1 million (OTP total system basis). OTP estimated this by analyzing hourly load and resource data during 2014, comparing actual generation to actual load to see if OTP was short resources to cover load. If short, we analyzed if typical operation of Big Stone Plant would have covered at least a portion if not all of the load. Using the lower of either the LMP price, or the cost of generation for Big Stone, we estimated the costs identified above, only including those hours where operating the plant at a higher level would have been more economical than simply purchasing from the market. While the detailed analysis only focused on the June-December 2014 timeframe, because there was some intermittent coal conservation measures implemented in 2013 as well, we provided a range estimate for the collective cost associated with coal conservation measures.

g. OTP did reduce production for its share at Big Stone Plant, and took steps to protect ratepayers from higher costs associated with the replacement energy by modifying its market offers. In general, OTP's share of the plant's minimum was offered as must run for all hours. On-peak hours, above OTP's share of minimums up to its maximum capability were offered at the plant cost. This is a normal course of business and does not represent a conservation effort.While intermittent periods of coal conservation at Big Stone Plant during the calendar year of 2013 were observed during the review of operations in preparation to respond to these inquiries, the conservation efforts became largely amplified during mid-year 2014. The responses here outline this most recent conservation effort. Similar actions were taken in preceding instances. Beginning on June 19, 2014, during off-peak hours, OTP's share of the plant between maximum capability and minimums was offered to the market at an artificially high price that was set just high enough that the unit would not be expected to clear the market. As per our coal conservation policy, the IMM was notified of this change in offer price. This represents OTP's effort to conserve coal and protect its ratepayers from high costs of replacement power. Historically, off-peak LMPs have been less valuable than on-peak LMPs. By raising the offer price during off-peak hours, OTP effectively backed the unit down using less coal during times when loads are generally down and prices are generally softer. Since the unit remained available to MISO for system stability events and/or LMP prices in excess of the offer price, the ratepayers were protected from prices in excess of the artificially high offer price. Later, a weekly energy target was imposed to each of the Big Stone Plant participants based on their ownership share. It was designed to provide the same levels of coal conservation as the previous on-peak scheduling at maximum load, but shifting to a weekly energy target gave an owner the flexibility to offer the unit into the market at its maximum capability outside of the typical on-peak hours to help minimize replacement power costs, as long as it stayed within the weekly energy target for the week. OTP reviewed its offer prices from time to time to make sure they were set at a level that was slightly above what would be expected to clear the market in order to balance the goals of coal conservation and minimizing our customers' exposure to excessive replacement power costs.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
Date Due: 03/30/2015
Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Rail Delivery Improvements

a. If the utility is working directly with railroads to improve delivery times in the short and medium terms, please explain the nature of these efforts. Please specifically explain what options are available to the railroad to improve delivery times in the short and medium term.

b. Please provide the utility's perspective on when and how its rail delivery issues will be fully resolved, and its expectations for rail service for the next few years.

c. Please explain whether the utility plans to alter its coal transportation and procurement strategies in the future in response to any delays it has experienced (i.e. higher inventories, higher transportation volumes, different performance requirements for railroads, larger penalties for railroads, etc.).

Attachments: 1

Attachment 1 to IR MN-DOC-027.pdf

Response:

a. Utility representatives have communicated frequently with the railroad to indicate the gravity of the situation and importance of meeting coal deliveries to the generating facilities. In addition, OTP sent a letter to the STB indicating its level of concern and dissatisfaction with the Burlington Northern Santa Fe (BNSF) on September 11, 2014 (Attachment 1 to MN-DOC-027). We do not know the options available to the railroad to improve delivery times in the short and medium term. Since the period in 2014 when the Big Stone Plant coal conservation measures were put in place, the BNSF has placed the third train set into service and cycle times improved to the point where coal conservation measures were removed in December 2014.

b. Coal conservation restrictions were removed at Big Stone Plant (end of 2014). While coal delivery cycle times have improved in 2015, we will need to see consistent improvement in service for an extended period of time before we will be confident that the rail delivery issues have been completely resolved.

c. The Big Stone Plant co-owners have discussed raising inventory levels. There is no plan to modify transportation strategies as the Big Stone Plant and Hoot Lake Plant are under Tariff.

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September 11, 2014

OTTER TAIL POWER COMPANY

BY E-FILING

Ms. Cynthia Brown
Chief, Section of Administration
Office of Proceedings
Surface Transportation Board
395 E Street, S.W.
Washington, DC 20423-0111

Dear Ms. Brown:

Re: Docket No. EP 724, *United States Rail Service Issues*
Comments of Otter Tail Power Company

This letter provides Otter Tail Power Company's written comments in the above-referenced matter. We request that they be included in the docket record.

As President of Otter Tail Power Company, I am writing to express my increasing concern about the Burlington Northern Santa Fe's inability to deliver sufficient coal to our Big Stone Plant at Big Stone City, South Dakota. My company is the operating agent for this 475-MW plant that we own jointly with Montana-Dakota Utilities Co. and NorthWestern Energy. The plant has single carrier rail service from the BNSF.

Big Stone Plant implemented coal-conservation measures on June 19, 2014, in response to declining stockpile levels. The plant owners decided to curtail the plant's generation voluntarily in an effort to conserve coal. This was not an easy decision to make because it can expose our customers to higher-cost replacement energy. In June BNSF indicated that its service should improve after the Fourth of July holiday weekend. This improvement--which we measure in cycle time, or the time it takes for a train to run from the plant to the mine and back to the plant--did not occur. In fact, we have not seen any consistent signs of improvement all summer. Current cycle times from the BNSF are 70 percent higher than what they should be, with our trains parked for extended periods of time during their trips to and from the Powder River Basin.

These longer cycle times mean that BNSF is not able to deliver the coal needed to keep the plant operating at full load and with normal stockpile levels. The plant provides monthly forecasts to the BNSF for its coal needs for the next month. During the last 12 months the BNSF has delivered only 80 percent of what the plant has forecasted, forcing the plant to go into its emergency stockpile to make up for the shortfall in deliveries. While some plants have stockpiles that were designed for frequent access, Big Stone's inactive coal stockpile was designed for true emergencies, such as a bridge failure on the rail system that would impact deliveries for an extended period or a coal-delivery system failure at the plant, etc. Unfortunately, Big Stone has been pressed into using its coal stockpile to meet daily operational needs. This is an inefficient, labor-intensive effort that results in higher costs for our customers.

While there has been a great focus on BNSF service issues in this past year, it is important to note that Big Stone Plant has experienced coal-delivery issues on and off for the last decade. In fact, it has implemented coal conservation five times in the last eight years. This is not just a recent phenomenon.

What is equally concerning is that the true severity of the current situation is being masked not only by the moderate summer weather but also by the actions taken by the utility coal shippers themselves—primarily coal conservation but also hauling coal by truck and switching to alternate fuels. These actions, intended to protect our customers' interests in the long term, not only come at higher cost to customers but also enable the BNSF to be more confident in its claims that it will not allow plants to run out of coal.

We have had success in the past working with the BNSF through enhanced communication and coordination at various levels. Through these measures we have managed to avoid single-digit stockpile levels that other plants have reported. However, we remain at below-normal stockpile levels with no relief in sight. We estimate that coal conservation this summer has reduced the output of the plant by up to 20 percent. If our coal conservation would have been coupled with improved service from the BNSF, we would have expected to see stockpile levels rise to the point where coal conservation no longer would be necessary. But this has not happened, and it is greatly concerning as we head into what possibly could be a record grain harvest and our winter peak season.

Otter Tail Power Company respectfully requests that the Board take action now to remedy this situation. The evidence shows that doing nothing is no longer an acceptable option. About a year ago the BNSF acknowledged that they did not deliver on service in 2013 and needed to do better. The BNSF presented a plan for 2014 to remedy the situation. It has not resulted in service improvements as of yet, nor is it expected to anytime soon because the BNSF has indicated that this situation is expected to continue into 2016. The BNSF needs to restore cycle times to normal levels. Measures need to be put in place to allow an assessment of BNSF's progress toward restoring coal delivery service.

Respectfully submitted,

Tim Rogelstad
President
Otter Tail Power Company

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Craig Addonizio
Date Received: 03/18/2015
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Date of Response: 03/30/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Coal Consumption and Inventories

a. Please provide actual coal consumption by month at each of the utility's plants.

b. Please provide actual coal inventories by month at each of the utility's plants.

c. Please provide the desired coal inventory level for each of the utility's plants.

d. Please explain the reasoning behind the desired level of coal inventory for each of the utility's plants. Please explain any plant-specific considerations that influence the desired inventory.

Attachments: 1

Attachment 1 to IR-MN-DOC-028.pdf

Response:

a. This is provided in Attachment 1 to IR MN-DOC-028.

b. This is provided in Attachment 1to IR MN-DOC-028.

c. Our desired inventory in the Big Stone Plant stockpile has been 30 days of inventory (210,000 tons). Our desired inventory level at Hoot Lake Plant has been 20 days of coal (33,750 tons). In recent years, the decision has been made to increase the stockpile levels in advance of the winter peak season to 35 – 38 days at Big Stone Plant and 25 days at Hoot Lake Plant.

d. Maintaining sufficient coal stockpiles at Big Stone Plant and Hoot Lake Plant provides protection against the possibility that the plants wouldn't be available for on-peak periods, long periods, or emergency periods (such as potential natural disasters that could reduce coal deliveries) due to lack of fuel. The desired stockpile levels have been developed over time and have been adequate to meet the needs of the facilities.

	BSP Delivered (tons)	BSP Burned (tons)	Approx desired stockpile inventory (tons) 210,000 BSP Mnth end Inv. (tons)
Jan-11	135,918	205,825	242,311
Feb-11	150,430	162,742	229,999
Mar-11	185,082	189,232	225,849
Apr-11	153,336	154,086	225,099
May-11	141,661	158,748	208,012
Jun-11	112,596	157,485	163,123
Jul-11	184,007	194,162	152,968
Aug-11	184,240	157,019	180,189
Sep-11	70,560	67,352	183,397
Oct-11	56,055	-	239,452
Nov-11	83,190	39,365	283,277
Dec-11	219,003	162,447	339,833
TOTAL	1,676,078	1,648,463	
Jan-12	121,432	156,187	305,078
Feb-12	109,394	119,207	295,265
Mar-12	138,863	122,143	311,985
Apr-12	70,894	119,368	263,511
May-12	111,040	151,867	222,684
Jun-12	110,831	101,047	232,468
Jul-12	197,513	183,888	246,093
Aug-12	178,803	182,309	242,587
Sep-12	226,199	180,875	287,911
Oct-12	166,909	191,702	263,118
Nov-12	178,590	164,536	277,172
Dec-12	202,309	198,963	280,518
TOTAL	1,812,777	1,872,092	
Jan-13	190,176	199,598	271,096
Feb-13	131,770	159,681	243,185
Mar-13	178,993	179,865	242,313
Apr-13	135,771	140,016	238,068
May-13	42,410	82,345	198,133
Jun-13	153,929	150,490	201,572
Jul-13	194,584	155,531	240,625
Aug-13	155,449	179,167	216,907
Sep-13	156,224	142,306	230,825
Oct-13	112,834	121,871	221,788
Nov-13	151,427	169,482	203,733
Dec-13	184,127	166,721	221,139
TOTAL	1,787,694	1,847,073	
Jan-14	150,654	151,288	220,505
Feb-14	166,830	157,806	229,529
Mar-14	174,738	185,673	218,597
Apr-14	183,898	156,430	246,062
May-14	112,199	118,921	239,340
Jun-14	99,358	166,951	171,747
Jul-14	152,149	147,957	175,939
Aug-14	153,140	138,377	190,702
Sep-14	155,905	129,729	216,878
Oct-14	167,391	135,813	248,456
Nov-14	82,897	133,124	198,229
Dec-14	176,926	158,302	216,853
TOTAL	1,776,085	1,780,371	
Jan-15	212,126	172,131	256,848
Feb-15	162,240	163,073	256,015
TOTAL	374,366	335,204	

	HLP Delivered (tons)	HLP Burned (tons)	Approx desired stockpile inventory (tons) 33,750 HLP Mnth end Inv. (tons)
Jan-11	26,655	45,291	23,402
Feb-11	54,930	39,526	38,807
Mar-11	55,014	42,640	51,181
Apr-11	27,715	32,232	46,663
May-11	41,377	33,873	54,168
Jun-11	28,551	36,462	46,257
Jul-11	41,310	48,437	39,130
Aug-11	55,712	46,684	48,158
Sep-11	41,679	38,609	51,228
Oct-11	26,881	41,055	37,054
Nov-11	41,974	39,385	39,642
Dec-11	42,422	41,652	40,412
	484,220	485,846	
Jan-12	56,556	39,802	57,166
Feb-12	27,119	30,759	53,526
Mar-12	28,243	30,012	51,757
Apr-12	14,021	13,994	51,784
May-12	14,455	20,053	46,186
Jun-12	42,404	39,541	49,049
Jul-12	42,989	43,336	48,703
Aug-12	42,985	39,125	52,563
Sep-12	28,912	30,044	51,431
Oct-12	28,927	36,102	44,257
Nov-12	42,575	41,488	45,344
Dec-12	55,591	44,330	56,605
	424,777	408,586	
Jan-13	41,422	44,216	53,812
Feb-13	40,818	40,939	53,691
Mar-13	25,973	43,518	36,146
Apr-13	39,608	34,020	41,734
May-13	42,703	34,739	49,697
Jun-13	42,894	39,926	52,665
Jul-13	42,668	44,736	50,598
Aug-13	42,265	42,843	50,020
Sep-13	43,249	42,082	51,187
Oct-13	28,516	43,803	35,900
Nov-13	42,035	41,330	36,604
Dec-13	53,962	49,437	41,129
	486,113	501,588	
Jan-14	39,234	49,156	31,208
Feb-14	53,028	45,778	38,458
Mar-14	41,976	45,249	35,185
Apr-14	14,168	10,832	38,521
May-14	14,136	1	52,657
Jun-14	13,213	(61)	65,931
Jul-14	14,371	20,186	60,115
Aug-14	28,640	27,562	61,193
Sep-14	28,417	37,478	52,131
Oct-14	41,595	41,577	52,149
Nov-14	40,579	41,878	50,851
Dec-14	41,516	44,046	48,321
	370,873	363,682	
Jan-15	42,143	33,580	56,884
Feb-15	14,247	25,593	45,537
	56,390	59,174	

Attachment E7

Interstate Electric's response to DOC discovery related to rail delivery issues

☐ **Confidential/Trade Secret**

Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 21

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Jim Dalton
Author's Title:	Mgr. Fuel Supply & Transport
Author's Telephone No.:	(608) 458-3375
Subject:	
Reference:	Coal Procurement Strategy

Information Request No. 21

a. How does the utility forecast its coal needs?

b. Please explain the utility's strategy for purchasing coal to meet its anticipated needs with respect to the timing of coal purchases for its coal-fired plants. In other words, on January 1, 2014, what percentage of anticipated coal needs for 2014 did the utility have secured? As of January 1, 2014, what percentage of anticipated coal needs for *2015* did the utility have secured? Etc. To the extent there are plant-specific considerations, please explain them.

c. If a particular coal-fired plant were dispatched less than expected during a given year (and thus burned less coal than expected), would the utility attempt to adjust coal deliveries in real-time, or simply allow coal inventory to build up at the plant and adjust deliveries at a later date?

Response:

a. IPL uses a forecasting model to develop projected annual generation levels for each generating unit in its system, including those coal-fired. The generation levels are determined based upon each unit's projected **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** relative to the associated **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**. One output of the model for each unit is the total amount of heat input (in trillions of Btu's) needed to produce the projected generation level. Each unit's annual burn quantity in tons is derived by dividing the annual total heat input by the heat content (mmBtu's) per ton of coal. The projected tonnage receipt levels for each unit/coal pile are based upon this information along with the corresponding coal pile's existing and projected desired inventory levels and the capacity of the associated rail equipment. A unit's forecasted total coal needs for a given calendar year equal the projected receipt level in tons. To the extent there are existing purchased quantities for a given year, such quantities reduce the coal needs remaining to be purchased.

b. Please see Confidential Attachment A, which shows, as of January 1, 2014, for calendar years 2014 and 2015 for each coal-fired plant, the anticipated coal needs (in tons), the tonnage then under contract and the percentage of the needs covered by the purchased quantity. **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]**.

c. If a plant's burn is reduced to a level below that expected, the action taken would depend upon a few different factors. For example, if the burn has been **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]**, coal deliveries to that plant would be adjusted **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** in real-time to match the desired receipt level, taking into consideration the then-existing inventory level relative to the desired level and/or the pile capacity. If, however, the burn has been **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]**, real-time **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** in coal deliveries to that plant might be limited to **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** unless there are reasons the pile **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** the corresponding level. If the real-time adjustments **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** in coal deliveries, deliveries to the impacted plant could be adjusted at a later point in time or, if the purchased coal **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]**.

TRADE SECRET

IPL Coal Needs & Purchases by Plant for 2014 & 2015

2014	Tons (ton nearest thousand)		
Plant	Coal Needs	Under Contract	% Secured
	[TRADE SECRET DATA BEGINS		
Burlington			
Kapp			
Lansing			
Ottumwa[1]			
Prairie Creek			
			TRADE SECRET DATA ENDS]

[1] Total Plant

2015			
	[TRADE SECRET DATA BEGINS		
Burlington			
Kapp[2]			
Lansing			
Ottumwa[1]			
Prairie Creek			
			TRADE SECRET DATA ENDS]

Confidential/Trade Secret

Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 22

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Nancy Chen
Author's Title:	Transportation & CCP Ops. Mgr.
Author's Telephone No.:	(608) 458-3194
Subject:	
Reference:	Strategy for Procuring Rail Transportation of Coal

Information Request No. 22

a. Please provide a general discussion describing the utility's strategy for procuring rail transportation for coal, and how that strategy relates to the utility's strategy for procuring coal. Please address the following questions, but also provide any other relevant information.

b. Is it the utility's goal to transport all of its coal via multi-year rail transportation contracts? Or does the utility rely on rail contracts for only a portion of its coal transportation needs, and rely on shorter-term solutions for a portion (e.g. rail transportation at tariffed, common carrier rates).

c. Are coal deliveries by rail to each coal-fired plant governed by separate rail contracts? Or can one contract cover deliveries to multiple plants?

d. For each plant, does the utility typically have one rail transportation contract in place at a time? Or are plants served under multiple rail transportation contracts with differing terms (e.g. volumes and expiration dates)?

e. How does the utility's procurement of rail transportation accommodate changes to its forecasted coal needs?

Response:

[TRADE SECRET DATA BEGINS

a. [redacted]

b.

c.

d.

e.

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

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Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 23

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Pat Jensen
Author's Title:	Senior Performance & Planning Analyst
Author's Telephone No.:	(608) 458-7631
Subject:	
Reference:	Rail Contracts

Information Request No. 23

a. Please provide copies of all rail transportation contracts the utility has been party to at any time since the January 1, 2011 (including contracts that were signed prior to January 1, 2011, but still in effect on that date).

b. Please describe, in non-technical terms, the terms of the contracts provided in response to part (a), including pricing, annual volumes, the responsibilities of the rail carriers, the responsibilities of the utility, etc.

c. Please explain whether the contracts provided in response to part (a) govern *all* coal deliveries by rail to the utility's plants, or if any coal gets delivered by rail pursuant to any other transactions or agreements?

Response:

a. IPL provides Trade Secret Attachment A to this information request response for copies of all rail transportation contracts that have been in effect since January 1, 2011.

b. IPL provides Trade Secret Attachment B to this information request response, which describes the contract terms, pricing, annual volumes, responsibilities of rail carrier and responsibilities of utility associated with each of the contracts provided in response to part (a) of this information request.

c. IPL provides Trade Secret Attachment B to this information request response, which also describes the contract provisions for coal deliveries associated with each of the contracts provided in response to part (a) of this information request.

[TRADE SECRET DATA BEGINS

ATTACHMENTS A & B
PUBLIC DOCUMENTS

TRADE SECRET DATA ENDS]

☐ **Confidential/Trade Secret**

Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 24

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Nancy Chen
Author's Title:	Transportation & CCP Ops. Mgr
Author's Telephone No.:	(608) 458-3194
Subject:	
Reference:	Rail Deliveries

Information Request No. 24

a. For each of the contracts provided in response to the prior Information Request, please provide the utility's desired level of deliveries each year. If a contract required (or requires) the utility to nominate a specific level of deliveries for a calendar year prior to the start of that calendar year, please provide the nominated amount of deliveries, and explain how the nominated amount was derived.

b. Please provide actual deliveries pursuant to each contract by month since January 2011.

c. Please provide actual coal deliveries to each of the utility's coal plants by month since 2011.

d. If the delivery data provided in response to part (c) does not reconcile with the delivery data provided in response to part (b), please explain why.

