MINNESOTA DEPARTMENT OF COMMERCE

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June 15, 2016 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Review of the 2014-2015 Annual Automatic Adjustment Reports (Report-Part 1)**
Docket No. E999/AA-15-611

Dear Mr. Wolf:

Minnesota Rules 7825.2800 through 7825.2830 requires natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports. To provide further context to these reports, the Department provides excerpts from the Statement of Need and Reasonableness (SONAR) that the Commission issued when it adopted these rules.

These rules were put in place in 1984 in Docket No. G,E-999/R-83-467. In its April 18, 1984 SONAR (1984 SONAR) at pages 10-11, the Minnesota Public Utilities Commission stated the following regarding the purpose of the annual filings by the utilities:

> There currently is no provision in the rules to require the [C]ommission to annually review the entire effect of automatic adjustments upon customer rates, consumption patterns, utility revenues and distribution of supplier refunds; nor is there any provision to review projected fuel and gas costs. Therefore, the intent of the proposed additions is to make information about automatic adjustment of charges available for annual review by the commission, intervenors and the public, to provide a means by which the [C]ommission may determine the appropriateness and reasonableness of the separate charge and refund transactions during a prior year.
>
> Currently utilities submit periodic automatic adjustment reports to the Minnesota Department of Public Service (DPS) [a predecessor to the Department of Commerce]. These reports are reviewed by the DPS to determine that the rates are in compliance with [C]ommission rules and approved rates. An annual report filed directly with the Commission will enable the

> Commission to more effectively discharge its duties to review and monitor rates pursuant to Minn. Stat. § Ch. 216B (1982).
>
> The materials required to be submitted will allow the Commission to make an independent, accurate evaluation of the automatic adjustment charges for each utility.
>
> The information required by the Commission for the annual report of automatic adjustment of charges is needed to fully evaluate the impact these charges have had upon the ratepayers of each utility during the reporting period.

The Commission stated the following on page 13 regarding how the information in the reports is to be used at the Commission's annual meeting ("The commission shall annually conduct a separate meeting to review the automatic adjustment of charges reported herein"):

> This addition to the rule will allow the Commission an opportunity to review and evaluate all utilities' automatic adjustments at one time, giving the Commission a broad perspective for its analysis of the application and impact of automatic adjustments. This meeting will also give the Commission an opportunity to review any cost changes in gas or electric utility fuel purchases and will allow the public and utilities to address to [sic] the appropriateness of changes in automatic adjustments during the reporting period.

Attached is the first part of the Minnesota Department of Commerce, Division of Energy Resource's (Department or DOC) *Review of the 2014-2015 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE15 AAA) of the information provided by the utilities, to assist the Commission in its annual review of rates charged by electric utilities for the period of July 1, 2014 through June 30, 2015. Each electric utility discussed in this report (Report-Part 1) is being sent a public version. A trade secret version specific to each utility is being sent via electronic mail to the respective utilities.

In this review, the Department examined the reports of the Resident Inspectors of the Nuclear Regulatory Commission (NRC) regarding forced outages of Minnesota's nuclear power plants during this regulatory period of July 1, 2014 through June 30, 2015. When forced outages resulted from a failure to comply with the NRC's Code of Federal Regulations Title 10, the Department relied on reports from Northern States Power Company, d/b/a Xcel Energy (Xcel) to recommend disallowance of incremental costs of the forced outages.

In addition to this review, the Department will file the second part of our report, Report-Part 2 consisting of a review of rates charged pursuant to the Minnesota Independent System Operator (MISO) "Day 2" Energy Market and Ancillary Services Market. The Department expects to file this review by August 15, 2016.

The Department is available to answer any questions the Minnesota Public Utilities Commission (Commission) may have regarding this summary of the FYE15 electric AAA report herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/lt
Attachments

# Review Of 2014-2015 (FYE15)
# Annual Automatic Adjustment Reports

## For Electric Utilities

## Submitted To The
## Minnesota Public Utilities Commission

Docket No. E999/AA-15-611

June 15, 2016

**PUBLIC DOCUMENT**

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## I. OVERVIEW

This document provides the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) summary and partial review of the automatic adjustment charges for the July 2014 - June 2015 (FYE15) reporting period, which were filed by five Minnesota electric utilities in compliance with Minnesota Rule 7825.2810.