Response:

a. IPL provides Trade Secret Attachment A to this information request response which contains the utility's desired levels of deliveries by plant/transload facility for each year and each respective rail contract.

b. IPL provides Trade Secret Attachment B to this information request response which contains the utility's actual deliveries by plant/transload facility by month for each year and each respective rail contract since January 2011.

c. Please refer to Trade Secret Attachment B provided in this information request response for the actual coal deliveries to each of the utility's plant by month since January 2011.

[TRADE SECRET DATA BEGINS

ATTACHMENTS A & B
PUBLIC DOCUMENTS

TRADE SECRET DATA ENDS]

☐ **Confidential/Trade Secret**

Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 25

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Nancy Chen
Author's Title:	Transportation & CCP Ops. Mgr.
Author's Telephone No.:	(608) 458-3194
Subject:	
Reference:	Rail Performance

Information Request No. 25

a. Please explain whether, under the terms of each of the utility's rail transportation contracts, the railroad has met its delivery obligations.

b. Please explain whether any railroads have faced any penalties, financial or otherwise, pursuant to a contract with the utility. If any railroads have paid a financial penalty, please explain whether this penalty was credited to ratepayers via the fuel clause adjustment.

c. If the railroads have met their delivery obligations as specified in the contracts, please explain why coal inventories were or are low.

Response:
[TRADE SECRET DATA BEGINS

a. [redacted]

b. [redacted]

c. [redacted]

TRADE SECRET DATA ENDS]

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Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 26

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Nancy Chen
Author's Title:	Transportation & CCP Ops. Mgr.
Author's Telephone No.:	(608) 458-3194
Subject:	
Reference:	Impacts of Delivery Delays

Information Request No. 26

a. Please provide a detailed discussion of any coal transportation delays the utility has experienced since January 1, 2013, and the impacts those delays have had on the utility's coal inventories.

b. Please describe any actions the utility has undertaken to conserve coal in response to any coal transportation delays it has experienced.

c. If the utility limited production at any of its coal plants in order to conserve coal, please specifically explain how the Company achieved this reduction (e.g. a change in the plant's offer price in the MISO market, an artificial limit on available capacity, etc.).

d. If the utility limited production at any of its coal plants in order to conserve coal, please explain why the utility thought this action was necessary, and provide copies of any and all analyses the utility relied upon in deciding to limit energy production (e.g. quantitative or qualitative cost-benefit analyses, etc.). If the utility was concerned that a plant's coal inventory would fall below a predetermined minimum, please explain how the minimum inventory was determined.

e. Please state whether the coal conservation efforts described in response to parts (b) and (c) have ended or are ongoing.

f. To the extent that the utility reduced production at its coal plants, please estimate the incremental costs associated with the replacement energy purchased from the MISO market or produced at one of the utility's other generating plants.

g. To the extent that the utility reduced production at its coal plants, please explain any steps the utility took to protect ratepayers from higher costs associated with the replacement energy. If the utility took no steps, please explain why.

Response:

a. IPL didn't experience any significant delays in the rail transportation of coal at any IPL-managed facility that resulted in constraining the consumption of coal due to coal transportation delays.

b. No actions were taken due to the under delivery of coal because of any rail transportation system delay.

c. Due to the heavy burns experienced during the extreme cold weather ("polar vortex") of 2014 and the expected delay in the opening of the 2014 river navigation season due to weather conditions, IPL constricted the consumption of coal in the months of March and part of April to ensure the continuous reliable operation of Lansing Unit #4 for IPL customers. Lansing Unit #4 only receives coal through the river transportation system. The 2014 river navigation season did experience problems with flooding and the early closing of the season due to the cold fall weather greatly shortening the 2014 season. IPL used price dispatch adders exclusively to reduce the consumption of coal in low marginal periods. This strategy was used in the months of March, April, November and December of 2014. IPL used a varying dispatch adder between $5 and $10/MWHr to limit the consumption of coal only in low marginal periods where the potential margin was less than the dispatch adder.

d. IPL managed the coal consumption at our Lansing Unit #4 generating plant in the spring, fall and early winter of 2014 due to the under delivered coal from the shortened river navigation season that occurred in 2014 due to weather conditions. In combination with a heavy 2014 winter burn, along with the expectation of a late opening of the 2014 river navigation season, a small burn management plan was used to ensure Lansing Unit #4 didn't fall below 30 days of inventory at normal operations by the end of March 2014. The early closure of the 2014 river navigation season also resulted in IPL again implementing a burn management plan to ensure the continuous operations of Lansing Unit #4 until the start of the 2015 river navigation season. IPL uses a daily average burn to calculate a day's inventory on the ground.

e. Coal conservation has ended at Lansing.

f. IPL has estimated the total lost marginal opportunity in 2014 for all IPL rate payers (Iowa and Minnesota) due to coal conservation or burn management plan at Lansing #4 as less than $500,000.00 as a total. IPL doesn't look to replace the energy not produced but rather calculates the lost marginal opportunity of not producing the margin to offset load costs.

g. IPL felt that the strategy of only limiting the consumption of coal in low marginal hours for a few months in an effort to ensure the reliable and continuous operations didn't warrant any further steps to mitigate risk to IPL rate payers.

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Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 27

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Nancy Chen
Author's Title:	Transportation & CCP Ops. Mgr.
Author's Telephone No.:	(608) 458-3194
Subject:	
Reference:	Impacts of Delivery Delays

Information Request No. 27

a. If the utility is working directly with railroads to improve delivery times in the short and medium terms, please explain the nature of these efforts. Please specifically explain what options are available to the railroad to improve delivery times in the short and medium term.

b. Please provide the utility's perspective on when and how its rail delivery issues will be fully resolved, and its expectations for rail service for the next few years.

c. Please explain whether the utility plans to alter its coal transportation and procurement strategies in the future in response to any delays it has experienced (i.e. higher inventories, higher transportation volumes, different performance requirements for railroads, larger penalties for railroads, etc.).

Response:

a. Vigilance on the part of IPL operations staff is critical to ensuring that delivery times are leveraged efficiently. When congestion does occur on a medium to long term basis, **[TRADE SECRET DATA BEGINS**

TRADE SECRET DATA ENDS].

b. The rail delivery issues from 2014, **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]** IPL expects to retain rail cycle times that will provide security and reliability of coal supply over the medium term.

c. **[TRADE SECRET DATA BEGINS** **TRADE SECRET DATA ENDS]**.

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Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Division of Energy Resources
Information Request No. 28

Docket No.:	E999/AA-14-579
Date of Request:	March 18, 2015
Response Due:	March 30, 2015
Information Requested By:	Craig Addonizio
Date Responded:	March 30, 2015
Author:	Jim Dalton
Author's Title:	Mgr. Fuel Supply & Transport
Author's Telephone No.:	(608) 458-3375
Subject:	
Reference:	Coal Consumption and Inventories

Information Request No. 28

a. Please provide actual coal consumption by month at each of the utility's plants.

b. Please provide actual coal inventories by month at each of the utility's plants.

c. Please provide the desired coal inventory level for each of the utility's plants.

d. Please explain the reasoning behind the desired level of coal inventory for each of the utility's plants. Please explain any plant-specific considerations that influence the desired inventory.

Response:

a. Please see Confidential Attachment A, which shows actual coal consumption by month at each of IPL's plants for calendar years 2012 through 2014.

b. Please see Confidential Attachment A, which shows actual coal inventory levels by month at each of IPL's plants for calendar years 2012 through 2014.

c. As a guideline, IPL generally tries to have the coal piles at its rail-delivered plants average between **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** days of burn. For barge-delivered plants, the general guideline is to have between **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** days of burn at the end of the calendar year. A table in Attachment A shows approximate 'desired' inventory range levels in tons for each plant.

d. The guideline inventory levels are stated as ranges to account for the various factors. Among the factors considered are:
   1. Associated contractual minimum volume obligations under coal, rail, transload and barge agreements;
   2. Whether a plant takes deliveries via rail or barge – inventories at barge-delivered plants need to be sufficient at the end of the barge season in fall to last through the winter until the river re-opens in spring;
   3. Rail disruptions and flood and drought impacts on river traffic
   4. The length of time it takes for trains to travel between the mines and the plants (cycle times);
   5. The railcar capacity available to supply coal to each plant; railcar capacity is often shared between plants and thus the inventory levels need to vary over time as trainsets are available for shipments to each plant;
   6. Planned and unplanned maintenance outages at the plants, whether the generating unit(s) are unavailable due to maintenance work or the coal unloading equipment or rail tracks are unavailable due to maintenance work; inventories are often intentionally increased during maintenance outages because railcar capacity is not designed, nor needed, to simultaneously satisfy all plants' needs at peak generation times, generally summer months;
   7. The capacity of each plant's inventory footprint; and
   8. The variation in the quantities burned at each plant that can occur over time, in particular from year to year.

Below are explanations for unusual plant inventory levels during the years under review.

1. **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** year-end **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** inventory level was intentionally low because **[TRADE SECRET DATA BEGINS** [redacted]. **TRADE SECRET DATA ENDS]**
2. **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** inventory levels for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** were intentionally high because **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**

IPL Monthly Coal Consumption & Inventory Balances By Plant - 2012-2014

All values represent tons

2012	January		February		March		April		May		June		July		August		September		October		November		December	
Plant	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory	Consumption	Inventory
Burlington	[TRADE SECRET DATA BEGINS																							
Kapp																								
Lansing:																								
Ottumwa																								
Prairie Creek																								
Sutherland:																								
Louisa																								
Neal 3																								
Neal 4																								
2013																								
Plant																								
Burlington																								
Kapp																								
Lansing:																								
Ottumwa[1]																								
Prairie Creek																								
Sutherland																								
Louisa																								
Neal 3																								
Neal 4																								
2014																								
Plant																								
Burlington																								
Kapp																								
Lansing:																								
Ottumwa[1]																								
Prairie Creek																								
Sutherland																								
Louisa																								
Neal 3																								
Neal 4																								

[1] Values are for total plant

TRADE SECRET DATA ENDS]

Approximate 'Desired' Inventory Range Levels by plant

All values represent tons

		Delivery	Estimated 'Desired' Range		
Plant	Estimated Daily Burn[4]	R-rail; B-Barge	Low-end	High-end	
Burlington	[TRADE SECRET DATA BEGINS				on average
Kapp					at Year-end
Lansing					at Year-end
Ottumwa[1]					on average
Prairie Creek				TRADE SECRET DATA ENDS]	on average
Sutherland[2]	n/a	R	n/a	n/a	
Louisa[3]	n/a	R	n/a	n/a	
Neal 3[3]	n/a	R	n/a	n/a	
Neal 4[3]	n/a	R	n/a	n/a	

[1] Values are for total plant

[2] Not applicable, hasn't burned coal since early 2012

[3] Not applicable, Mid-Am operates this unit

[4] Based upon data used for 2014

Attachment E8

Xcel Electric's response to DOC discovery related to rail delivery issues

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Xcel Energy
Docket No.: E999/AA-14-579
Response To: Department of Commerce Information Request No. 21
Requestor: Craig Addonizio
Date of Request: March 18, 2015

Question:
Reference: Coal Procurement Strategy

a. How does the utility forecast its coal needs?

b. Please explain the utility's strategy for purchasing coal to meet its anticipated needs with respect to the timing of coal purchases for its coal-fired plants. In other words, on January 1, 2014, what percentage of anticipated coal needs for 2014 did the utility have secured? As of January 1, 2014, what percentage of anticipated coal needs for *2015* did the utility have secured? Etc. To the extent there are plant-specific considerations, please explain them.

c. If a particular coal-fired plant were dispatched less than expected during a given year (and thus burned less coal than expected), would the utility attempt to adjust coal deliveries in real-time, or simply allow coal inventory to build up at the plant and adjust deliveries at a later date?

Response:
a. Xcel Energy forecasts its fuel needs, including coal, through use of a production cost model which simulates operation of the NSP electric power system. The model forecasts generation from NSP resources, including coal generation, required to meet an hourly system load obligation over the next several years.

   The model determines the most economic manner in which to meet the hourly load obligation, taking into account forecast assumptions for: customer demand and energy requirements; required operating reserves, unit cost and performance assumptions for our existing generation fleet(variable O&M cost, startup cost, fuel cost, heat rate, operating constraints, forced outage rate, maintenance schedule); renewable energy from owned resources and purchase power agreements (PPAs), MISO market price assumptions; long-term PPAs; new committed resources; and planned retirements or PPA terminations.

The model results provide a forecast of generation by resource, including the amount of fuel needed for each fossil resource to achieve the forecast level of generation. The forecast informs Fuel Supply Operations of the annual amount of coal projected to be needed which they factor into their procurement decisions.

b. An analysis of fuel supply requirements for future years is performed in the first quarter of each year. This analysis leads to a solicitation during the second quarter for bids to supply unfilled requirements of the current year. This bidding process leads to purchases to meet 85 to 100 percent of requirements for the following year (Year One), 67 percent of requirements for the year after (Year Two), and 33 percent of requirements for the year after that (Year Three) – a rolling three-year schedule. When the terms of the offers are attractive, Xcel Energy may fill some or all of its future requirements for as many as five years.

   In addition to the annual analysis described above, Xcel Energy continually reviews forecasted generation and anticipated fuel consumption to determine changes in fuel requirements caused by such variables as weather, transportation availability, revisions to outage schedules, capacity factors and availability of purchased electric power and/or natural gas at attractive prices. Imbalances between fuel supplies and requirements are then corrected through purchases and sales based on spot fuel market and transportation conditions at that time.

   On January 1, 2014, the following percentages of NSP's coal needs were under contract: 95 percent of 2014 requirements, 73 percent of 2015 requirements, 31 percent of 2016 requirements, and 0 percent of the requirements for 2017 and beyond.

c. There are several options available to adjust coal delivery volumes in the event that a coal-fired power plant was dispatched below forecasted levels. Generally, the NSP plants would strive to take the contracted volumes of coal up to maximum storage levels that are compliant with environmental permit limitations and plant safety protocols. Additionally, the coal contracts for the NSP plants provide for flexibility in the delivery destinations. This enables the movement of contracted coal from one plant to another. If, for instance, coal inventory levels at the Black Dog plant were approaching maximum levels, the contracted coal from the Wyoming mine could be arranged for delivery to the Sherburne County or A.S. King plants and vice versa. A third option would be to negotiate terms with the coal supplier(s) to move undelivered contracted tons into the next calendar year.

Preparer:	James Witt	David Horneck
Title:	Principal Fuel Portfolio Coordinator	Manager
Department:	Fuel Supply Operations	Generation Model Services
Telephone:	303-571-7158	303-571-2816
Date:	March 30, 2015	

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Xcel Energy			
Docket No.:	E999/AA-14-579		
Response To:	Department of Commerce	Information Request No.	22
Requestor:	Craig Addonizio		
Date of Request:	March 18, 2015		

Question:

Please provide a general discussion describing the utility's strategy for procuring rail transportation for coal, and how that strategy relates to the utility's strategy for procuring coal. Please address the following questions, but also provide any other relevant information.

a. Is it the utility's goal to transport all of its coal via multi-year rail transportation contracts? Or does the utility rely on rail contracts for only a portion of its coal transportation needs, and rely on shorter-term solutions for a portion (e.g. rail transportation at tariffed, common carrier rates).

b. Are coal deliveries by rail to each coal-fired plant governed by separate rail contracts? Or can one contract cover deliveries to multiple plants?

c. For each plant, does the utility typically have one rail transportation contract in place at a time? Or are plants served under multiple rail transportation contracts with differing terms (e.g. volumes and expiration dates)?

d. How does the utility's procurement of rail transportation accommodate changes to its forecasted coal needs?

Response:

Based on the projected long-term coal requirements of the plants, the Company negotiates multi-year coal transportation agreements with the railroads at volumes commensurate with the fuel requirements for the facility. The terms of the existing long-term agreements generally provide for minimum and maximum annual volumes to be delivered. The agreements each contain a liquidated damage clause addressing shortfalls in shipments by either party.

a. NSP relies on multi-year agreements for all of its coal transportation needs.

b. The Sherburne County plant is served by the Burlington Northern Santa Fe (BNSF) Railroad which serves only this facility.

   The Black Dog and A.S. King plants are served by the Union Pacific (UP) railroad. The UP transportation agreement provides for transportation of coal to both plants.

c. There is one, multi-year, transportation agreement for the Sherburne County plant, which is served by the BNSF railroad. There is one multi-year agreement that provides service to both the Black Dog and A.S. King plants, which are served by the UP railroad. The common terms address the joint volume requirements of the two plants with rail rates specified for each destination.

d. Generally, there is sufficient flexibility incorporated into the transportation agreements to accommodate the variability of the plants' coal requirements due to changes in maintenance outages, unit demand, and other factors not contemplated when the original annual volume forecasts were provided to the rail carriers in October each year. While those changes do occur, they are usually not materially significant and can be managed through the terms outlined in the transportation agreements.

Preparer:	James Witt
Title:	Principal Fuel Portfolio Coordinator
Department:	Fuel Supply Operations
Telephone:	303-571-7158
Date:	March 30, 2015

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TRADE SECRET DATA EXCISED

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Xcel Energy			
Docket No.:	E999/AA-14-579		
Response To:	Department of Commerce	Information Request No.	23
Requestor:	Craig Addonizio		
Date of Request:	March 18, 2015		

Question:

a. Please provide copies of all rail transportation contracts the utility has been party to at any time since January 1, 2011 (including contracts that were signed prior to January 1, 2011, but still in effect on that date).

b. Please describe, in non-technical terms, the terms of the contracts provided in response to part (a), including pricing, annual volumes, the responsibilities of the rail carriers, the responsibilities of the utility, etc.

c. Please explain whether the contracts provided in response to part (a) govern *all* coal deliveries by rail to the utility's plants, or if any coal gets delivered by rail pursuant to any other transactions or agreements?

Response:

a. Please see the following attachments, all of which are marked Trade Secret, for copies of the rail transportation contracts to which NSPM was a party since January 1, 2011:
   - Attachment A: BNSF
   - Attachment B: Union Pacific (contract expired in 2013)
   - Attachment C: Union Pacific (contract began in 2014)

b. The term of the BNSF contract is from January 1, 2011 through **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. Further details are described in Attachment A.

The term of the expired contract with Union Pacific was from August 1, 2001 through December 31, 2013. It provided for the shipment of coal **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. Further details are described in Attachment B.

The term of the current Union Pacific contract is from January 1, 2014 through **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. Further details are described in Attachment C.

c. The contracts described above govern(ed) all coal rail deliveries to the NSP plants.

Preparer:	James Witt
Title:	Principal Fuel Portfolio Coordinator
Department:	Fuel Supply Operations
Telephone:	303-571-7158
Date:	March 30, 2015

Attachment A

This attachment is Trade Secret in its entirety.

Attachment B

This attachment is Trade Secret in its entirety.

Attachment C

This attachment is Trade Secret in its entirety.

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Xcel Energy			
Docket No.:	E999/AA-14-579		
Response To:	Department of Commerce	Information Request No.	24
Requestor:	Craig Addonizio		
Date Received:	March 18, 2015		

Question:
Reference: Rail Deliveries

a. For each of the contracts provided in response to the prior Information Request, please provide the utility's desired level of deliveries each year. If a contract required (or requires) the utility to nominate a specific level of deliveries for a calendar year prior to the start of that calendar year, please provide the nominated amount of deliveries, and explain how the nominated amount was derived.

b. Please provide actual deliveries pursuant to each contract by month since January 2011.

c. Please provide actual coal deliveries to each of the utility's coal plants by month since 2011.

d. If the delivery data provided in response to part (c) does not reconcile with the delivery data provided in response to part (b), please explain why.

Response:
a. Please see Attachment A for each plant's desired level of deliveries for each year since 2011.