The Department anticipates filing by August 15, 2016 a review of the portion of fuel clause adjustment rates that recover costs of the Minnesota Independent System Operator's (MISO) Day 2 Market and Ancillary Services Market issues.

The Department offers recommendations to the Minnesota Public Utilities Commission (Commission), but overall recommends that the Commission review this information and determine whether the rates charged by electric utilities during this period were reasonable.

The utilities included in this report are:

- Dakota Electric Association (Dakota or DEA);
- Interstate Power Company – Electric Utility (IPL or Interstate Electric);[1]
- 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.[2]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2014 to June 30, 2015, accurately adjusted their energy rates to reflect changes in fuel costs according to Commission rules and variances. In addition, the Department examined the reports of the Resident Inspectors of the Nuclear Regulatory Commission (NRC) regarding forced outages of Minnesota's nuclear power plants during this regulatory period of July 1, 2014 through June 30, 2015. When forced outages resulted from a failure to comply with the NRC's Code of Federal Regulations Title 10, the Department relied on reports from Northern States Power Company, d/b/a Xcel Energy (Xcel) to recommend disallowance of incremental costs of the forced outages.

The FYE15 reporting period marks the tenth full year of operation under the MISO Day 2 Market, which began operations on April 1, 2005.

[1] Since IPL sold its distribution facilities to an electric cooperative at the end of July 2015, the next AAA period will be the last time that IPL will file these reports.
[2] 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.

## 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;
- 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.[3]

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.[4]

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.

In its 1984 SONAR, the Commission stated the following at page 12 regarding the purpose of this requirement:

> This addition to existing rules is necessary and reasonable because the existing rules provide that certain accounts included in the uniform system of accounts will be used in the calculation of automatic adjustments. An independent auditor's report will provide, in addition to the checks on the computation of automatic adjustment charges done by the DPS and the Commission, a further check that the charges and

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

[4] 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.

credits used in the computation are in compliance with the uniform system of accounts as required by these rules.

All electric utilities submitted auditors' reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes the following.

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

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

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

Third, MP's auditor noted several exceptions where the difference between the "average monthly cost of fuel consumed per ton" and the "average monthly cost of fuel purchased by ton" was greater than 5 percent. MP's auditors stated that MP's management indicated that the differences were due either to "inventory quantity adjustments following physical inventory accounts" or to "recent declines in the cost of inventory purchases" for the tested months of October 2014 and April 2015.[5] The Department recommends that MP provide a narrative in reply comments explaining and discussing this issue with enough detail to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs that were charged to MP's ratepayers.

[5] Source: page 16 of 192 of MP's FYE15 report in Docket No. E999/AA-15-611.

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.

*B. SUMMARY OF FUEL COST PROJECTIONS*

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. In its 1984 SONAR, the Commission stated the following at page 12 regarding the purpose of this requirement:

> The overall purpose of a five-year projection of fuel and gas costs is to aid the Commission in anticipating potential rate impacts upon Minnesota ratepayers. These projections will provide the Commission with a state-wide perspective on future energy requirements and costs which may affect customer consumption, the level of rates, facility expansion requirements, and rate design proposals.

The following summarizes the information provided by the utilities.

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.

The utilities' energy cost projections are summarized below.[6] The Department requests that OTP reconcile in reply comments the differences in forecasts for 2016 that are shown in: a) Part E, Section 10, Attachment H, pages 1-6 and b) Part G of OTP's filing.

**Table 1: Utility Projections of Total Energy Costs[7]**

**[TRADE SECRET DATA HAS BEEN EXCISED]**

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

[7] Includes costs recovered in utilities' base rates and FCAs.