   The annual railroad nominations are based on the most current burn forecast for each plant, with consideration of contractual commitments with the railroads and the coal suppliers. In addition to the expected burn volumes, the current inventory levels at each plant are considered. The delivery forecast may then be increased or decreased appropriately to manage the inventory to optimal levels. Finally, the required annual volumes are levelized on a monthly basis to the extent practicable, to abide by the contractual requirements to maintain deliveries on a rateable basis throughout the year.

b. Please see Attachment B for the actual deliveries pursuant to each contract by month since January 2011.

c. Please see Attachment B for the actual coal deliveries to each of coal plant by month since 2011.

d. The monthly actual deliveries by contract reconcile with the monthly actual deliveries by plant.

Preparer:	James Witt
Title:	Principal Fuel Portfolio Coordinator
Department:	Fuel Supply Operations
Telephone:	303-571-7158
Date:	March 30, 2015

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Northern States Power Company Minnesota
Coal Tons Nominated

[TRADE SECRET BEGINS

BY PLANT	2011	2012	2013	2014	2015
A.S.King					
UP tons					
Black Dog					
UP tons					
Sherco****					
BNSF tons					

BY CONTRACT	2011	2012	2013	2014	2015
UP (expired)					
UP (current)					
BNSF					

TRADE SECRET ENDS]

* The Sherco nomination was made before the Unit 3 turbine generator event occurred on November 19, 2011.
** A range was nominated depending on Sherco Unit 3 return date (minimum of range shown).
*** Black Dog Units 3 and 4 will retire April 15, 2015.
**** Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

Northern States Power Company Minnesota
Coal Tons Delivered - 2011

BY PLANT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
A.S.King													
UP tons	176,033	194,966	139,867	73,273	206,710	182,341	157,724	157,936	193,949	171,326	169,168	169,168	1,992,461
Black Dog													
UP tons	34,992	34,295	71,828	0	36,777	97,711	86,496	73,088	72,913	49,645	85,182	85,182	728,109
Sherco*													
BNSF tons	595,672	532,659	718,857	694,560	348,659	461,891	654,375	511,974	577,542	663,936	690,057	690,057	7,140,239

BY CONTRACT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
UP (expired) - Black Dog and King	211,025	229,261	211,695	73,273	243,487	280,052	244,220	231,024	266,862	220,971	254,350	254,350	2,720,570
BNSF - Sherco*	595,672	532,659	718,857	694,560	348,659	461,891	654,375	511,974	577,542	663,936	690,057	690,057	7,140,239

* Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

Northern States Power Company Minnesota
Coal Tons Delivered - 2012

BY PLANT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
A.S.King													
UP tons	190,062	155,502	144,643	145,803	24,268	96,284	181,149	180,779	133,320	192,444	181,272	181,272	1,806,798
Black Dog													
UP tons	84,540	36,185	61,072	49,023	72,473	48,892	73,079	72,838	84,726	73,053	36,573	36,573	729,027
Sherco*													
BNSF tons	440,596	263,655	207,611	251,590	363,138	349,250	389,519	418,071	458,430	432,366	556,341	556,341	4,686,908

BY CONTRACT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
UP (expired) - Black Dog and King	274,602	191,687	205,715	194,826	96,741	145,176	254,228	253,617	218,046	265,497	217,845	217,845	2,535,825
BNSF - Sherco*	440,596	263,655	207,611	251,590	363,138	349,250	389,519	418,071	458,430	432,366	556,341	556,341	4,686,908

* Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

Northern States Power Company Minnesota
Coal Tons Delivered - 2013

BY PLANT		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
A.S.King	UP tons	172,192	114,773	0	0	35,866	132,343	145,328	158,184	133,373	143,968	180,578	180,578	1,397,183
Black Dog	UP tons	57,343	58,012	69,400	45,646	12,416	60,107	47,804	60,202	84,148	48,500	48,650	48,650	640,878
Sherco*	BNSF tons	498,551	496,899	487,429	534,762	501,727	321,037	322,326	306,292	396,979	356,167	450,447	450,447	5,123,063

BY CONTRACT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
UP (expired) - Black Dog and King	229,535	172,785	69,400	45,646	48,282	192,450	193,132	218,386	217,521	192,468	229,228	229,228	2,038,061
BNSF - Sherco*	498,551	496,899	487,429	534,762	501,727	321,037	322,326	306,292	396,979	356,167	450,447	450,447	5,123,063

* Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

Northern States Power Company Minnesota
Coal Tons Delivered - 2014

BY PLANT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
A.S.King													
UP tons	77,402	166,236	139,997	60,440	107,197	132,767	183,817	172,197	195,165	208,325	196,107	196,107	1,835,757
Black Dog													
UP tons	89,412	63,435	75,344	77,374	90,584	64,615	64,369	65,007	78,690	90,911	89,499	89,499	938,739
Sherco*													
BNSF tons	418,037	425,293	415,593	513,644	652,765	496,744	540,926	500,817	553,114	537,029	585,776	585,776	6,225,514

BY CONTRACT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
UP (current) - Black Dog and King	166,814	229,671	215,341	137,814	197,781	197,382	248,186	237,204	273,855	299,236	285,606	285,606	2,774,496
BNSF - Sherco*	418,037	425,293	415,593	513,644	652,765	496,744	540,926	500,817	553,114	537,029	585,776	585,776	6,225,514

* Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

Northern States Power Company Minnesota
Coal Tons Delivered - 2015

BY PLANT		JAN	FEB	TOTAL YTD
A.S.King				
	UP tons	38,263	38,592	76,855
Black Dog				
	UP tons	163,616	144,720	308,336
Sherco*				
	BNSF tons	923,592	684,051	1,607,643

BY CONTRACT	JAN	FEB	TOTAL YTD
UP (current) - Black Dog and King	201,879	183,312	385,191
BNSF - Sherco*	923,592	684,051	1,607,643

* Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

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Xcel Energy		
Docket No.:	E999/AA-14-579	
Response To:	Department of Commerce	Information Request No. 25
Requestor:	Craig Addonizio	
Date Received:	March 18, 2015	

Question:
Reference: Railroad Performance

a. Please explain whether, under the terms of each of the utility's rail transportation contracts, the railroad has met its delivery obligations.

b. Please explain whether any railroads have faced any penalties, financial or otherwise, pursuant to a contract with the utility. If any railroads have paid a financial penalty, please explain whether this penalty was credited to ratepayers via the fuel clause adjustment.

c. If the railroads have met their delivery obligations as specified in the contracts, please explain why coal inventories were or are low.

Response:
a. Both the BNSF and the UP met their performance obligations under their respective Rail Transportation agreements for 2014. Please note that **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

b. **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

c. It is common for coal inventory levels at plants to fluctuate as a result of various circumstances such as equipment outages, generation levels, railroad performance, and number of railcar sets in service. Extreme events such as severe weather, prolonged railcar dumper outages, and railroad track damage can result in significant short-term changes in coal inventory levels. The delivery obligations under the BNSF and UP Rail Transportation agreements are annual obligations and**[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

Preparer:	H. Craig Romer
Title:	Director
Department:	Fuel Supply Operations
Telephone:	303-571-2835
Date:	March 30, 2015

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Xcel Energy			
Docket No.:	E999/AA-14-579		
Response To:	Department of Commerce	Information Request No.	26
Requestor:	Craig Addonizio		
Date Received:	March 18, 2015		

Question:
Reference: Impacts of Delivery Delays

a. Please provide a detailed discussion of any coal transportation delays the utility has experienced since January 1, 2013, and the impacts those delays have had on the utility's coal inventories.

b. Please describe any actions the utility has undertaken to conserve coal in response to any coal transportation delays it has experienced.

c. If the utility limited production at any of its coal plants in order to conserve coal, please specifically explain how the Company achieved this reduction (e.g. a change in the plant's offer price in the MISO market, an artificial limit on available capacity, etc.).

d. If the utility limited production at any of its coal plants in order to conserve coal, please explain why the utility thought this action was necessary, and provide copies of any and all analyses the utility relied upon in deciding to limit energy production (e.g. quantitative or qualitative cost-benefit analyses, etc.). If the utility was concerned that a plant's coal inventory would fall below a predetermined minimum, please explain how the minimum inventory was determined.

e. Please state whether the coal conservation efforts described in response to parts (b) and (c) have ended or are ongoing.

f. To the extent that the utility reduced production at its coal plants, please estimate the incremental costs associated with the replacement energy purchased from the MISO market or produced at one of the utility's other generating plants.

g. To the extent that the utility reduced production at its coal plants, please explain any steps the utility took to protect ratepayers from higher costs associated with the replacement energy. If the utility took no steps, please explain why.

Response:

a. The BNSF railroad began to have performance issues delivering coal from Wyoming and Montana mines to the Sherco plant around October 2013. The railroad initially attributed its service problems to increased crude tank trains originating in the Bakken oil fields and a robust grain harvest. The BNSF later attributed the problems to track maintenance programs, crew shortages, higher traffic volumes and extreme weather events, including the severe winter of 2013-2014. Coal inventory levels dropped to relatively low levels in the early part of 2014 but returned to normal optimal levels by February 2015. The BNSF improved overall line capacity on its northern routes, improved track conditions with maintenance activities, added locomotives and added significant personnel to key segments of the northern route to improve traffic flows.

   In contrast, the plants served by the Union Pacific Railroad (UP) experienced a downward trend in railroad deliveries in the first quarter of 2014 due to the extreme weather events during the severe winter of 2013-2014. The UP focused its attention on restoring inventories to reasonable levels adding additional railroad equipment and personnel and changed the operating process to better accommodate the increased traffic levels in the Twin Cities area in second and third quarters 2014. The inventories returned to normal levels in early second quarter 2014 and have remained at normal optimal levels since then. No coal conservation was needed at our UP served coal-fired stations.

b. Xcel Energy utilized a cost adder in our energy offers submitted to MISO to help restore coal inventory levels by reducing generation production at the Sherco units during periods with lower Locational Marginal Prices (LMP). This approach was considered more efficient than an artificial limit on the units, as it allowed for the Sherco units to be backed down during periods of lower replacement energy prices.

c. Please see the response to Part b. above.

d. The optimal coal inventory levels for the Sherco station were determined by an outside consultant. The inputs to this study included, but were not limited to, generation capabilities, the number of units at the facility, maximum daily coal consumption, rail equipment in service, distance from source mines, and replacement power prices. This study determined that the optimal inventory level

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TRADE SECRET ENDS]. Implicit in this study is the recognition that there are trade offs between the cost of working capital associated with maintaining inventory and the costs of shortages requiring replacement power purchases.

With that said, there was no way to perform a meaningful qualitative or quantitative economic analysis for a short term disruption in rail service. The only data available to us was actual delivery performance during the period and the BNSF forecast for future deliveries, which were consistently overly optimistic. We did, however, ask MISO to perform a power flow study to determine the potential impact on reliability should Sherco run out of coal. MISO's response to our request is included as Attachment A. The decision to begin coal conservation when inventories had dropped to **[TRADE SECRET BEGINS**
TRADE SECRET ENDS] was driven by the lack of certainty of future coal deliveries, and the need for Sherco to be available for full load during the summer months.

e. The coal conservation approach described in Part b. above is not ongoing. The approach was used during the period March 14, 2014 through the deadline for the August 6, 2014 market.

f. NSP estimated that the total cost of the approach described in Part b. above is $12.9 million. Please note this amount is slightly higher than the $12.4 million previously reported because of a typographical error.

g. We took a number of steps to ensure cost to ratepayers was minimized. The coal conservation effort itself was an attempt to reduce the risk that customers would pay replacement energy costs in the summer, when prices are typically higher. Second, NSP engaged in high level face-to-face meetings between NSP and BNSF senior management, and weekly executive conference calls to discuss issues. Third, NSP provided testimony to the Surface Transportation Board that highlighted the importance of Sherco to regional electric reliability. This was additionally supported through contact with our state and federal lawmakers who separately encouraged STB attention to the matter. Fourth, NSP met with the Surface Transportation Board customer representative to get help pressing the BNSF to improved deliveries to Sherco. Finally, NSP maximized the availability of its other generating facilities, both owned and contracted.

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Preparer:	H. Craig Romer	Jeff Butler
Title:	Director	Regulatory Consultant
Department:	Fuel Supply Operations	Power Operations
Telephone:	303-571-2835	303-571-6774
Date:	April 2, 2015	

MISO

March 18, 2014

Steve Beuning
Xcel Energy
1800 Larimer St, Suite 1000
Denver, CO 80202

Steve,

In response to your inquiry regarding potential fuel issues at the Sherburne County plant, our System Operations group has conducted an assessment of the potential operational impacts of being without all three units for an extended period of time, focusing on the months of April and May.

As you know, the spring season is a very common time for Generation Operators and Transmission Operators to perform maintenance on their facilities and this year is no different. A number of major generation and transmission facilities are already scheduled for maintenance outages that will impact the Twin Cities load center and much of western Wisconsin, Minnesota, and Northern Iowa. The generation outages will require additional imports to the region. At the same time, the transmission outages will limit the amount of energy that can be imported to these areas from the balance of MISO or its neighbors.

To comply with NERC standards, and ensure the reliability of the electrical system, MISO along with its member and neighboring Transmission Owners, plan and operate the system to be secure for the loss of the largest single contingency. For this region, and certain combinations of the scheduled outages, Unit #3 at Sherburne County (~960 MW) was expected be the largest contingency. Loss of the remaining two units and their combined capacity in excess of 1350 MW would pose a major operational concern during these outages, especially if the outage was prolonged. Any additional forced outages resulting from equipment failures or severe weather would put at risk a significant amount of load.

Moving past the spring maintenance season and into summer, the numbers of scheduled outages are reduced as we move into the peak load season. The predominant operational concern becomes increased system loads and ensuring sufficient resources are available to serve the load. This tends to be more of a concern for the MISO footprint as a whole. The Sherburne County plant is among the largest in the MISO fleet, and is therefore a key component of our overall resource mix. At a minimum, unavailability of these resources would result in higher prices for replacement energy. Should MISO experience a peak load event while these units are unavailable, MISO may be forced into an Emergency Energy situation, which could include involuntary reductions of customer loads.

Respectfully,

Clair J. Moeller
Executive Vice President, Transmission & Technology

Midcontinent Independent System Operator, Inc.
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Xcel Energy		
Docket No.:	E999/AA-14-579	
Response To:	Department of Commerce	Information Request No. 27
Requestor:	Craig Addonizio	
Date Received:	March 18, 2015	

Question:

Reference: Rail Delivery Improvements

a. If the utility is working directly with railroads to improve delivery times in the short and medium terms, please explain the nature of these efforts. Please specifically explain what options are available to the railroad to improve delivery times in the short and medium term.

b. Please provide the utility's perspective on when and how its rail delivery issues will be fully resolved, and its expectations for rail service for the next few years.

c. Please explain whether the utility plans to alter its coal transportation and procurement strategies in the future in response to any delays it has experienced (i.e. higher inventories, higher transportation volumes, different performance requirements for railroads, larger penalties for railroads, etc.).

Response:

a. Over the past year, we have been actively managing the coal delivery situation in many ways, but in particular, by staying in close communication with BNSF and UP officials at many management levels, including daily staff calls, weekly executive conference calls and monthly in-person meetings with top management. We believe the early phases of these actions resulted in improved service and additional equipment to try and meet our required deliveries. Our primary interaction has been with the BNSF, as inventories returned to normal or optimal levels at UP-served facilities more quickly. Since inventory levels have improved in recent months, we are reducing the frequency of these calls and meetings with BNSF. We cannot speculate on what options are available to the railroads to improve delivery times.

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

b. Coal inventory levels at both the Sherco and A. S. King plants are currently at or above optimal levels, we believe that the rail delivery issues are essentially resolved. We will continue to closely monitor coal inventory levels going forward.

c. The rail contracts for Sherco and A. S. King plants do not expire until **[TRADE SECRET BEGINS** **TRADE SECRET ENDS]** respectively. When we begin negotiations of new rail transportation agreements, we will look for additional improvements to the terms and conditions of the agreements that will better suit our requirements and address our needs at the time.

Preparer:	H. Craig Romer
Title:	Director
Department:	Fuel Supply Operations
Telephone:	303-571-2835
Date:	March 30, 2015

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

☐ **Non Public Document – Contains Trade Secret Data**
☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy		
Docket No.:	E999/AA-14-579	
Response To:	Department of Commerce	Information Request No. 28
Requestor:	Craig Addonizio	
Date Received:	March 18, 2015	

Question:

Reference: Coal Consumption and Inventories

a. Please provide actual coal consumption by month at each of the utility's plants.

b. Please provide actual coal inventories by month at each of the utility's plants.

c. Please provide the desired coal inventory level for each of the utility's plants.

d. Please explain the reasoning behind the desired level of coal inventory for each of the utility's plants. Please explain any plant-specific considerations that influence the desired inventory.

Response:

a-c. The actual coal consumption, actual coal inventory, and target coal inventory levels at each of the plants by month for 2013 and 2014 are shown in Attachment A.

d. The desired coal inventory level for each of the plants is based on many factors but at its basic level is the amount of coal that is needed to be onsite in order to provide sufficient inventory that a facility can be available for operations in the event of a railroad or delivery disruption. That level is determined by analyzing the type and distance of the mine to the facility, the number of railcar sets in service, the historic cycle times, the number of units at a facility, and the carrying cost of inventory and then compares those factors to the replacement power costs in a given market should a unit run short of fuel. The analysis provides an optimal inventory level that should be maintained given the historical data with a margin for changed circumstances that may be unforeseen. A small plant with the ability to fuel switch to natural gas will carry less inventory than a large facility with a single fuel source at great distance.

Preparer:	H. Craig Romer
Title:	Director
Department:	Fuel Supply Operations
Telephone:	303-571-2835
Date:	March 30, 2015

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

Northern States Power Company

Actual Coal Consumption and Coal Inventory

[TRADE SECRET BEGINS

Station		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December
Sherco (MT)*	Burn (tons)												
Sherco (WY)*	Burn (tons)												
Black Dog**	Burn (tons)												
Allen S King	Burn (tons)												

NSP Inventory Station		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December
Sherco MT*	Inventory (% of goal)												
	Inventory (days goal)												
Sherco WY*	Inventory (% of goal)												
	Inventory (days goal)												
King	Inventory (% of goal)												
	Inventory (days goal)												
Black Dog**	Inventory (% of goal)												
	Inventory (days goal)												

TRADE SECRET ENDS]

*Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

**Beginning in 2015, Black Dog has been burning down inventory in anticipation of a 4/15/15 retirement.

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

Northern States Power Company

Actual Coal Consumption and Coal Inventory

[TRADE SECRET BEGINS

Station		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December
Sherco (MT)*	Burn (tons)												
Sherco (WY)*	Burn (tons)												
Black Dog**	Burn (tons)												
Allen S King	Burn (tons)												

NSP Inventory Station		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December
Sherco MT*	Inventory (% of goal)												
	Inventory (days goal)												
Sherco WY*	Inventory (% of goal)												
	Inventory (days goal)												
King	Inventory (% of goal)												
	Inventory (days goal)												
Black Dog**	Inventory (% of goal)												
	Inventory (days goal)												

TRADE SECRET ENDS]

*Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

**Beginning in 2015, Black Dog has been burning down inventory in anticipation of a 4/15/15 retirement.

PUBLIC DOCUMENT:
TRADE SECRET DATA EXCISED

Northern States Power Company

Actual Coal Consumption and Coal Inventory

[TRADE SECRET BEGINS

Station		2015 January	2015 February
Sherco (MT)*	Burn (tons)		
Sherco (WY)*	Burn (tons)		
Black Dog**	Burn (tons)		
Allen S King	Burn (tons)		

NSP Inventory Station		2015 January	2015 February
Sherco MT*	Inventory (% of goal)		
	Inventory (days goal)		
Sherco WY*	Inventory (% of goal)		
	Inventory (days goal)		
King	Inventory (% of goal)		
	Inventory (days goal)		
Black Dog**	Inventory (% of goal)		
	Inventory (days goal)		

TRADE SECRET ENDS]

*Sherco data only accounts for NSP's share of Sherco 3 unit ownership, not the portion owned by SMMPA.