Chart 1: Utility Forecasts of Annual Energy Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 2: Annual Percentage Changes in Utility Projections of Energy Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

During the Commission's deliberation in Docket Nos. E999/AA-12-757, 13-599 and 14-579, the Commission indicated an interest in understanding the reliability of the investor-owned utilities' (IOUs') annual energy forecasts (as provided in their AAA reports). The Department provides below for informational purposes Table 3 and Chart 2, which compare IOUs' forecasts of 2015 costs as provided in the IOUs' FYE10-FYE14 AAA reports to actual 2015 annual energy costs.[8] The data in Table 3 and Chart 2 are identified as trade-secret; however, since the information is now historical, the Department requests that utilities confirm in their reply comments that the information in Table 3 and Chart 2 below is now public rather than trade secret.

[8] IPL, OTP and Xcel's FYE10-FYE14 forecasts are calendar year forecasts, while MP's forecast is a fiscal year forecast.

Table 3: Utility Cost Projections vs Actual Costs

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department observes the following. First, IPL's estimated 2015 annual energy costs diverged increasingly *away from* actual 2015 annual energy costs, the closer IPL's forecasts were to 2015. By contrast, forecasts of MP, OTP and Xcel generally became closer to 2015's actual annual costs, the closer were the forecasts of these utilities to 2015.

Chart 2: Utility Forecasts of 2015 Costs Compared to Actual 2015

[TRADE SECRET DATA HAS BEEN EXCISED]

In addition, the Department notes that IPL, MP and Xcel appear to have systematically overestimated their 2015 energy costs by at least 4.9 percent and up to 46.2 percent for IPL, 4.2 percent and up to 18.6 percent for MP, and 13.3 percent and up to 26.6 percent for Xcel.[9] The Department notes that both MP and Xcel provide estimated FCA rates to their large power customers. By contrast, for 2015 OTP had a more reliable forecast than the other three IOUs since its 2015 forecast varied from 2015 actual annual energy costs by between -5.1 percent and 1.4 percent in its last three AAA reports.

[9] Source: Attachment E1.

The Department notes that IPL's actual FYE15 data was compared with IPL's FYE10-FYE14 forecasts for calendar year 2015 since IPL was not a Minnesota regulated IOU after July 2015.

## III. COMPLIANCES

The Department addresses the following reports in this section.[10]

A. *In the Matter of a Request for Investigation of Northern States Power Company's Practices Regarding Energy Marketing and the Fuel Clause* in Docket No. E002/CI-00-415.

B. *In the Matter of a Request by Northern States Power Company, d/b/a Xcel Energy for Commission Approval of Gas Financial Instruments Natural Gas Financial Instruments for Wholesale Electric Transactions,* Docket No. E002/M-01-1953

C. Xcel's Wind Curtailment Report *In the Matter of Northern States Power Company d/b/a Xcel Energy's Annual Automatic Adjustment of Charges Reports for Its Electric and Gas Utility Operations and Purchased Gas Adjustment True-up Filing,* Docket No. E,G999/AA-04-1279, and *In the Matter of a Request by Northern States Power Company, d/b/a Xcel Energy for Approval of a Power Purchase Agreement with Navitas Energy, LLC,* Docket No. E002/M-02-51.

D. *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Utility Service in Minnesota,* FCA Settlement Agreement (Xcel Electric's compliance filing) in Docket No. E002/GR-05-1428.

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

F. Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs) (*In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Renewable Energy Purchase Agreement with KODA Energy, LLC* Docket Nos. E002/M-08-1098, *In the Matter of Xcel Energy's Petition for Approval of a Power Purchase Agreement with Diamond K Dairy, Inc.,* E002/M-10-486 and *In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities* E999/AA-10-884)

G. Maintenance Expenses of Generation Plants (*In the Matter of the Review of the 2005 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities,* Docket No. E999/AA-06-1208).

[10] The Department notes that the analysis of compliances related to the MISO Day 1 market is discussed in Section V of this report, *Effects of the MISO Day 1 Market on Minnesota Ratepayers.* Discussion of the effects of the MISO Day 2 market will be in the August 2016 supplement to this report, *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

H. Plant Outages Contingency Plans (*In the Matter of the Review of the 2008 Annual Automatic Adjustment Reports for All Electric Utilities,* Docket No. E999/AA-08-995).

I. Sharing Lessons Learned Regarding Forced Outages (*In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities,* Docket No. E999/AA-10-884).

J. *In the Matter of Otter Tail Power Company's Petition for Approval of a Monthly Fuel Clause Adjustment True-Up Provision:* OTP's FCA True Up (E017/M-03-30).

K. *In the Matter of Xcel Energy's Petition for Approval of Replacement Power Purchase Agreement with WM Renewable Energy. LLC,* Xcel's Curtailment of WM Renewable Energy (Docket No. E002/M-10-161).

L. *In the Matter of a Petition by Minnesota Power for Approval of a Power Purchase Agreement with Manitoba Hydro,* Report on Purchased Power Agreement (PPA) with Manitoba Hydro (Docket No. E015/M-10-961).

The Department discusses each of these items below.

*A. IN THE MATTER OF A REQUEST FOR INVESTIGATION OF NORTHERN STATES POWER COMPANY'S PRACTICES REGARDING ENERGY MARKETING AND THE FUEL CLAUSE IN DOCKET NO. E002/CI-00-415*

On April 3, 2000, the Residential and Small Business Utilities Division of the Office of Attorney General (OAG) requested that the Commission initiate a summary investigation under Minn. Stat. §216B.21 into whether Xcel's cost allocations between retail ratepayers and wholesale electric sales was just and reasonable as to retail rates. On April 20, 2001, the OAG stated that a formal investigation was no longer warranted so long as Xcel complies with certain reporting requirements.

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 FYE15, the monthly generation costs allocated to retail and wholesale customers was provided for 2015.[11] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2015.

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

[11] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing of Docket No. E999/AA-15-611 on September 1, 2015, and was subsequently provided in full in a supplemental filing in the same Docket on September 30, 2015.

appears to comply with the requirements of the Commission's Order. Xcel's data indicated that for all three months in 2015, the retail average generation costs were less than the average generation costs allocated only to the wholesale sector.

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 2015 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 2015. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

*B. IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR COMMISSION APPROVAL OF GAS FINANCIAL INSTRUMENTS NATURAL GAS FINANCIAL INSTRUMENTS FOR WHOLESALE ELECTRIC TRANSACTIONS: XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/M-01-1953*

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 FYE15 AAA report also includes a copy of the prescribed letter by Xcel Electric to its external auditors.[12] The report included a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[13] 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, 2014 to June 30, 2015, as calculated in accordance with the criteria established by the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2700 to 7825.2820 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 concludes that Xcel Electric's Natural Gas Financial Instruments compliance filing complies with the Commission's Order in Docket No. E002/M-01-1953.

[12] See Part F, Section 1 of Xcel Electric's FYE15 AAA report.
[13] See Part F, Section 2 of Xcel Electric's FYE15 AAA report.

The Department intends to review Xcel Electric's continued compliance with this requirement in the FYE16 AAA report.

### *C. XCEL'S WIND CURTAILMENT REPORT IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORTS FOR ITS ELECTRIC AND GAS UTILITY OPERATIONS AND PURCHASED GAS ADJUSTMENT TRUE-UP FILING, DOCKET NO. E,G999/AA-04-1279, AND IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH NAVITAS ENERGY. LLC, DOCKET NO. E002/M-02-51.*

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 Agreements (PPAs). For example, in the Navitas Docket E002/M-02-51, the Commission required the following in Ordering Paragraph 1c:

> Xcel shall identify in its monthly fuel clause adjustment report the date, length, cost to ratepayers and reason for each Qualifying production Loss Event associated with the Navitas project and shall summarize all such events in its annual automatic adjustment (AAA) report.

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. There, in its April 4, 2006 Order, the Commission required in Ordering Paragraph 5 that "Xcel shall continue to track all curtailments and curtailment payments and report on them in its monthly and AAA filings."

In addition, Ordering Paragraph 7 of that Order required Xcel to "provide an annual assessment of wind commitments and available or planned transmission capacity" and to "include projected curtailment payments related to wind for a five-year time period in light of planned and existing projects and commitments to update the system."