**Beginning in 2015, Black Dog has been burning down inventory in anticipation of a 4/15/15 retirement.

Attachment E9

Dakota Electric Association: FYE14 Energy Cost Over/Under-Recovery

DEA	kWh Sales (a)	MN Energy Costs (b)	MN Recovery (c)	MN Energy Costs ($/kWh) (d)	MN Recovery ($/kWh) (e)
Jul-13	179,824,682	$ 18,093,874	$ 15,200,419	0.101	0.085
Aug-13	188,310,327	$ 17,954,111	$ 15,944,284	0.095	0.085
Sep-13	187,561,295	$ 11,308,960	$ 14,116,705	0.060	0.075
Oct-13	145,878,388	$ 8,816,516	$ 10,971,025	0.060	0.075
Nov-13	134,685,629	$ 9,166,954	$ 10,090,250	0.068	0.075
Dec-13	147,915,540	$ 12,763,808	$ 11,101,143	0.086	0.075
Jan-14	166,433,059	$ 13,354,589	$ 12,798,553	0.080	0.077
Feb-14	161,133,434	$ 11,318,423	$ 12,405,278	0.070	0.077
Mar-14	150,245,130	$ 11,626,838	$ 11,433,209	0.077	0.076
Apr-14	132,451,285	$ 9,433,000	$ 9,983,010	0.071	0.075
May-14	137,555,137	$ 10,970,295	$ 10,341,065	0.080	0.075
Jun-14	148,253,680	$ 14,775,237	$ 12,703,575	0.100	0.086
FYE14	1,880,247,586	149,582,605	147,088,516	0.080	0.078

Source (a): Dakota's AAA filing, Exhibit CII, page 1 and RTA 2015 Filing, Schedule F-2 (Docket No. E111/M-15-40)

Source (b): Dakota's AAA filing, Exhibit CII, page 1.

Source (c): Dakota's AAA filing, Exhibit CII, page 1.

(d) = (b)/(a)

(e) = (c)/(a)

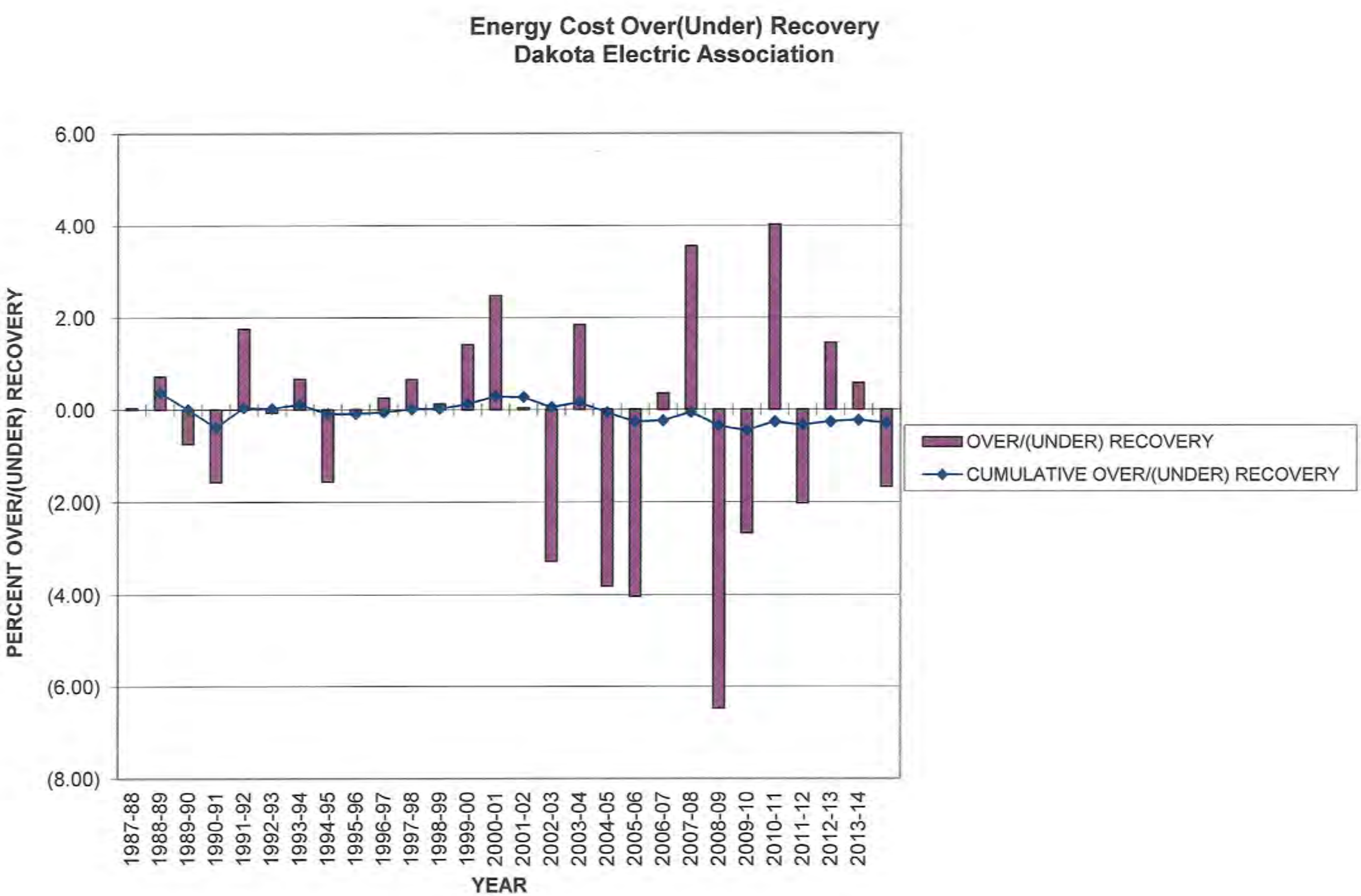
DAKOTA ELECTRIC ASSOCIATION
Summary of Fuel-Cost Recovery Since 1986-1987

Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	0.03		
1987-88	0.72	0.38	
1988-89	(0.74)	0.00	
1989-90	(1.57)	(0.39)	
1990-91	1.76	0.04	
1991-92	(0.07)	0.02	
1992-93	0.67	0.11	
1993-94	(1.56)	(0.10)	
1994-95	(0.08)	(0.09)	
1995-96	0.25	(0.06)	
1996-97	0.66	0.01	
1997-98	0.12	0.02	
1998-99	1.41	0.12	
1999-00	2.47	0.29	
2000-01	0.04	0.27	
2001-02	(3.27)	0.05	
2002-03	1.85	0.16	0.19
2003-04	(3.81)	(0.06)	(0.04)
2004-05	(4.04)	(0.27)	(0.43)
2005-06	0.35	(0.24)	(0.42)
2006-07	3.56	(0.06)	(0.13)
2007-08	(6.47)	(0.35)	(0.79)
2008-09	(2.66)	(0.45)	(1.20)
2009-10	4.02	(0.26)	(1.04)
2010-11	(2.02)	(0.34)	(1.25)
2011-12	1.46	(0.27)	(0.78)
2012-13	0.58	(0.23)	(0.65)
2013-14	(1.67)	(0.30)	(0.74)

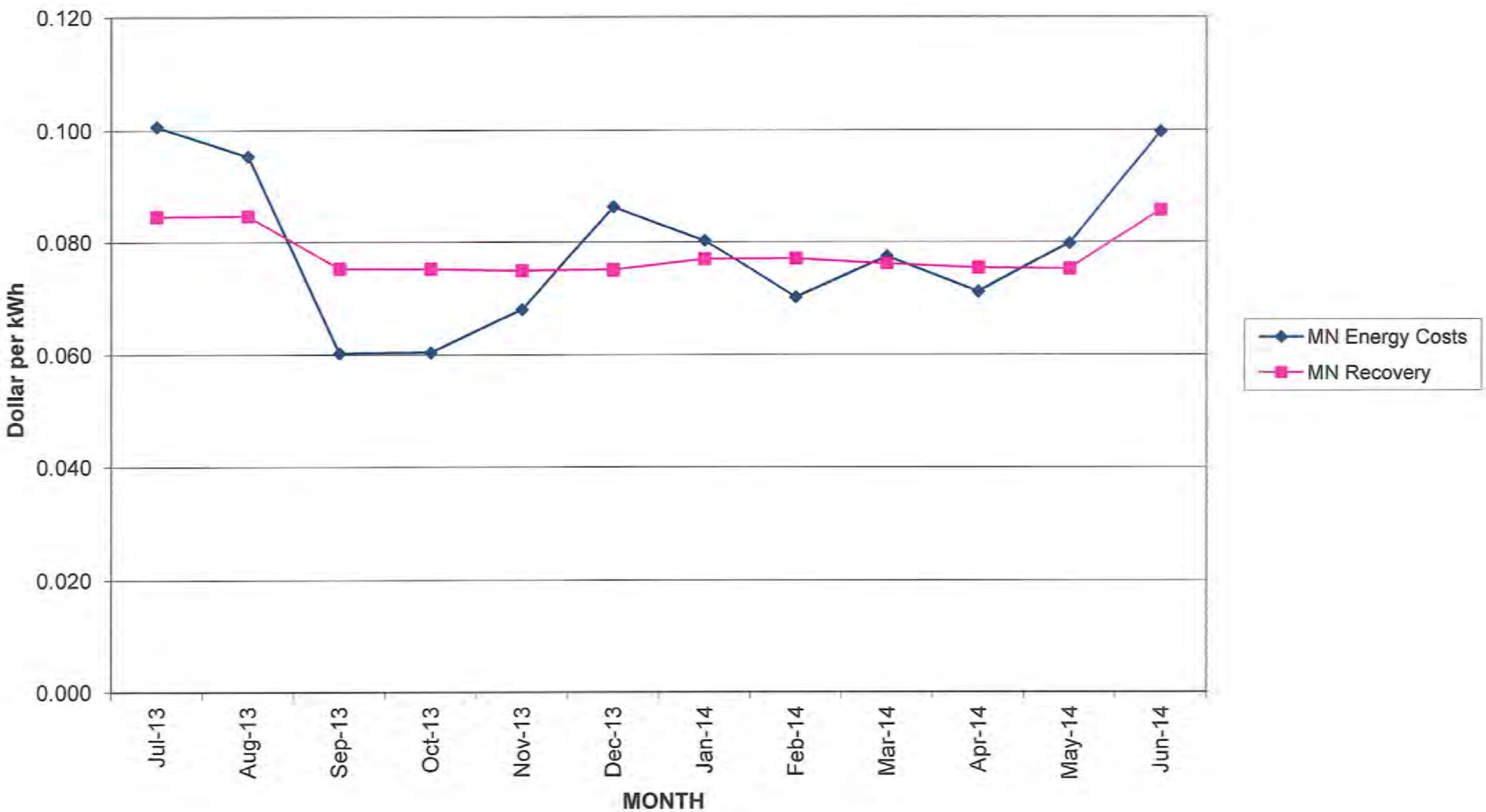
Source: Previous AAA filings up to FYE14 and table below for FYE14 data.

Month		Total Company Recovery, July 2013 - June 2014, By Month Minnesota Energy Costs	Minnesota Recovery	Over(Under) Recovery	Over(Under) Percentage
		(a)	(b)	(c)	(d)
July	$	18,093,874	$15,200,419	($2,893,455)	(15.99%)
August	$	17,954,111	$15,944,284	($2,009,827)	(11.19%)
September	$	11,308,960	$14,116,705	$2,807,745	24.83%
October	$	8,816,516	$10,971,025	$2,154,509	24.44%
November	$	9,166,954	$10,090,250	$923,296	10.07%
December	$	12,763,808	$11,101,143	* ($1,662,665)	(13.03%)
January	$	13,354,589	$12,798,553	($556,036)	(4.16%)
February	$	11,318,423	$12,405,278	$1,086,855	9.60%
March	$	11,626,838	$11,433,209	($193,629)	(1.67%)
April	$	9,433,000	$9,983,010	$550,010	5.83%
May	$	10,970,295	$10,341,065	($629,230)	(5.74%)
June	$	14,775,237	$12,703,575	($2,071,662)	(14.02%)
Total	**$**	**149,582,605**	**$147,088,516**	**($2,494,089)**	**(1.67%)**

Source: Attachment
(c) = (b) - (a)
(d)= (c)/(a)


Energy Cost Over(Under) Recovery
Dakota Electric Association
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
PERCENT OVER/(UNDER) RECOVERY
1987-88
1988-89
1989-90
1990-91
1991-92
1992-93
1993-94
1994-95
1995-96
1996-97
1997-98
1998-99
1999-00
2000-01
2001-02
2002-03
2003-04
2004-05
2005-06
2006-07
2007-08
2008-09
2009-10
2010-11
2011-12
2012-13
2013-14
YEAR
OVER/(UNDER) RECOVERY
CUMULATIVE OVER/(UNDER) RECOVERY

Dakota Electric Association's Energy Costs and Recovery
July 2013-June 2014



Attachment E10

Interstate Electric: FYE14 Energy Cost Over/Under-Recovery

IPL	kWh Retail & Firm Resale (a)	kWh MN Retail Sales (b)	(RES-SN) kWh MN not subj FCA (c)		System Costs (d)
Jul-13	1,423,582,613	73,792,978	183,602	$	30,478,987
Aug-13	1,329,824,579	70,130,169	160,001	$	32,020,929
Sep-13	1,445,861,702	80,597,290	191,584	$	28,001,401
Oct-13	1,294,053,794	69,124,155	133,773	$	31,186,891
Nov-13	1,264,131,918	73,740,009	134,499	$	28,499,008
Dec-13	1,428,127,396	82,110,441	182,309	$	29,752,307
Jan-14	1,530,824,178	85,850,362	210,173	$	34,659,872
Feb-14	1,396,816,270	76,617,847	179,782	$	39,970,155
Mar-14	1,334,015,292	70,993,670	164,733	$	26,521,888
Apr-14	1,216,122,758	63,760,859	136,916	$	23,774,233
May-14	1,192,615,513	61,476,876	128,495	$	29,672,617
Jun-14	1,313,809,648	67,536,526	162,107	$	31,298,734
FYE14	16,169,785,661	875,731,182	1,967,974	$	365,837,022

MWh Sendout	17,033,764	927,154	(Source: Exhibit C, Sheet 3 of 4)
		5.4430%	

Source (a): IPL's monthly FCAs
Source (b): IPL's monthly FCAs
Source (c): IPL's monthly FCAs.
Source (d): IPL's monthly FCAs.

IPL's under/over recovery of costs
Revenues are collected through base rates and the FCA.
Base rates revenues are calculated as the product of the base cost ($/kWh) and the MN kWh retail sales.
FCA revenues are calculated as the product of the FCA factor and the MN kWh retail sales subject to FCA.
FCA factor is calculated based on the ratio of net system costs and net system kWh sales (system retail, resale and Second Nature)
MN energy costs are calculated as the product of the net system costs by the share of MN transmission/primary/secondary retail kWh sales
(formula uses MN retail allocation based on an annual system sendout: retail by state and total wholesale kWh)
Above data does not include asset or non asset based margins

Minnesota Base Cost ($/kWh): 0.02465

IPL	FCA ($/kWh) (e)	Calculated FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-13	(0.00488)	$ (361,147)	$ 1,818,997	$ 1,457,850	$ 1,658,982	$ (201,133)	0.020	0.022
Aug-13	(0.00386)	$ (271,570)	$ 1,728,709	$ 1,457,139	$ 1,742,911	$ (285,772)	0.021	0.025
Sep-13	(0.00318)	$ (257,969)	$ 1,986,723	$ 1,728,754	$ 1,524,126	$ 204,627	0.021	0.019
Oct-13	(0.00195)	$ (135,940)	$ 1,703,910	$ 1,567,971	$ 1,697,514	$ (129,543)	0.023	0.025
Nov-13	(0.00303)	$ (224,123)	$ 1,817,691	$ 1,593,568	$ 1,551,211	$ 42,357	0.022	0.021
Dec-13	(0.00305)	$ (251,618)	$ 2,024,022	$ 1,772,405	$ 1,619,429	$ 152,976	0.022	0.020
Jan-14	(0.00132)	$ (115,143)	$ 2,116,211	$ 2,001,068	$ 1,886,550	$ 114,518	0.023	0.022
Feb-14	(0.00301)	$ (232,232)	$ 1,888,630	$ 1,656,398	$ 2,175,590	$ (519,192)	0.022	0.028
Mar-14	(0.00288)	$ (205,822)	$ 1,749,994	$ 1,544,172	$ 1,443,596	$ 100,575	0.022	0.020
Apr-14	0.00084	$ 52,100	$ 1,571,705	$ 1,623,805	$ 1,294,040	$ 329,765	0.025	0.020
May-14	(0.00030)	$ (19,841)	$ 1,515,405	$ 1,495,564	$ 1,615,091	$ (119,527)	0.024	0.026
Jun-14	(0.00493)	$ (333,667)	$ 1,664,775	$ 1,331,108	$ 1,703,602	$ (372,494)	0.020	0.025
FYE14		$ (2,356,973)	$ 21,586,774	$ 19,229,800	$ 19,912,643	$ (682,843)		0.023

Source (e): IPL's monthly FCAs
(f) = ((b)-(c))*(e)-0.01053*(c)
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (d)*MN Total Retail Sales/Net Total System Sales; data from kWh sendout in IPL's FYE14 AAA filing.
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Current base cost of energy of $0.02465 per kWh was approved by the Commission's June 22, 2010 Order in Docket No. E001/MR-10-277.

INTERSTATE POWER and LIGHT COMPANY
Summary of Fuel-Cost Recovery Since 1986-1987

Year	Over/(Under) Recovery (%)
1986-87	(0.30)
1987-88	(1.06)
1988-89	0.91
1989-90	(0.90)
1990-91	0.49
1991-92	(0.88)
1992-93	0.89
1993-94	0.18
1994-95	1.80
1995-96	(1.47)
1996-97	(0.18)
1997-98	1.67
1998-99	(2.17)
1999-00	(1.68)
2000-01	(6.66)
2001-02	(0.16)
2002-03	(2.45)
2003-04	(2.57)
2004-05	(2.85)
2005-06	(3.64)
2006-07	0.83
2007-08	0.34
2008-09	(3.97)
2009-10	(1.40)
2010-11	7.90
2011-12	(6.14)
2012-13	3.29
2013-14	(3.43)

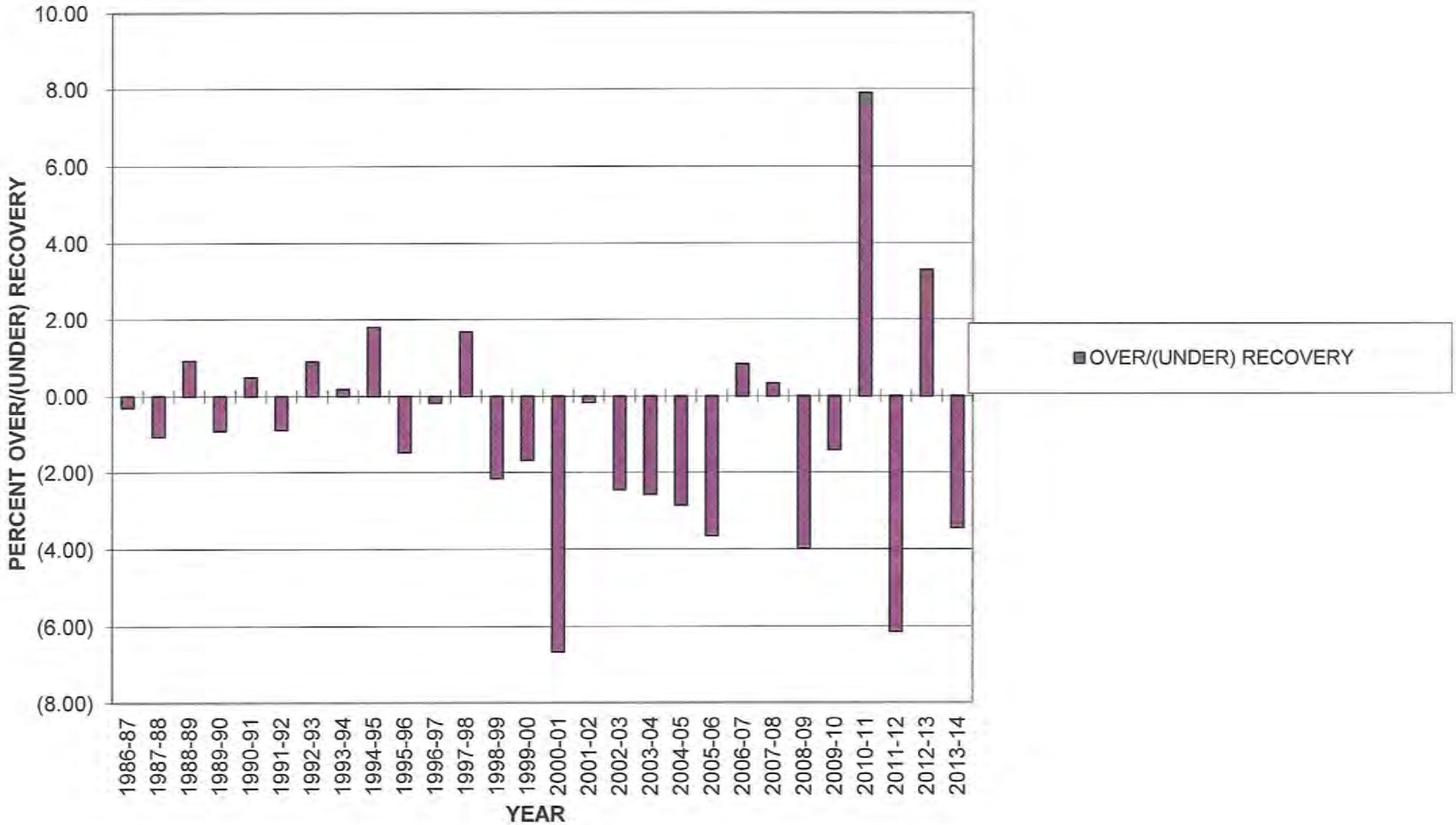
Source: AAA filings

Total Company Recovery, July 2013 - June 2014, By Month

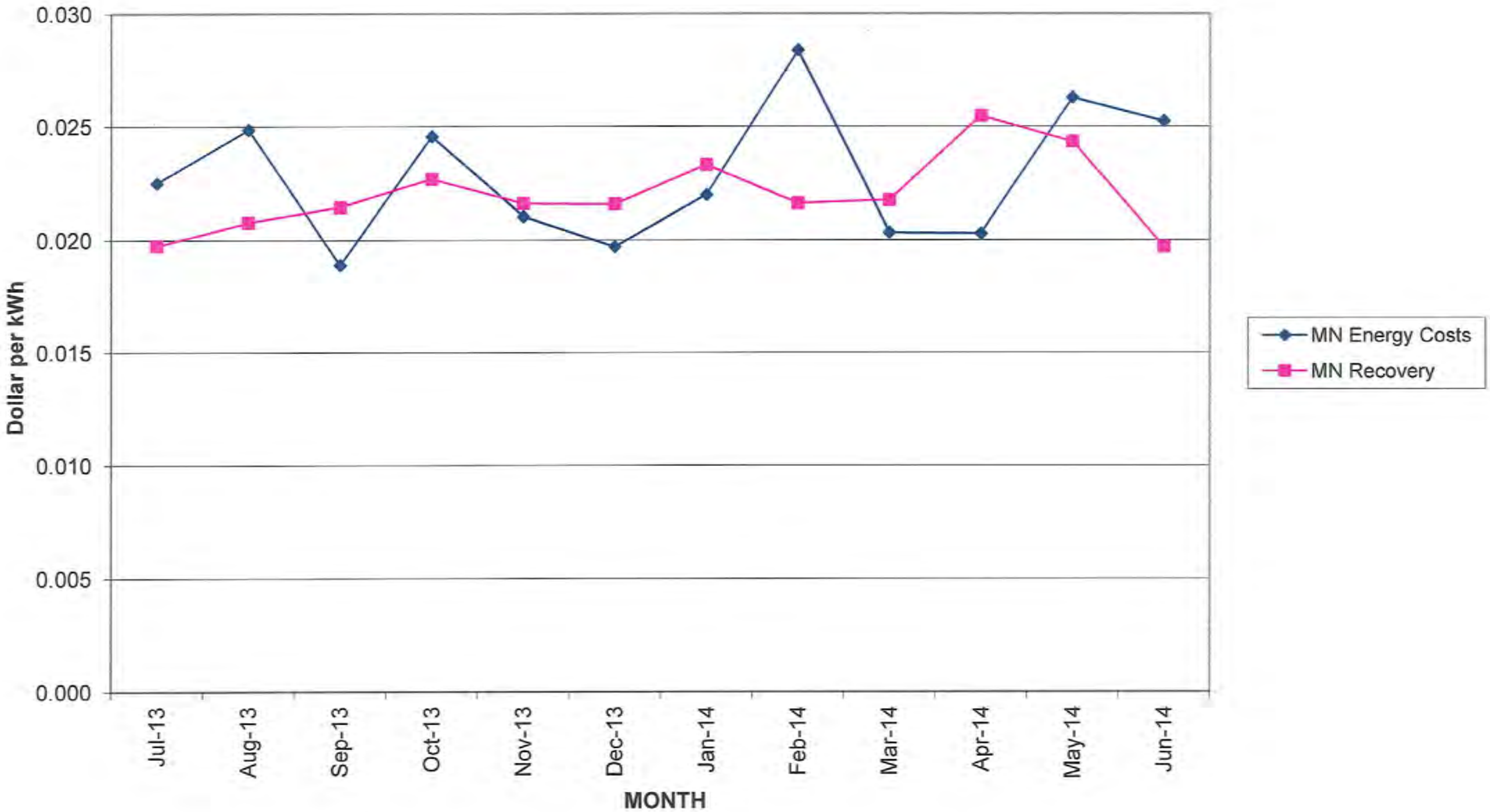
Month	Minnesota Energy Costs (a)	Minnesota Recovery (b)	Over(Under) Recovery (c)	Over(Under) Percentage (d)
July	$ 1,658,982	$1,457,850	($201,133)	(12.12%)
August	$ 1,742,911	$1,457,139	($285,772)	(16.40%)
September	$ 1,524,126	$1,728,754	$204,627	13.43%
October	$ 1,697,514	$1,567,971	($129,543)	(7.63%)
November	$ 1,551,211	$1,593,568	$42,357	2.73%
December	$ 1,619,429	$1,772,405	$152,976	9.45%
January	$ 1,886,550	$2,001,068	$114,518	6.07%
February	$ 2,175,590	$1,656,398	($519,192)	(23.86%)
March	$ 1,443,596	$1,544,172	$100,575	6.97%
April	$ 1,294,040	$1,623,805	$329,765	25.48%
May	$ 1,615,091	$1,495,564	($119,527)	(7.40%)
June	$ 1,703,602	$1,331,108	($372,494)	(21.87%)
Total	**$ 19,912,643**	**$19,229,800**	**($682,843)**	**(3.43%)**

Source (a) and (b): Attachment.
(c) = (b) - (a)
(d)= (c)/(a)

Energy Cost Over(Under) Recovery
Interstate Power and Light Company



INTERSTATE POWER and LIGHT COMPANY'S Energy Costs and Recovery
July 2013-June 2014



Attachment E11

Minnesota Power: FYE14 Energy Cost Over/Under-Recovery

MP	kWh Retail & Firm Resale (a)	FCA Retail Sales (b)	System Costs (c)
Jul-13	899,653,681	757,483,950	$18,660,978
Aug-13	891,670,386	747,780,331	$ 18,546,772
Sep-13	873,723,734	743,749,681	$ 20,882,202
Oct-13	842,408,554	703,943,076	$17,284,583
Nov-13	864,144,871	720,912,072	$ 19,138,910
Dec-13	923,776,823	756,231,558	$ 21,900,238
Jan-14	1,012,778,830	853,969,422	$ 24,778,233
Feb-14	869,700,840	730,921,410	$ 16,566,414
Mar-14	903,931,952	760,213,529	$ 20,074,168
Apr-14	887,838,221	759,711,194	$ 18,805,323
May-14	835,674,072	708,551,078	$ 19,809,148
Jun-14	837,617,696	712,287,549	$ 16,149,139
FYE14	10,642,919,660	8,955,754,850	$ 232,596,108

Source (a): MP's monthly FCAs
Source (b): MP's monthly FCAs.
Source (c): MP's monthly FCAs

Minnesota base cost ($/kWh): July 13 - June 14 0.01018

MP	FCA # 16 Recovery (d)	Old FCA # 16 Recovery (e)	Old FCA # 17 Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-13	8,289,679	$ -	-	$ 7,687,779	$ 15,977,458	$ 15,710,217	$ 267,241	0.021	0.021
Aug-13	7,329,058	$ -	-	$ 7,588,160	$ 14,917,218	$ 15,553,831	$ (636,613)	0.020	0.021
Sep-13	7,285,137	$ -	-	$ 7,558,897	$ 14,844,035	$ 17,775,617	$ (2,931,583)	0.020	0.024
Oct-13	7,428,088	$ -	-	$ 7,140,915	$ 14,569,002	$ 14,444,912	$ 124,090	0.021	0.021
Nov-13	8,740,272	$ -	-	$ 7,321,064	$ 16,061,337	$ 15,968,202	$ 93,134	0.022	0.022
Dec-13	9,129,570	$ -	-	$ 7,705,092	$ 16,834,663	$ 17,930,250	$ (1,095,588)	0.022	0.024
Jan-14	9,583,798	$ -	-	$ 8,740,397	$ 18,324,196	$ 20,896,632	$ (2,572,436)	0.021	0.024
Feb-14	9,378,433	$ -	-	$ 7,473,425	$ 16,851,858	$ 13,924,053	$ 2,927,805	0.023	0.019
Mar-14	10,582,295	$ -	-	$ 7,737,165	$ 18,319,460	$ 16,884,342	$ 1,435,117	0.024	0.022
Apr-14	8,973,488	$ -	-	$ 7,751,784	$ 16,725,272	$ 16,090,683	$ 634,589	0.022	0.021
May-14	7,400,701	$ -	-	$ 7,185,914	$ 14,586,614	$ 16,792,661	$ (2,206,046)	0.021	0.024
Jun-14	8,189,138	$ -	-	$ 7,235,401	$ 15,424,539	$ 13,732,904	$ 1,691,635	0.022	0.019
FYE14	$ 102,309,658	$ -	$ -	$ 91,125,994	$ 193,435,652	$ 195,704,305	$ (2,268,653)	0.022	0.022

Source (d-g): Department's calculations based on data provided in MP's monthly FCAs.
(h) = SUM(d:g)
(i)=(b)*(c)/(a)
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

MINNESOTA POWER
Summary of Fuel-Cost Recovery Since 1986-1987

Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	(1.82)		
1987-88	(1.24)	(1.53)	
1988-89	7.39	1.44	
1989-90	(0.43)	0.98	
1990-91	(3.33)	0.11	
1991-92	0.55	0.19	
1992-93	0.85	0.28	
1993-94	5.03	0.88	
1994-95	(2.33)	0.52	
1995-96	2.25	0.69	
1996-97	(1.63)	0.49	
1997-98	(4.98)	0.03	
1998-99	1.20	0.12	
1999-00	(0.84)	0.05	
2000-01	(4.64)	(0.26)	
2001-02	1.38	(0.16)	
2002-03	(0.56)	(0.19)	(0.51)
2003-04	(7.21)	(0.58)	(1.74)
2004-05	5.99	(0.23)	(0.90)
2005-06	(5.42)	(0.49)	(1.67)
2006-07	(6.98)	(0.80)	(2.21)
2007-08	6.17	(0.48)	(1.09)
2008-09	2.22	(0.36)	(0.99)
2009-10	(0.30)	(0.36)	(0.94)
2010-11	0.47	(0.33)	(0.42)
2011-12	(2.32)	(0.41)	(0.79)
2012-13	0.32	(0.38)	(0.69)
2013-14	(1.16)	(0.35)	(0.73)

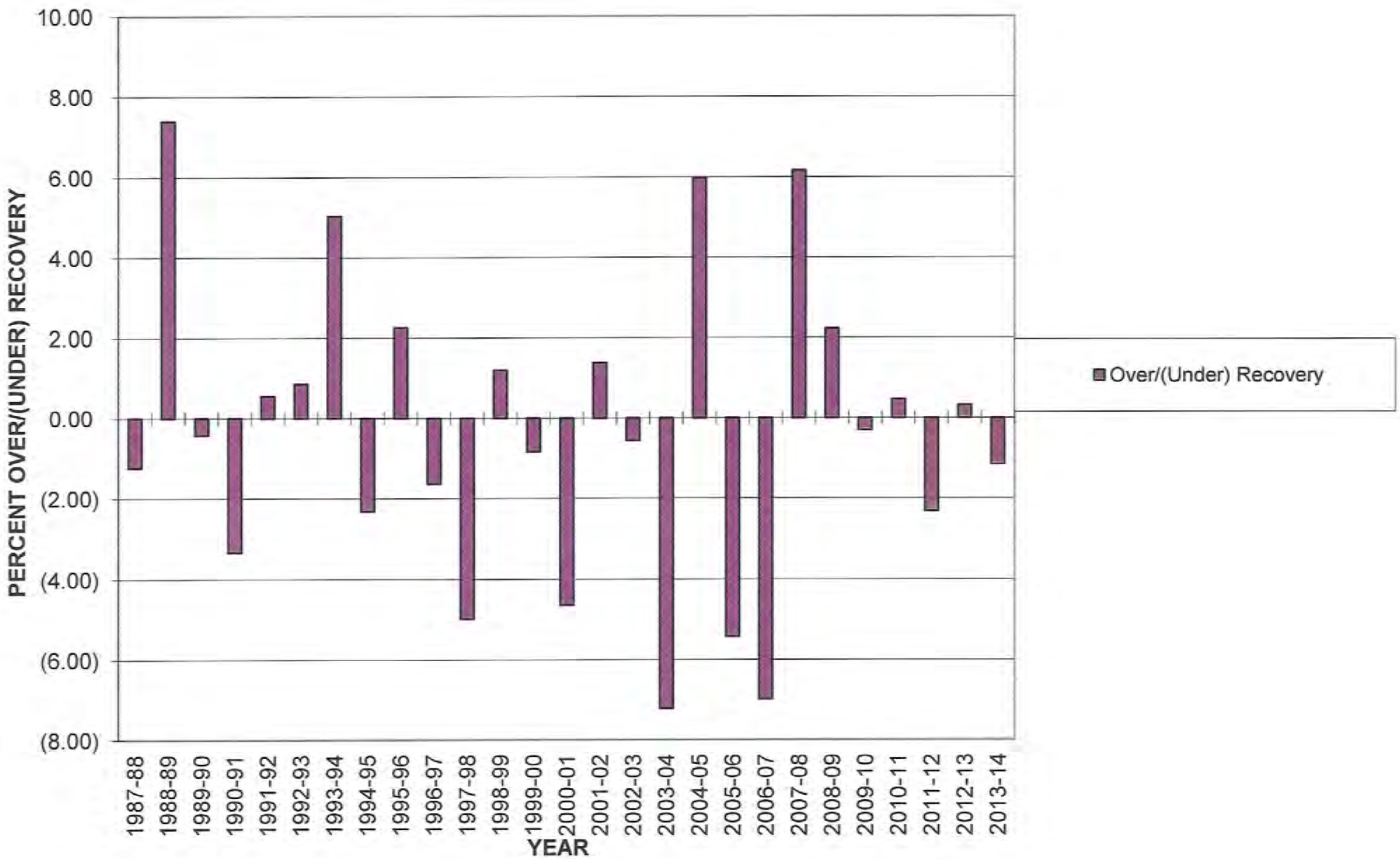
Source: Previous AAA filings up to June 2014 and table below for FYE14 data.

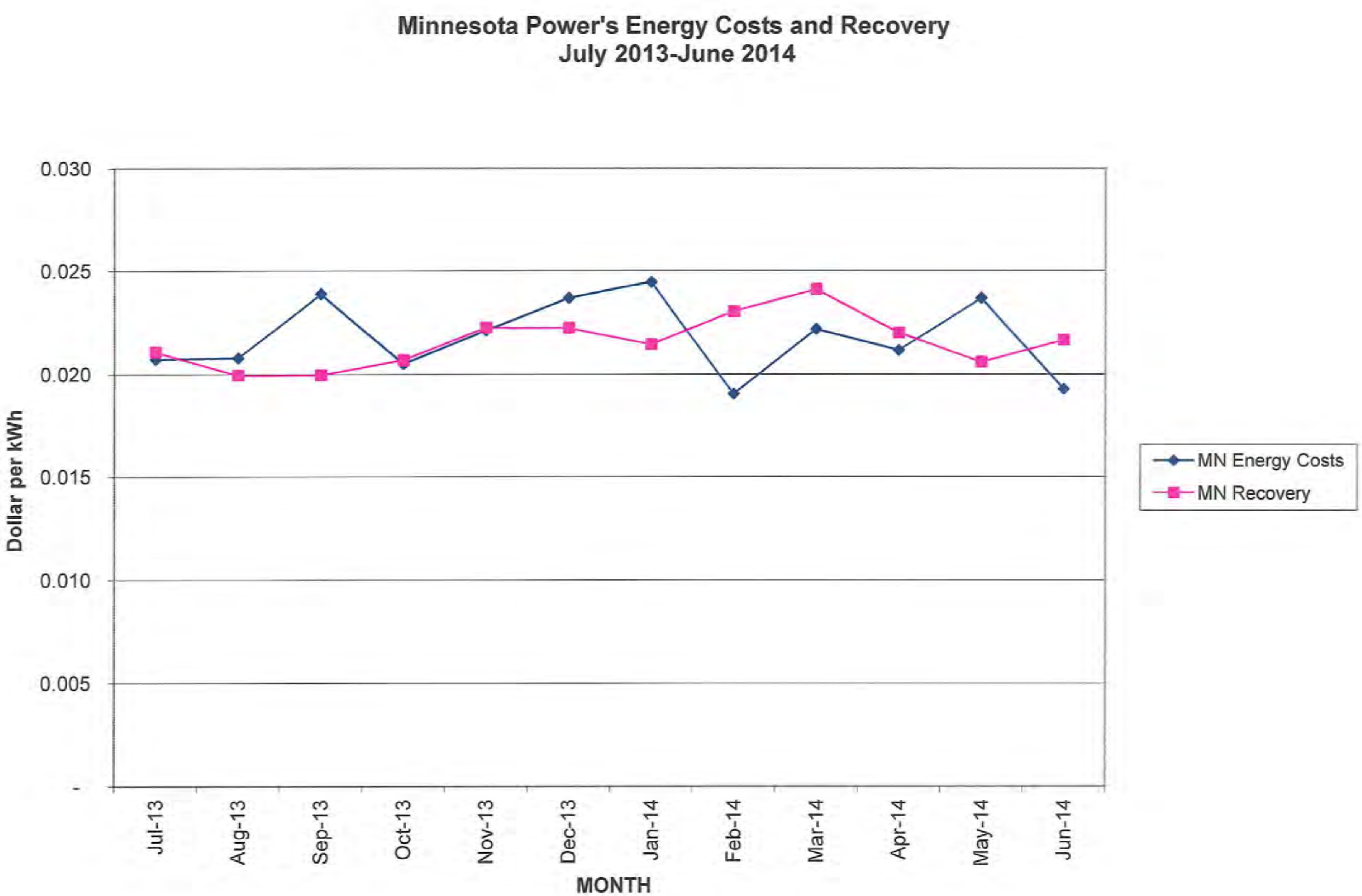
Total Company Recovery, July 2013 - June 2014, By Month

Month	Minnesota Energy Costs	Minnesota Recovery	Over(Under) Recovery	Over(Under) Percentage
	(a)	(b)	(c)	(d)
July	$ 15,710,217	$15,977,458	$267,241	1.70%
August	$ 15,553,831	$14,917,218	($636,613)	(4.09%)
September	$ 17,775,617	$14,844,035	($2,931,583)	(16.49%)
October	$ 14,444,912	$14,569,002	$124,090	0.86%
November	$ 15,968,202	$16,061,337	$93,134	0.58%
December	$ 17,930,250	$16,834,663	($1,095,588)	(6.11%)
January	$ 20,896,632	$18,324,196	($2,572,436)	(12.31%)
February	$ 13,924,053	$16,851,858	$2,927,805	21.03%
March	$ 16,884,342	$18,319,460	$1,435,117	8.50%
April	$ 16,090,683	$16,725,272	$634,589	3.94%
May	$ 16,792,661	$14,586,614	($2,206,046)	(13.14%)
June	$ 13,732,904	$15,424,539	$1,691,635	12.32%
Total	**$ 195,704,305**	**$193,435,652**	**($2,268,653)**	**(1.16%)**

Source: Department's calculations.
(c) = (b) - (a)
(d)= (c)/(a)

Energy Cost Over(Under) Recovery
Minnesota Power




Minnesota Power's Energy Costs and Recovery
July 2013-June 2014
0.030
0.025
0.020
0.015
0.010
0.005
-
Dollar per kWh
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
MONTH
MN Energy Costs
MN Recovery

Attachment E12

Otter Tail Power Company: FYE14 Energy Cost Over/Under-Recovery

OTP	kWh Retail & Firm Resale (a)	Sales Subject to FCA (kWh) (b)		System Costs (c)
Jul-13	321,839,019	164,008,554	$	7,515,150
Aug-13	322,294,353	168,264,951	$	7,510,321
Sep-13	334,847,999	170,799,713	$	6,376,288
Oct-13	307,992,771	156,313,809	$	7,055,944
Nov-13	383,072,284	187,160,553	$	8,634,705
Dec-13	440,220,452	206,161,462	$	13,170,243
Jan-14	517,245,284	239,225,081	$	11,901,987
Feb-14	489,675,847	228,635,561	$	12,082,316
Mar-14	435,798,783	203,763,989	$	13,596,282
Apr-14	409,245,261	197,565,461	$	7,375,402
May-14	348,741,321	172,596,249	$	10,007,786
Jun-14	325,543,407	169,304,676	$	8,863,803
FYE14	4,636,516,781	2,263,800,059	$	114,090,227

Source (a): OTP's July 31, 2014 compliance report approved by the Commission's September 25, 2014 Order in Docket No. E017/M-03-30.
Source (b): OTP's July 31, 2014 compliance report approved by the Commission's September 25, 2014 Order in Docket No. E017/M-03-30.
Source (c): OTP's July 31, 2014 compliance report approved by the Commission's September 25, 2014 Order in Docket No. E017/M-03-30.