For this report, the Department concludes that Xcel Electric is 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 FYE15 AAA filing a report on its projected wind curtailment payments over the 2015-2019 period for planned and existing projects and any commitments made to update the system.[14]

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 8.3 percent in FYE08, 2.4 percent in FYE09, and 1.8 percent in FYE13.[15] While curtailment costs increased substantially to 9.4 percent in

[14] Part H, Section 5, Schedule 2 of Xcel Electric's FYE15 AAA report.
[15] Source: Attachment E2.

FYE14, they were down again at 4.4 percent in FYE15.[16]

The Department notes that Xcel Electric's FYE15 wind curtailment report (Wind Report) indicates that, similar to Xcel's FYE14 Wind Report, all of the curtailment payments are related to MISO directives (curtailment reason code 3).

The FYE15 Wind Report states that the following three categories of events that were responsible for the FYE14 wind curtailments were also responsible for the FYE15 wind curtailments: [17]

1) Transmission Curtailment Events;

2) Dispatchable Intermittent Resource (DIR) Economic, Congestion and Negative Locational Marginal price (LMP) Related Curtailments (DIR Curtailment Events); and

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

The Department notes that the only outstanding issue related to Xcel's FYE14 wind curtailments was that "the cost reduction [due to Manual Curtailment Events] would have been larger if Xcel Electric curtailed only the facilities that do not receive Production Tax Credits."[18] As a result, the Department recommended that the Commission require Xcel Electric to discuss in a supplement of its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits, in response to Manual Curtailment Events.

Since Xcel indicated that, in response to Manual Curtailment Events, it only curtailed wind facilities that are not receiving Production Tax Credits, the Department will not pursue this issue further in this proceeding.[19]

The Department recommends that the Commission accept Xcel Electric's Wind Curtailment compliance filing in the FYE15 AAA docket.

*D. IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN MINNESOTA, 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

[16] Source: Attachment E2.
[17] Part H, Section 5, Schedule 2 of Xcel Electric's FYE15 AAA report.
[18] Department's August 26, 2015 response comments at 9-10 in Docket No. E999/AA-14-579.
[19] Source: Part H, Section 5, Schedule 2, Table 7 of Xcel Electric's FYE15 AAA report.

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 FYE15 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 FYE15 AAA filing. Xcel's filing provided a 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;[20]
- 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 are currently being requested to be collected through Xcel Electric's base rates in the current rate case Docket No. E002/GR-15-826. The Commission's October 5, 2015 Order in Docket No. E002/M-14-761 approved a 60-year decommission period and a $14.0 million annual decommission accrual starting January 1, 2016.

Based on our review of Xcel Electric's Schedule 1 for the FYE15 AAA, the Department concludes that there are no significant changes from Xcel's previous FYE14 AAA filing. The DOC notes that total permanent disposal costs paid to DOE were $451 million as of June

[20] 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.

30, 2015, with annual amounts for recent years between $7.3 and $12.3 million, and an average of $11.1 million over the past five fiscal years.[21]

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 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 2013 rate case, Docket No. E002/GR-13-868 or until such time as the Commission determined the appropriate use for those funds.[22]

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,[23] amounted 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 2013 Rate Case Docket No. E002/GR-13-868.[24] The sixth DOE refund was required by the Commission to be refunded to customers within 90 days of the Commission's June 3, 2016 Order in Docket No. E002/M-15-1089

The Department notes in the most recent Xcel decommissioning filing in Docket No.E002/D-14-761 the Commission approved a decommission accrual of $14,030,831 with an effective date of January 1, 2016.[25] Additionally, the Commission approved the Company's requested to eliminate the escrow account by transferring the balance into the qualified

[21] Part H Section 1, Schedule 1, Page 1. Xcel Energy's Annual Report, Docket No. E999/AA-15-611.
[22] December 18, 2013 Order in Docket No. E002/M-11-807
[23] Docket No. E002/D-14-761
[24] Source: Commission's May 8, 2015 Findings of Fact, Conclusions of Law and Order, at 52-53.
[25] Source: The Commission's October 5, 2015 Order in Docket No. E002/M-14-761.

decommissioning trust. The Commission required Xcel to file a compliance filing "to enable the Commission to determine the appropriate method for crediting any future Department of Energy Settlement proceeds resulting from the Settlement extension." In addition, the Commission required Xcel to provide additional information in its next triennial decommissioning filing.