MN Base Cost (($/kWh) 0.023163

OTP	Net FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over (Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-13	$ (324,059)	$ 3,798,930	$ 3,474,871	$ 3,669,306	$ (194,434)	0.021	0.022
Aug-13	$ 99,051	$ 3,897,521	$ 3,996,572	$ 3,666,948	$ 329,624	0.024	0.022
Sep-13	$ 29,221	$ 3,956,234	$ 3,985,455	$ 3,113,251	$ 872,204	0.023	0.018
Oct-13	$ 25,053	$ 3,620,697	$ 3,645,750	$ 3,445,096	$ 200,654	0.023	0.022
Nov-13	$ (378,452)	$ 4,335,200	$ 3,956,748	$ 4,215,933	$ (259,185)	0.021	0.023
Dec-13	$ (466,614)	$ 4,775,318	$ 4,308,704	$ 6,430,430	$ (2,121,726)	0.021	0.031
Jan-14	$ (111,014)	$ 5,541,171	$ 5,430,157	$ 5,811,198	$ (381,042)	0.023	0.024
Feb-14	$ 755,669	$ 5,295,885	$ 6,051,554	$ 5,899,245	$ 152,310	0.026	0.026
Mar-14	$ 613,255	$ 4,719,785	$ 5,333,040	$ 6,638,446	$ (1,305,405)	0.026	0.033
Apr-14	$ 130,206	$ 4,576,209	$ 4,706,415	$ 3,601,073	$ 1,105,342	0.024	0.018
May-14	$ 788,189	$ 3,997,847	$ 4,786,036	$ 4,886,346	$ (100,310)	0.028	0.028
Jun-14	$ 277,053	$ 3,921,604	$ 4,198,657	$ 4,327,791	$ (129,134)	0.025	0.026
FYE14	$ 1,437,558	$ 52,436,401	$ 53,873,959	$ 55,705,064	$ (1,831,105)		0.025

Source (f): OTP's July 31, 2014 compliance report approved by the Commission's September 25, 2014 Order in Docket No. E017/M-03-30.
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (c)*Total Revised Sales Subject to FCA/Net Total System Sales
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Note:
Current base cost of energy of $0.023163 per kWh was approved by the Commission's May 27, 2010 Order in Docket No. E017/MR-10-240.

Total Company Recovery, July 2013- June 2014, By Month

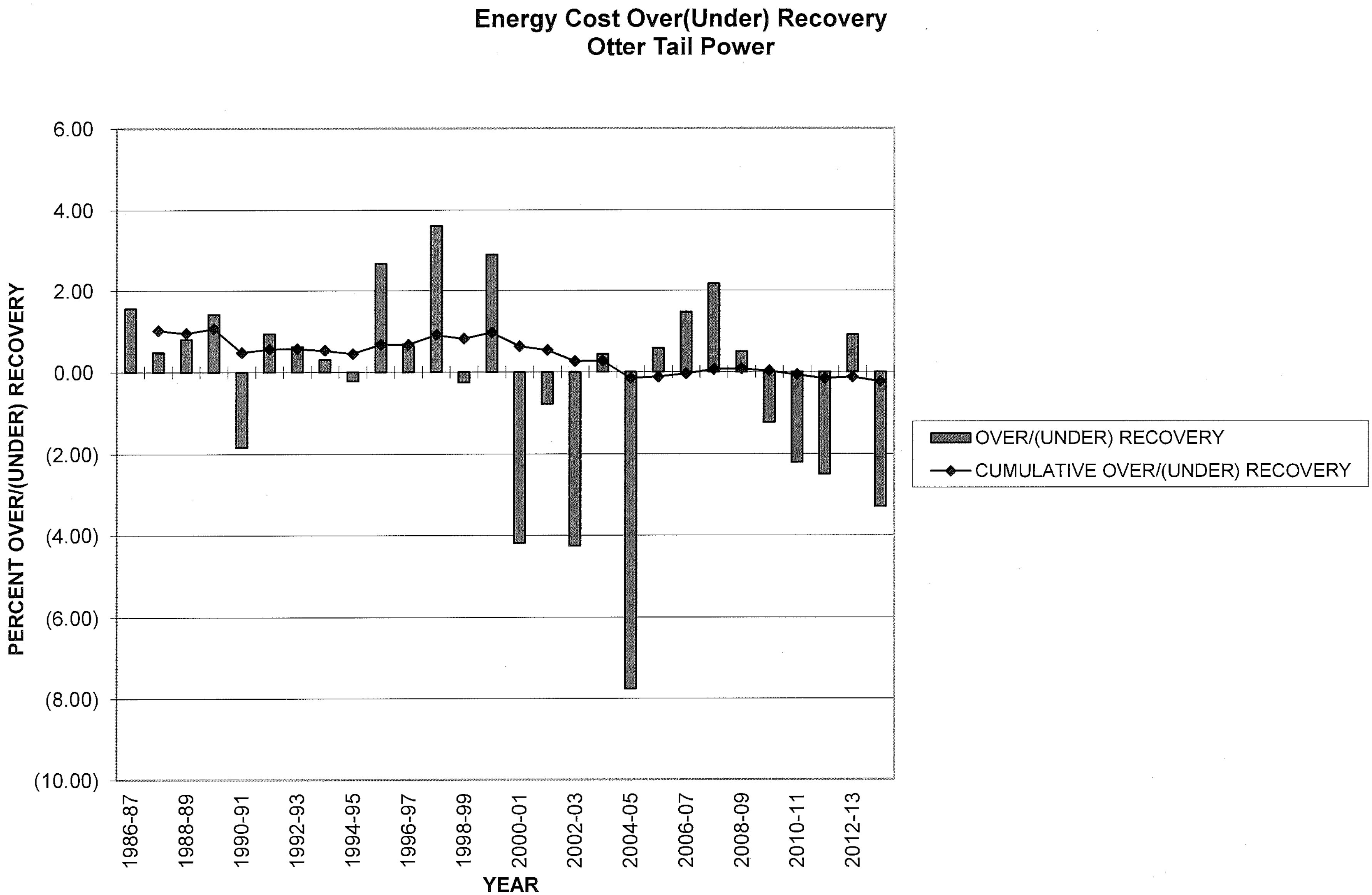
Month	Minnesota Energy Costs	Minnesota Recovery	Over(Under) Recovery	Over(Under) Percentage
	(a)	(b)	(c)	(d)
July	$ 3,669,306	$3,474,871	($194,434)	(5.30%)
August	$ 3,666,948	$3,996,572	$329,624	8.99%
September	$ 3,113,251	$3,985,455	$872,204	28.02%
October	$ 3,445,096	$3,645,750	$200,654	5.82%
November	$ 4,215,933	$3,956,748	($259,185)	(6.15%)
December	$ 6,430,430	$4,308,704	($2,121,726)	(33.00%)
January	$ 5,811,198	$5,430,157	($381,042)	(6.56%)
February	$ 5,899,245	$6,051,554	$152,310	2.58%
March	$ 6,638,446	$5,333,040	($1,305,405)	(19.66%)
April	$ 3,601,073	$4,706,415	$1,105,342	30.69%
May	$ 4,886,346	$4,786,036	($100,310)	(2.05%)
June	$ 4,327,791	$4,198,657	($129,134)	(2.98%)
Total	**$ 55,705,064**	**$53,873,959**	**($1,831,105)**	**(3.29%)**

Source: Attachment.
(c) = (b) - (a)
(d)= (c)/(a)

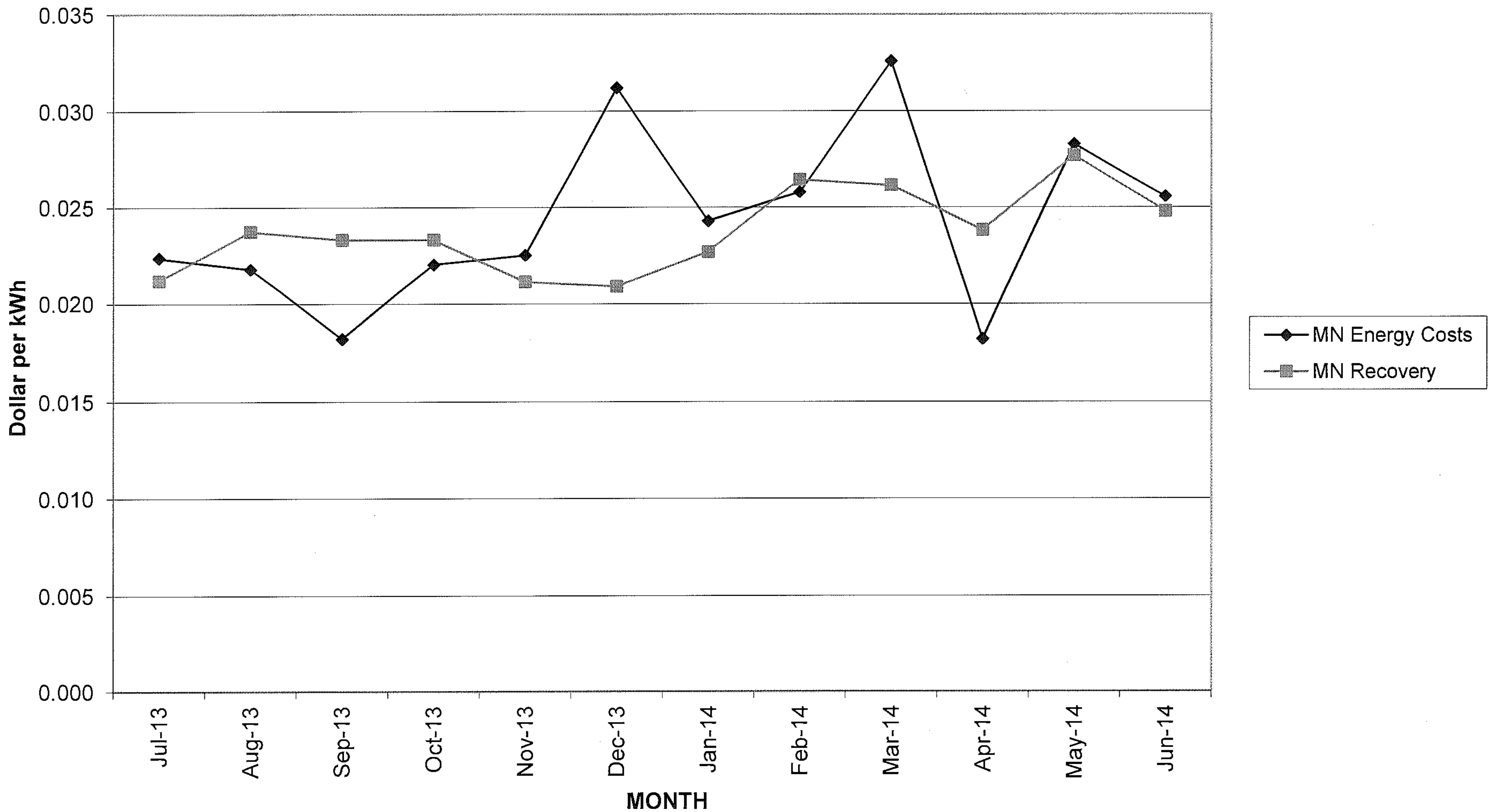
OTTER TAIL POWER COMPANY
Summary of Fuel-Cost Recovery Since 1986-1987

Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	1.56		
1987-88	0.48	1.02	
1988-89	0.80	0.95	
1989-90	1.41	1.06	
1990-91	(1.83)	0.48	
1991-92	0.93	0.56	
1992-93	0.62	0.57	
1993-94	0.30	0.53	
1994-95	(0.22)	0.45	
1995-96	2.67	0.67	
1996-97	0.63	0.67	
1997-98	3.62	0.91	
1998-99	(0.25)	0.82	
1999-00	2.90	0.97	
2000-01	(4.19)	0.63	
2001-02	(0.77)	0.54	
2002-03	(4.26)	0.26	0.04
2003-04	0.44	0.27	0.06
2004-05	(7.76)	(0.15)	(0.70)
2005-06	0.58	(0.12)	(0.91)
2006-07	1.47	(0.04)	(0.82)
2007-08	2.17	0.06	(0.97)
2008-09	0.50	0.08	(0.89)
2009-10	(1.22)	0.02	(1.30)
2010-11	(2.20)	(0.06)	(1.11)
2011-12	(2.49)	(0.16)	(1.28)
2012-13	0.91	(0.12)	(0.76)
2013-14	(3.29)	(0.23)	(1.13)

Source: Previous AAA filings up to June 2013 and previous table for FYE14 data.


Energy Cost Over(Under) Recovery
Otter Tail Power
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
(10.00)
PERCENT OVER/(UNDER) RECOVERY
1986-87
1988-89
1990-91
1992-93
1994-95
1996-97
1998-99
2000-01
2002-03
2004-05
2006-07
2008-09
2010-11
2012-13
YEAR
OVER/(UNDER) RECOVERY
CUMULATIVE OVER/(UNDER) RECOVERY

OTTER TAIL POWER COMPANY'S Energy Costs and Recovery
July 2013-June 2014



Attachment E13

Xcel Electric: FYE14 Energy Cost Over/Under-Recovery

	Jul 13-Dec 13	Jan 14-Jun 14
Minnesota Base Cost ($/kWh):	0.02729	0.02780

Xcel	**Prior Balance** (a)	**True Up Recovery** (b)	**FCA Recovery** (c)	**Base Cost Recovery** (d)	**Fuel Clause Revenues** (e)	**MN Energy Costs** (f)	**Saver's Switch True Up Adj** (g)	**Balance (Cost-Revenues)** (h)
Jul-13	$ (194,147)	$ (198,169)	$ 10,676,300	$ 82,536,919	$ 93,015,050	$ 92,319,774	$ 195,769	$ (693,654)
Aug-13	$ 1,973,465	$ 2,067,216	$ 4,619,117	$ 82,389,147	$ 89,075,480	$ 85,825,677	$ 103,828	$ (1,172,510)
Sep-13	$ (693,654)	$ (731,644)	$ 2,756,249	$ 71,636,269	$ 73,660,874	$ 78,918,790	$ 35,358	$ 4,599,620
Oct-13	$ (1,172,510)	$ (1,170,419)	$ 2,859,677	$ 66,701,777	$ 68,391,035	$ 75,077,407	$ -	$ 5,513,862
Nov-13	$ 4,599,620	$ 4,628,390	$ 4,464,879	$ 66,221,051	$ 75,314,320	$ 76,934,789	$ -	$ 6,220,089
Dec-13	$ 5,513,862	$ 5,708,921	$ 6,289,721	$ 70,350,586	$ 82,349,228	$ 85,779,869	$ -	$ 8,944,503
Jan-14	$ 6,220,089	$ 6,422,351	$ 3,823,904	$ 73,821,694	$ 84,067,949	$ 90,537,999	$ -	$ 12,690,139
Feb-14	$ 8,944,503	$ 9,314,048	$ 2,264,572	$ 66,972,756	$ 78,551,376	$ 71,843,173	$ -	$ 2,236,300
Mar-14	$ 12,690,139	$ 13,372,363	$ 5,319,454	$ 70,755,131	$ 89,446,948	$ 69,587,791	$ -	$ (7,169,018)
Apr-14	$ 2,236,300	$ 2,259,169	$ 1,495,365	$ 62,985,067	$ 66,739,601	$ 64,943,102	$ -	$ 439,801
May-14	$ (7,169,018)	$ (7,341,626)	$ 4,655,142	$ 66,025,559	$ 63,339,075	$ 61,709,308	$ -	$ (8,798,785)
Jun-14	$ 439,801	$ 447,385	$ 3,946,626	$ 72,658,611	$ 77,052,622	$ 72,963,829	$ 61,348	$ (3,587,644)
FYE14		$ 34,777,985	$ 53,171,006	$853,054,567	$941,003,558	$926,441,508		

1. FYE14 cumulative under-recovery	$ (12,386,428)
2. FYE13 cumulative under-recovery	$ 1,779,319
3. FYE14 under-recovery = (1)-(2)	$ (14,165,747)
	1.53%

(a) = (h) with a two-month lag.
Source (b), (c), (d) & (f): Xcel's monthly FCA data with further Department calculations under the Department's review of the monthly FCAs.
(e) = (b) + (c) + (d)
Source (g): Xcel's monthly FCAs. More info on the Saver's Switch discount program is provided in
Xcel's May 7, 2007 Supplemental Information Compliance filing in Docket No. E002/GR-05-1428.
(h) = (a) - (e) + (f) + (g)

Note:
Xcel's FCA factor is the ratio of (system costs - intersystem sales - Windsource costs) by (system retail MWh, resale MWh and Windsource MWh).
Minnesota costs are the product of the FCA factor by MN sales (MWh) subject to FCA factor (retail minus Windsource).
Xcel's FCA revenues are calculated on the basis of MN sales (MWh) subject to FCA factor.

Attachment E14

Otter Tail Power Company response to the Department's discovery regarding MISO Day 2

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/13/2015
Date Due: 03/25/2015
Date of Response: 03/25/2015
Responding Witness: Stuart Tommerdahl, Manager
Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) MISO Day 2 charges as reported in Attachment K to its 2013-2014 AAA Report. The total 2013-2014 MISO Day 2 Net Costs have increased from $31.4 million in 2012-2013 to $42.2 million in 2013-2014, or a $10.8 million increase.

Please explain why the total 2013-2014 MISO Day 2 net costs have increased by such a large amount from the previous year.

Attachments: 1

Attachment 1 to IR MN-DOC-015.pdf

Response:

The primary factors which drove higher MISO day 2 charges in the 2013-2014 time period were the impacts of weather and its influence on demand for energy and the associated market prices for that energy. The following will highlight these impacts further.

Extremely Cold Winter

The winter of 2013/2014 was one of the coldest winters our region has experienced in the last 20 years due to the "polar vortex" weather pattern which existed across the upper Midwest. The following table compares actual temperatures across OTP's service territory compared to 20 year averages from December 2013 thru April 2014.

	Actual Average Temp	20 Year Average Temp	Deviation from Average
December 2013	3.1	14.9	-11.8
January 2014	3.9	8.9	-4.9
February 2014	3.3	13.9	-10.6
March 2014	20.9	26.2	-5.3
April 2014	37.8	42.0	-4.1

Demand for Energy Up

Due to the cold weather, demand for energy increased throughout MISO during this time. Attachment 1 to this Information Request is a side-by-side comparison of the 2012-2013 and 2013-2014 Attachment K MISO Day 2 Charges (System basis) that summarize the major cost and revenue categories from those reports and helps illustrate the year to year changes in costs and revenues. Line 1 of that table shows Day Ahead (DA) and Real Time (RT) energy (OTP Load) increased from 4,635,473 MWhs in 2013 to 4,959,325 MWhs in 2014, an approximately 7% increase. A majority of this increase was driven by the cold weather influence. Sales from generation also increased from 3,588,873 MWhs in 2013 to 4,075,568 MWhs in 2014, offsetting a portion of the impact from increased load. When loads exceed OTP owned generation and forward contracted amounts for energy, OTP must rely on the DA and RT markets to meet its customer's needs.

Market Prices for Energy Up

A larger influence on the cost increase came from the increase in average energy (LMP) prices in 2014 compared to 2013. As noted in lines 18-20 of Attachment 1, the average energy price increased from the $26-27/MWh range in 2013 to approximately $36/MWh in 2014. Of the $10.8 million in net MISO cost increases for the year, approximately $7.4 million came from the increase in energy (DA and RT) costs. Due to increased volumes of energy purchased and sold, net energy losses also increased approximately $865,000 (Line 2 of Attachment 1, Column J plus Column L) in 2014 compared to 2013.

Attachment 1
Information Request DOC-15
E999/AA-14-579
Otter Tail Power Company

Otter Tail Power Company
Comparative Summary of MISO Day 2 Charges- System
Annual - 2012/2013 vs Annual 2013/2014 Attachment K amounts

			A	B	C	D	E	F	G	H	I	J	K	L
			2014 RETAIL Year to date July 2013 to June 2014				2013 RETAIL Year to date July 2012 to June 2013				Change RETAIL			
Line	Attachment K Reference	Description	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
1	Line 5	DA & RT ENERGY	(4,959,325)	$ (176,449,033)	4,075,568	$ 146,721,961	(4,635,473)	$ (120,334,416)	3,588,873	$ 98,052,843	(323,852)	$ (56,114,617)	486,695	$ 48,669,118
2	Line 12	DA & RT ENERGY LOSS		$ (9,771,029)		$ 4,172,945		$ (8,400,546)		$ 3,667,324		$ (1,370,482)		$ 505,621
3	Line 15	Virtual Energy										$ -		$ -
4	Line 19	Schedules 16 & 17		$ (750,444)		$ 4,120		$ (785,055)		$ 3,214		$ 34,611		$ 906
5	Line 35	Congestion & FTRs		$ (16,875,070)		$ 16,862,351		$ (8,300,892)		$ 8,759,730		$ (8,574,178)		$ 8,102,621
6	Line 41	RSG & Make whole		$ (1,139,957)		$ 565,493		$ (738,182)		$ 467,527		$ (401,775)		$ 97,966
7	Line 46	RNU & Misc		$ (1,581,984)		$ 488,326		$ (1,015,814)		$ 293,677		$ (566,170)		$ 194,650
8	Line 49	ASM	(369,696)	$ (10,225,097)	144,002	$ 4,294,602	(306,697)	$ (7,005,940)	114,594	$ 2,517,058	(62,999)	$ (3,219,158)	29,408	$ 1,777,545
9	Line 54	Grandfathered Charge Types												
10	Line 55	Total MISO Day 2 Charges	(5,329,021)	$ (216,792,615)	4,219,570	$ 173,109,798	(4,942,170)	$ (146,580,846)	3,703,467	$ 113,761,373	(386,851)	$ (70,211,769)	516,103	$ 59,348,426
11	Line 56	Less: 16 & 17		$ (750,444)		$ 4,120		$ (785,055)		$ 3,214		$ 34,611		$ 906
12	Line 57	Congestion & Losses Adjustment		$ (385,528)				$ (561,570)				$ 176,042		$ -
13	Line 58	No DA gen schedul but still had output for current month		$ (324,417)				$ (58,423)				$ (265,994)		$ -
14	Line 59	Total for MN Energy Adjustment Rider		$ (215,332,226)		$ 173,113,918		$ (145,175,798)		$ 113,764,587		$ (70,156,428)		$ 59,349,331
15	Line 61	Net Retail for MN Energy Adjustment Rider			$ (42,218,308)				$ (31,411,211)				$ (10,807,097)	
16														
17														
18		DA & RT ENERGY ($) (Line 1 above)		$ (176,449,033)		$ 146,721,961		$ (120,334,416)		$ 98,052,843				
19		DA & RT ENERGY (MWhs) Line 1 above		(4,959,325)		4,075,568		(4,635,473)		3,588,873				
20		Average Energy price/MWh (DA & RT Energy) $/MWh		$ 35.58		$ 36.00		$ 25.96		$ 27.32				
21		Average DA/RT Energy Loss/ MWh		$ 1.97		$ 1.02		$ 1.81		$ 1.02				

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/13/2015
Date Due: 03/25/2015
Date of Response: 03/25/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) total for Day Ahead and Real Time Energy from July 2013 to June 2014, as reported in Attachment K to its 2013-2014 AAA Report, increased by approximately $55.4 million with an increase in revenues of approximately $48.0 million as compared to the previous year's filing. The majority of the increased costs appear to be related to increase Day Ahead Asset Energy amount.

Please explain why the Company incurred increased Day Ahead and Real time Energy costs in the July 2013 to June 2014 as compared to the previous year, and why these costs are appropriately assigned to retail customers.

Attachments: 0

Response:

As outlined and discussed in OTP's response to MN-DOC-015, the increase in Day Ahead (DA) and Real Time (RT) energy costs and revenues were primarily driven by increased demands for energy that resulted from the colder than normal weather conditions during the December 2013 to March 2014 timeframe, and the associated increase in energy prices that resulted from those increased demands as higher cost marginal units were dispatched within the MISO market.

As a market participant within MISO and by the nature of how the MISO market operates, OTP schedules its load into the MISO market and acquires the energy to meet its load each day. OTP also offers its generation resources into the market daily, with the revenues received from the dispatch of its generation being credited back to the retail customers. When loads exceed the output of owned generation and other purchased power sources of energy, customer's remaining energy needs are fulfilled in the DA and RT markets.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
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Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) total for Congestion & FTRs from July 2013 to June 2014, as reported in Attachment K to its 2013-2014 AAA Report, increased by approximately $8.5 million with an increase in revenues of approximately $8.8 million as compared to the previous year's filing. These values represent almost a doubling of the corresponding values from July 2012 to June 2013. The majority of the increases in costs appear to be related to an increase in the FTR Annual Transaction Amount while the majority of the increase in revenue appears to be related in an increase in the FTR Auction Revenue Rights Transaction Amount.

Please explain why the Company incurred increased Congestion & FTRs costs and revenues in the July 2013 to June 2014 as compared to the previous year.

Attachments: 0

Response:

A Market Participant (MP) receives Candidate Auction Revenue Rights based on its historical use of the transmission system. These rights can be nominated and may be allocated to the individual MP by MISO as either feasible or infeasible Auction Revenue Rights (ARRs). Feasible ARRs can then be self-scheduled into the Annual FTR Auction to complete the day-ahead hedge.

ARRs are valued based on the MISO clearing of the Annual FTR Auction. Self-scheduled FTRs will have the same auction value in magnitude as their corresponding Auction Revenue Rights but with opposite signage. The Self-scheduled FTRs will also continue to settle daily, based on the day-ahead congestion values.

Otter Tail Power Company (OTP) chooses to self-schedule all feasible, allocated, Auction Revenue Rights received in order to complete the day-ahead congestion hedge available to it. As a result, when reviewing the Retail portion of the AAA Reports, the costs/revenues associated with the FTR Auction Revenue Rights Transaction Amount will nearly offset the FTR Annual Transaction Amount. Some minor differences may be noted due to ARRs that were allocated as infeasible and therefore ineligible under the MISO market rules to be self-scheduled to an FTR.

Yearly fluctuations in the MISO auction clearing values of the individual paths will produce different levels of costs/revenues, but the net will remain very close to zero. The addition of rows 30 and 31 within the Retail section for each individual reporting year will show this clearly.

In addition, OTP changed the treatment of its GFAs on Big Stone and Coyote in June 2013 from Option B to Option A. Under Option B treatment, OTP did not receive any ARRs or FTRs for these entitlements, but rather received a congestion rebate based on its day-ahead, financial, bilateral, schedule. As a result, these paths produced no auction costs/revenues. MISO tracked the congestion entitled to rebate on the Option B GFAs under the DA FBT Congestion Amount and the DA Congestion Rebate.

Beginning, in June 2013, the Option A treatment allowed OTP to request, receive, and nominate ARRs from these units and self-schedule the ARRs to FTRs. Therefore, these paths began producing auction costs/revenues and these values were reported by MISO in the FTR Auction Revenue Rights Transaction Amount and the FTR Annual Transaction Amount as documented in the 2013-2014 AAA report. The congestion associated with the Option A FTRs were no longer singled out under separate line items by MISO, but rather, MISO began reporting it under the FTR Hourly Allocation Amount.

The other differences between the net retail totals are due to fluctuations in MISO market congestion from one year to the next, as well as differences in MISO market uplifts and true-ups.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/13/2015
Date Due: 03/25/2015
Date of Response: 03/25/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) Attachment K to its 2013-2014 AAA Report indicated that between December 2013 and March 2014 Day Ahead & Real Time Energy, Day Ahead & Real Time Energy Loss, Congestion and FTRs, and ASM Charges were substantially higher in both costs and revenues than the same period in the previous year.

Please explain why the Company incurred such large increases in Costs and Revenues during this period, and why these costs are appropriately assigned to retail customers.

Attachments: 0

Response:

As outlined in responses to information requests MN-DOC-15 and MN-DOC-16, the increase in costs and revenues, as described above, were driven by system wide cold weather conditions during the months of December 2013 through March of 2014 and corresponding increases in prices. Specifically, during these months, the average 24-hour day ahead LMP pricing at the OTP load zone increased from $28.46 per MWhr in 2012/13 to $50.18 per MWhr in 2013/14. The increased LMP pricing directly impacts the magnitude of the charge types listed above. These cost (and revenue) increases are a function of participation and operation within the MISO market.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/13/2015
Date Due: 03/25/2015
Date of Response: 03/25/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) Attachment K to its 2013-2014 AAA Report indicated that OTP's FTR Hourly Allocation Amount costs totaled $2,395,984.37 in May, 2014. This amount is significantly higher than the costs charged to other months during the 2013-2014 AAA reporting period.

Please explain why the Company incurred such large FTR Hourly Allocation Amount costs in May, 2014 and why these costs are appropriately assigned to retail customers.

Attachments: 0

Response:

Since the beginning of the MISO market, OTP has been awarded and self-schedules FTRs between its generating facilities and its load zone to provide a hedge for congestion charges between those points. The portfolio of FTRs entitle OTP to hourly congestion revenues experienced on the FTR paths, and obligates OTP to hourly congestion costs experienced on the FTR paths. Congestion revenues and expenses fluctuate hourly due to changing market conditions related to demands for energy as well as generation and transmission resource availability.

Regarding the costs in question in this information request, please note that the dates included in the OTP May 2014 accounting month actually begin with the MISO operating date of April 23, 2014. From April 23, 2014 to May 2, 2014, a binding constraint on the transmission system caused the value of the associated Hoot Lake Plant sourced FTRs to be largely negative. As noted above, a combination of factors can contribute to a binding constraint including demand for energy as well availability of generation and transmission facilities. The binding constraint that impacted the FTRs in this case correlates to a transmission maintenance outage that occurred on an area 230 kV line during the dates noted above. When the line returned to service, the constraint went away. The negative value of these paths for the duration of the event decreased the value of the FTR portfolio for the month. At the conclusion of the event, the value of the paths moderated.

Collectively during the 2013-2014 reporting period, OTP's total revenues and costs associated with its retail FTR portfolio were nearly equal. As reflected in the summary included in Attachment 1 to MN-DOC-15 line 5 (Also found in Attachment K, Line 35, which encompasses all elements of the Congestion and FTR activity in lines 20-34), OTP's total retail costs for Congestion and FTRs were ($16,875,070) and total retail revenues were $16,862,351, a net cost of ($12,719).

OTTER TAIL POWER COMPANY
Docket No: E999-AA-14-579

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/13/2015
Date Due: 03/25/2015
Date of Response: 03/25/2015
Responding Witness: Stuart Tommerdahl, Manager Regulatory Administration, 218 739-8279

Information Request:

Reference: Otter Tail Power's (OTP) allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's Review of the 2010-2011 Annual Automatic Adjustment Reports.[1] In the reply comments in the 2012-2013 Annual Automatic Adjustment Reports[2] the Company stated that there were no changes in its allocation method since the previous report.

Please explain if any of the Company's allocation methods have changes during the 2013-2014 reporting period.

Please explain the nature of any changes and the effects these changes have had on the charges assigned to various customer categories in the 2013-2014 AAA Report.

Attachments: 0

Response:

There were no changes to OTP's allocation methods during the 2013-2014 reporting period.

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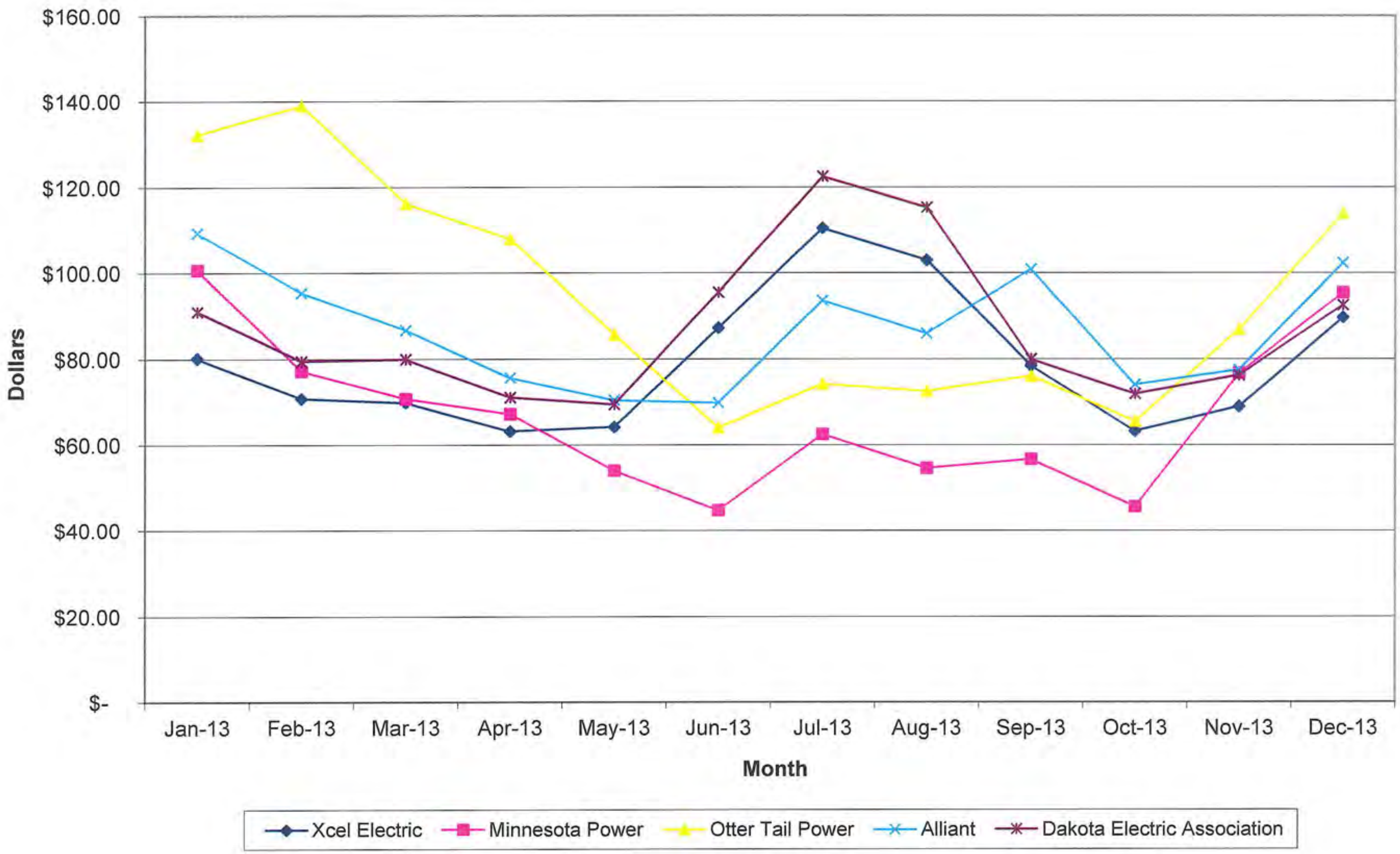
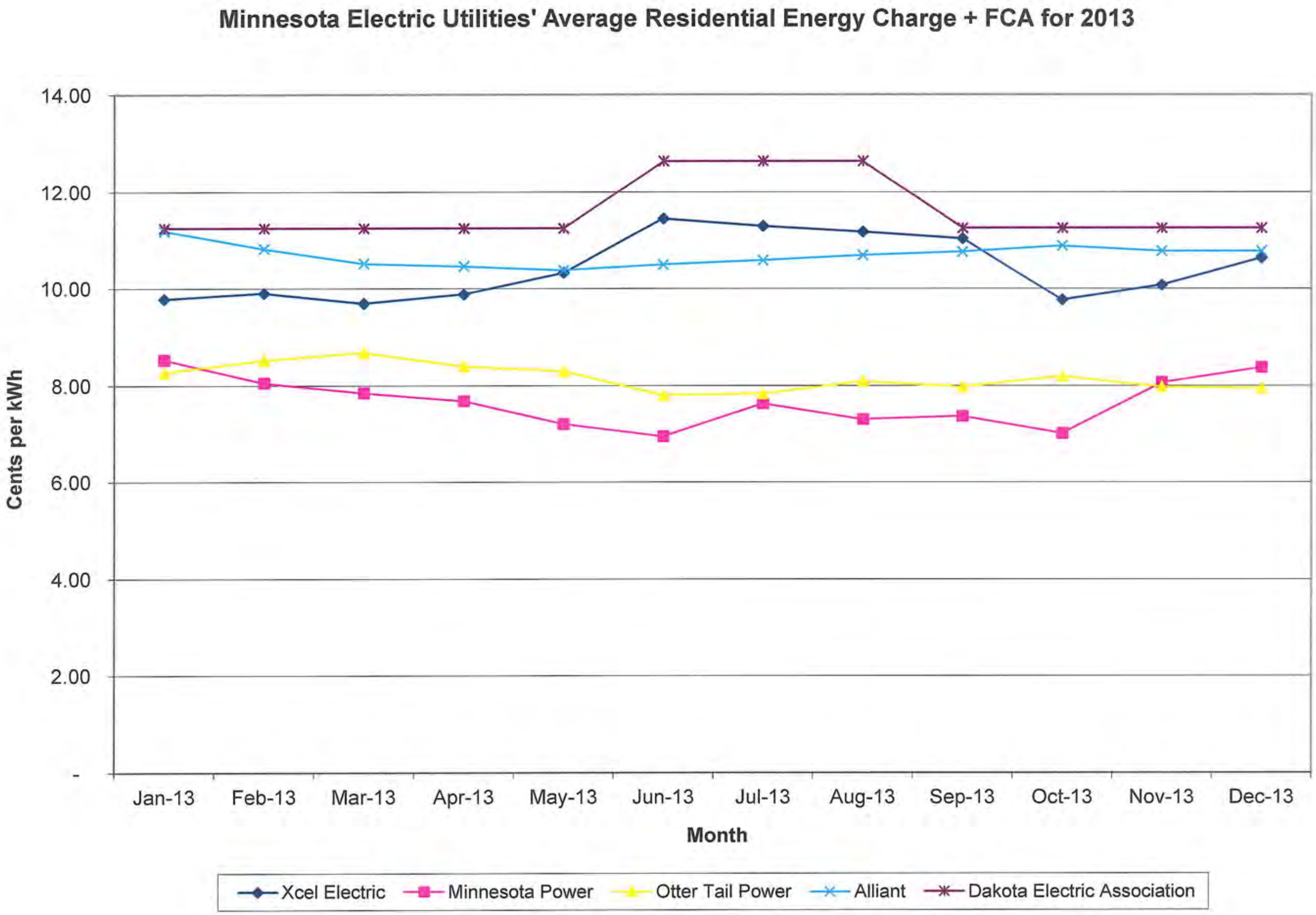
1 The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.
2 The Company's reply comments for the *2011-2012 Annual Automatic Adjustment Reports* was filed September 20, 2013 in Docket No. E999/AA-12-757.

Attachment E15

Minnesota Electric Utilities' Average Residential Bills for 2013

Minnesota Electric Utilities' Average Residential Bills for 2013




Minnesota Electric Utilities' Average Residential Energy Charge + FCA for 2013
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Cents per kWh
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
Month
Xcel Electric
Minnesota Power
Otter Tail Power
Alliant
Dakota Electric Association

Minnesota Electric Utilities' Average Residential Bills for 2013

Xcel Electric		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Monthly Av.
Av. residential monthly kWh usage		733	632	636	558	543	688	901	844	636	564	603	746	674
(1) Number of customers		1,101,910	1,102,637	1,103,311	1,104,265	1,104,149	1,103,632	1,104,668	1,105,760	1,106,060	1,107,410	1,108,403	1,109,646	1,105,154
(1) Residential sales (MWh)		807,846	696,650	701,598	615,888	600,038	759,238	994,885	932,832	703,208	624,892	668,319	828,179	744,464
(2) Customer Charge		$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 7.11	$ 8.00	
(2) Energy charge ($/kWh)														
Jan-May and Oct, Nov	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0821	0.0821	0.0821	0.0821	0.0698	0.0698	0.0739	
June.-Sept	0.0821													
Dec	0.0739													
En. Charge X kWh usage		$ 51.14	$ 44.07	$ 44.35	$ 38.90	$ 37.90	$ 56.45	$ 73.90	$ 69.23	$ 52.17	$ 39.36	$ 42.06	$ 55.18	
(2) Fuel Clause Adjustment ($/kWh)		0.02805	0.02929	0.02717	0.02907	0.03359	0.03245	0.03090	0.02968	0.02828	0.02789	0.03099	0.03244	
FCA X kWh usage		$ 20.56	$ 18.51	$ 17.28	$ 16.21	$ 18.25	$ 22.32	$ 27.83	$ 25.04	$ 17.98	$ 15.74	$ 18.69	$ 24.21	
CIP surcharge ($/kWh)														
(2) Jan-Nov 2013	$ 0.001860	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0019	$ 0.0029	
(2) Dec 2013	$ 0.002935													
CIP surchrg. X customer's usage		$ 1.36	$ 1.18	$ 1.18	$ 1.04	$ 1.01	$ 1.28	$ 1.68	$ 1.57	$ 1.18	$ 1.05	$ 1.12	$ 2.19	
Total av. resid. monthly bill		$ 80.17	$ 70.86	$ 69.92	$ 63.26	$ 64.28	$ 87.17	$ 110.52	$ 102.94	$ 78.44	$ 63.26	$ 68.97	$ 89.58	$ 79.12
Av. Resid. energy charge + FCA ($/kWh)		9.78	9.90	9.69	9.88	10.33	11.45	11.30	11.17	11.03	9.76	10.07	10.64	10.42

(1) Source: Xcel Electric's 2013 Annual Jurisdictional Report, page E-29, May 01, 2014. (Docket 14-4)
(2) Source: Xcel Electric's response to IR 25 in Docket No. E999/AA-13-599.

Minnesota Power		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Monthly Av.
Av. residential monthly kWh usage		1,067	845	785	757	626	517	701	625	648	524	837	1025	746
(1) Number of customers		121,261	121,043	121,048	121,018	121,312	122,241	121,345	121,338	121,529	121,239	121,224	121,165	121,314
(1) Residential sales (MWh)		129,363	102,234	95,060	91,637	75,899	63,247	85,101	75,897	78,745	63,567	101,482	124,250	90,540.11
(2) Customer Charge		$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	
(2) Energy charge ($/kWh)			(a)		(b)		(c)		(d)		(e)			
		0-300 kWh	0.05098	301-500 kWh	0.06735	501-750kWh	0.08168	751-1000 kWh	0.08445	over 1000kWh	0.08937			
	(a)	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	
	(b)	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	$ 13.47	
	(c)	$ 20.42	$ 20.42	$ 20.42	$ 20.42	$ 10.26	$ 1.42	$ 16.44	$ 10.25	$ 12.08	$ 1.99	$ 20.42	$ 20.42	
	(d)	$ 21.11	$ 7.99	$ 2.98	$ 0.61							$ 7.36	$ 21.11	
	(e)	$ 5.97											$ 2.28	
Total monthly energy charge		$ 76.27	$ 57.17	$ 52.17	$ 49.79	$ 39.03	$ 30.18	$ 45.21	$ 39.01	$ 40.85	$ 30.75	$ 56.54	$ 72.57	
(2) Fuel Clause Adjustment ($/kWh)		0.01382	0.01281	0.01199	0.01101	0.00957	0.01104	0.01175	0.01053	0.01050	0.01134	0.01301	0.01291	
FCA X kWh usage		$ 14.74	$ 10.82	$ 9.42	$ 8.34	$ 5.99	$ 5.71	$ 8.24	$ 6.59	$ 6.80	$ 5.95	$ 10.89	$ 13.24	
(2) CIP surcharge	$ 0.001467													
CIP surcharge X customer's bill		$ 1.56	$ 1.24	$ 1.15	$ 1.11	$ 0.92	$ 0.76	$ 1.03	$ 0.92	$ 0.95	$ 0.77	$ 1.23	$ 1.50	
Total av. resid. monthly bill		$ 100.58	$ 77.23	$ 70.73	$ 67.24	$ 53.93	$ 44.66	$ 62.48	$ 54.52	$ 56.60	$ 45.46	$ 76.66	$ 95.31	$ 67.12
Av. Resid. energy charge + FCA ($/kWh)		8.53	8.05	7.84	7.68	7.19	6.94	7.62	7.29	7.35	7.00	8.06	8.37	7.66

(1) Source: MP's 2013 Annual Jurisdictional Report, page E-29 extra, April 30, 2014.
(2) Source: MP's response to IR 25 in Docket No. E999/AA-13-599.

Minnesota Electric Utilities' Average Residential Bills for 2013

Otter Tail Power	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Monthly Av.
Av. residential monthly kWh usage	1,469	1,505	1,222	1,164	913	700	825	779	833	685	963	1,299	1,027
(1) Number of customers	47,200	47,052	47,166	47,125	47,249	48,358	48,557	48,530	48,569	48,038	47,236	47,303	47,699
(1) Residential Sales (MWh)	69,340	70,814	57,629	54,847	43,144	33,869	40,053	37,791	40,457	32,918	45,470	61,443	48,981
(2) Customer Charge	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	
(2) Energy charge ($/kWh)	0.08192	0.08192	0.08192	0.08192	0.08192	0.07976	0.07976	0.07976	0.07976	0.08192	0.08192	0.08192	
Total monthly energy charge	$ 120.35	$ 123.29	$ 100.09	$ 95.34	$ 74.80	$ 55.86	$ 65.79	$ 62.11	$ 66.44	$ 56.14	$ 78.86	$ 106.41	
(2) Fuel Clause Adjustment ($/kWh)	0.00078	0.00330	0.00484	0.00210	0.00108	(0.00180)	(0.00148)	0.00110	(0.00003)	(0.00004)	(0.00223)	(0.00247)	
FCA X kWh	$ 1.15	$ 4.97	$ 5.91	$ 2.44	$ 0.99	$ (1.26)	$ (1.22)	$ 0.86	$ (0.02)	$ (0.03)	$ (2.15)	$ (3.21)	
(2) CIP surcharge	0.00142	0.00142	0.00142	0.00142	0.00142	0.00142	0.00142	0.00142	0.00142	0.00142	0.00175	0.00175	
CIP surchrg. X customer's bill	$ 2.09	$ 2.14	$ 1.74	$ 1.65	$ 1.30	$ 0.99	$ 1.17	$ 1.11	$ 1.18	$ 0.97	$ 1.68	$ 2.27	
Total av. resid. monthly bill	$ 132.08	$ 138.89	$ 116.24	$ 107.94	$ 85.59	$ 64.10	$ 74.24	$ 72.57	$ 76.10	$ 65.58	$ 86.90	$ 113.97	$ 94.52
Av. Resid. energy charge + FCA ($/kWh)	8.27	8.52	8.68	8.40	8.30	7.80	7.83	8.09	7.97	8.19	7.97	7.95	8.16

(1) Source: OTP's 2013 Annual Jurisdictional Report, page E-29, April 30, 2014.
(2) Source: OTP's response to IR 154 in Docket No. E999/AA-11-792.

Alliant	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Monthly Av.
Av. residential monthly kWh usage	921	821	760	657	611	598	822	740	877	616	639	869	744
(1) Number of customers	32,787	32,778	*32,780*	32,779	32,756	32,744	32,721	32,715	32,726	32,727	32,747	32,779	393,039
(1) Residential Sales (MWh)	30,192	26,902	24,903	21,540	20,003	19,581	26,899	24,216	28,702	20,157	20,937	28,476	292,507
(2) Customer Charge	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	
(2) Energy charge ($/kWh)	0.11258	0.11258	0.11258	0.11258	0.11258	$ 0.11258	$ 0.11258	$ 0.11258	$ 0.11258	0.11258	0.11258	0.11258	
En. Chrg. X kWh usage	$ 103.67	$ 92.40	$ 85.53	$ 73.98	$ 68.75	$ 67.32	$ 92.55	$ 83.33	$ 98.74	$ 69.34	$ 71.98	$ 97.80	
(2) Fuel Clause Adjustment ($/kWh)	(0.0006)	(0.0043)	(0.0073)	(0.0079)	(0.0087)	(0.0075)	(0.0067)	(0.0056)	(0.0050)	(0.0037)	(0.0048)	(0.0048)	
FCA X kWh	$ (0.57)	$ (3.51)	$ (5.53)	$ (5.16)	$ (5.29)	$ (4.50)	$ (5.47)	$ (4.17)	$ (4.35)	$ (2.30)	$ (3.08)	$ (4.20)	
(2) CIP surcharge ($/kWh)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	(0.00236)	0.00022	0.00022	
CIP surchrg. X kWh	$ (2.17)	$ (1.94)	$ (1.79)	$ (1.55)	$ (1.44)	$ (1.41)	$ (1.94)	$ (1.75)	$ (2.07)	$ (1.45)	$ 0.14	$ 0.19	
Total av. resid. monthly bill	$ 109.42	$ 95.45	$ 86.70	$ 75.77	$ 70.51	$ 69.91	$ 93.63	$ 85.91	$ 100.82	$ 74.09	$ 77.54	$ 102.30	$ 86.84
Av. Resid. energy charge + FCA ($/kWh)	11.20	10.83	10.53	10.47	10.39	10.51	10.59	10.69	10.76	10.89	10.78	10.78	10.70

(1) Source: IPL's response to IR 25 in Docket No. E999/AA-13-599.
(2) Source: IPL's response to IR 25 in Docket No. E999/AA-13-599.

Dakota Electric Association	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013 Monthly Av.
(1) Av. residential monthly kWh usage	733	632	636	558	543	688	901	844	636	564	603	746	674
(2) Customer Charge	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	
(2) Energy Charge ($/kWh)	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.11544	$ 0.11544	$ 0.11544	$ 0.10144	$ 0.10144	$ 0.10144	$ 0.10144	
En. Chrg. X kWh usage	$ 74.37	$ 64.09	$ 64.51	$ 56.58	$ 55.13	$ 79.42	$ 103.97	$ 97.39	$ 64.49	$ 57.24	$ 61.16	$ 75.71	
(2) Power Cost Adjustment	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	0.0110	
Power Cost Adj. X kWh	$ 8.06	$ 6.95	$ 6.99	$ 6.14	$ 5.98	$ 7.57	$ 9.91	$ 9.28	$ 6.99	$ 6.21	$ 6.63	$ 8.21	
(2) DSM surcharge ($/kWh)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	
DSM surchrg. X customer's bill	$ 0.51	$ 0.44	$ 0.45	$ 0.39	$ 0.38	$ 0.48	$ 0.63	$ 0.59	$ 0.45	$ 0.39	$ 0.42	$ 0.52	
Total av. resid. monthly bill	$ 90.95	$ 79.48	$ 79.95	$ 71.10	$ 69.48	$ 95.47	$ 122.50	$ 115.26	$ 79.93	$ 71.84	$ 76.22	$ 92.44	$ 87.05
Av. Resid. energy charge + FCA ($/kWh)	11.24	11.24	11.24	11.24	11.24	12.64	12.64	12.64	11.24	11.24	11.24	11.24	11.59

(1) Source: Xcel's average residential kWh usage figures were used as a proxy, because Dakota does not file a detailed MN Annual Jurisdictional Report.
(2) Source: Dakota's response to IR 25 in Docket No. E999/AA-13-599.

Attachment E16

Background Information on Fuel Clause Issues from Recent Dockets

The following is a synopsis of discussions about financial accountability for replacement power costs during forced outages. Following the Department's review of the IOUs' November 10, 2014 reply comments in 13-599 regarding sharing the lessons learned and contractors accountability, the Department recommended that, at least until the FCA incentive is changed, the Commission require the following for IOUs:[1]

1) Utilities seeking to recovery 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.
2) IOUs must 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.
3) Utilities should adopt Xcel's program, identified in more detail in Attachment D of its November 10 comments, to hold contractors more accountable for replacement power costs, to the extent those practices are not already in place.
4) 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.

The Department clarifies here that it is still recommending the use of a mechanism designed to ensure that energy costs are internalized by IOUs in the same manner that IOUs internalize capital costs (between rate cases).[2]

As discussed further in the Department's December 31, 2014 response comments in 13-599,

> 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.

[1] Section II.A of the Department's December 31, 2014 response comments in Docket No. E999/AA-13-599.
[2] See Section III, FCA Mechanism, pages 8-16 of the Department's December 31, 2014 response comments in Docket No. E999/AA-12-757, available at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={1BCA9F40-4ACC-43E8-A01F-71BDF6BED367}&documentTitle=201412-105847-01

> 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.

The Department's lessons learned recommendations were only designed to alleviate in part the regulatory issues identified by the Department during its forced outages investigation in Docket No. E999/AA-11-797 regarding the current regulatory framework as it applies to the recovery of energy costs, including but not limited to:

(1) The IOUs have the specific knowledge of their operations, not the Department or the Commission.

(2) Not all IOUs have in place a reliable <u>and</u> tractable database that fully uses the specific knowledge of their operations that they have or should have for the purpose of decision management and control. The Department notes in particular that: (a) several round of discovery were needed to understand the basic reasons for certain forced outages that occurred during FYE11, and (b) a utility stated that "[d]uring this period [FYE11], there were no delays or lack of performance by contractors affecting outages."[3] However, it became clear after extensive discovery by the Department that this utility should have at least noted the incompatible o-ring error or the assembly error in response to the Department's discovery.[4]

(3) Not all IOUs have in place a reasonable Quality Management program with contractors. The Department notes for example that a contractor was left without oversight during a critical phase involving the use of replacement parts that needed to be made of a specific material.[5]

(4) Certain IOUs appear to still argue that "it is completely inappropriate for the Department to unilaterally apply an invented standard after-the-fact,"[6] even though the Department's analysis and discovery regarding the FYE11 forced outages was only based on the premise that the prudency of these costs is associated with the IOUs' ability to : (1) learn from past "failures," e.g., have in

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[3] See background information at page 11 of the Department's December 31, 2014 Response Comments in Docket No. E999/AA-12-757, available at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={1BCA9F40-4ACC-43E8-A01F-71BDF6BED367}&documentTitle=201412-105847-01

[4] See the Department's complete review of these contractors' errors at pp. 38-46 and pp. 58-61 of the Department's December 12, 2012 response comments in Docket No. E999/AA-11-792, available at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={29D584DF-51F7-4DC3-A2D2-38777542C303}&documentTitle=201212-81728-01

[5] Id.

[6] Source: page 2 of MP's November 9, 2012 reply comments in Docket No. E999/AA-11-792. See also page 10 of 11 of MP's February 11, 2015 reply comments in Docket No. E999/AA-12-757.

> place a system that keeps a meaningful and tractable record of: (a) past forced outages, (b) the source of these outages (incidents), and (c) the steps taken to prevent and/or alleviate a reoccurrence of these incidents; and (2) justify the specific preventive steps taken, even if no steps were taken, based on a reasonable ex-ante analysis that identifies all reasonable options available, including industry-available best practices.[7]

The Department's review of the IOUs' February 11, 2015 response to the first two recommendations, forced outages information and searchable database, indicates that the IOUs believe that they are already fully using all relevant available information through general and specific forums. IPL did state that it "would contribute information to the extent required and without risking confidentiality," "if such a database were to be made available through a broader effort among Minnesota IOUs."

The Department notes that, until the FCA incentive is changed, the first two recommendations, forced outages information in the AAA filings and searchable database, are designed to: (a) encourage the IOUs to fully use the specific knowledge of their operations as if they were competitive firms, and (b) provide the Commission with the relevant information it needs to assess the prudency of the IOUs' actions as discussed above.

The Department still believes that, at least until the FCA incentive is changed, the reasonableness of charging ratepayers for replacement power costs during any forced outage should be associated with the IOU's ability to learn from past outages as well as to justify the specific preventive steps taken as discussed above.

However, the Department is also looking forward to the Commission's input regarding the additional information and/or data that would allow the Commission to make determinations regarding the reasonableness of costs charged to ratepayers through the FCA rate rider.

The Department's review of the IOUs' February 11, 2015 response to the last two recommendations in Docket No. E999/AA-13-599, holding contractors more accountable for replacement energy costs, indicates that the IOUs believe that they already have reasonable processes in place or designed to achieve results similar to Xcel's quality management plan. The IOUs appear also to agree that the addition of language to the "Supplier Warranties" section of the contracts to indicate that contractors may be liable for a limited amount of replacement power costs could, as IPL put it, "dissuade reputable contractors from bidding on the project." OTP added that:

> 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.

[7] Source: pp. 1-2 of the Department's July 11, 2012 Supplemental Comments in Docket No. E999/AA-11-792.

The Department's rationale for recommending that "the Commission require Xcel and other utilities add language to the 'Supplier Warranties' section of the contracts to indicate that contractors may be liable for a limited amount of replacement power costs, such as a stated dollar amount per day," was to ensure that contractors have "skin in the game":

> 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.[8]

The Department or the Commission cannot and should not be in the business of micro-managing the IOUs. As a result, the Department was not and is not recommending any specific amount or formula to ensure that contractors have a skin in the game. It is the IOUs' responsibility to ensure that the contractors they chose are held accountable for their errors, taking into account their specific knowledge of their operations. For example, IPL stated that "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."

Finally, the Department notes that MP stated that its "standard language is quite inclusive and would include a claim for replacement power costs." As discussed further below, this statement raises another regulatory issue. Even if a utility has reasonable processes in place, ratepayers may still be at risk if the IOU does not implement its own processes, including but not limited to not actively pursuing recovery from the contractor responsible for replacement energy costs.

As shown in the Department's December 12, 2012 response comments in 11-792, reproduced in relevant part below, MP stated the following in response to follow-up discovery regarding a forced outage resulting from a contractor's use of incompatible material that:[9]

> - *Did MP have any performance provision in the contract with the errant vendor to protect its shareholders and its ratepayers from any additional costs in case the vendor fails to perform?*
> - *If so, what was the provision and how did MP pursue that provision? Were any amounts recovered by MP?*

[8] Source: page 8 of the Department's December 31, 2014 response comments in 13-599.

[9] Source: Department's December 12, 2012 response comments at 44 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

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

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

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

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

MP's response raises at least two questions. First, assuming that MP used its "standard contract language," MP does not appear to have actively pursued recovery from the contractors' errors identified in the Department's December 12, 2012 response comments in Docket No. E999/AA-11-792. Second, if MP did not use its "standard contract language," MP did not justify why it did not use the language that it now says would have allowed the Company to actively pursue recovery from the contractors.

Utilities are typically highly focused when pursuing cost recovery on behalf of shareholders. The discussion summarized above indicates a relative lack of willingness of utilities to pursue cost recovery on behalf of ratepayers, and highlights the need for a new mechanism to ensure that energy costs are internalized by IOUs in the same manner that IOUs internalize capital costs (between rate cases). Currently, only the level of capital cost recovery is fixed between rate cases, providing a clear incentive to reduce these costs between rate cases.

Until such a mechanism is approved by the Commission in Docket E999/AA-12-757 and implemented by the IOUs, the Department's recommendations in Docket E999/AA-13-599 or other information required by the Commission to show that utilities' FCA rates are reasonable should help provide detail sufficient for the Commission to determine the reasonableness of the utilities' rates.

The Department is looking forward to the Commission's input regarding the information and/or data that would allow the Commission to make a determination of reasonableness of FCA rates.