Xcel filed its compliance filing on April 1, 2016; the Commission issued a notice that comments on that compliance filing are due July 15.

Regarding the AAA filing, 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. OFFSETTING REVENUES AND/OR COMPENSATION RECEIVED BY IOUS (IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S PETITION FOR APPROVAL OF A RENEWABLE ENERGY PURCHASE AGREEMENT WITH KODA ENERGY, LLC, DOCKET NO. E002/M-08-1098, IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH DIAMOND K DAIRY, INC., E002/M-10-486 AND IN THE MATTER OF THE REVIEW OF THE 2009-2010 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES 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."[26] 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."[27] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

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

[26] Source: Part H, Sections 1-9, page 5 of 6 of Xcel's FYE15 AAA report.
[27] Source: Part H, Sections 1-9, page 5 of 6 of Xcel's FYE15 AAA report.

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.

### *G. MAINTENANCE EXPENSES OF GENERATION PLANTS (IN THE MATTER OF THE REVIEW OF THE 2005 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES FOR ALL ELECTRIC AND GAS UTILITIES, 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.[28] 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 due to improvements in spending OTP, MP, and Xcel Electric are all spending more on operation and maintenance (O&M) costs than they are charging to their customers in rates.[29] 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 rate case, and this is the first time OTP has met or exceeded their budgeted maintenance costs since 2009. IPL's outage costs were much higher in FYE14, but dropped substantially in FYE15; however, IPL is no longer a rate-regulated utility in Minnesota. MP's outage costs were much higher in FYE15.

[28] Attachment E3 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, FYE14, and FYE15 for some utilities.
[29] Attachment E4 provides an annual breakdown of the IOUs' maintenance expenses of generation plants.

Table 4: Comparison of Generation O&M Costs

| | Test Year | Rate Case | Historical 2012-2014 Average | Difference from Rate Case |
|---|---|---|---|---|
| IPL | 2009 | $ 3,779,345 | $ 3,013,166 | $ (766,179) |
| MP | 2010 | $ 33,619,194 | $ 39,054,080 | $ 5,434,886 |
| Xcel Electric | 2014 | $ 193,685,565 | $193,411,860 | $ (273,705) |
| OTP | 2009 | $ 13,142,720 | $ 13,304,703 | $ 161,983 |

Due to the link between the level of O&M on facilities and forced outages of facilities, and due to different current ratemaking incentives (incentive to minimize O&M costs between rate cases with 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.

## *H. PLANT OUTAGES CONTINGENCY PLANS (IN THE MATTER OF THE REVIEW OF THE 2008 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES, DOCKET NO. E999/AA-08-995)*

In its March 15, 2010 Order, the Commission required the following in Ordering Paragraph 12:

> All electric utilities required to file annual automatic adjustment reports shall 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. The Commission asks the [Department] to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.

This requirement first stemmed from the drastic increase in OTP's energy costs due to replacement power costs in November ($39/MWh) and December 2007 ($51.20/MWh) caused by 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 state that "while we attempt to include contract terms or performance bonds to indemnify us for delays or lack of performance, requiring a contractor to indemnify us for replacement energy cost is cost prohibitive." (MP's September 29, 2009 reply comments at 9). However, utilities did not provide evidence to support that position, nor did they suggest other methods to protect ratepayers from paying for high replacement power costs during forced (unforeseen) outages.

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 any improvements made in lessons learned and "the reasonable contingency plans [developed by the utility] to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages."[30] Dakota Electric provided a general discussion about Great River Energy's goals. Otter Tail Power Company and Interstate Power Company did not address this requirement and thus did not comply with the Commission's Order noted above. MP stated only that "During this period, there were no delays or lack of performance by contractors identified which impacted the length of the outages and/or the replacement energy costs."[31]

Xcel Electric provided the following in its report:[32]

> Contractor and Supplier performance has improved over the last several 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.

[30] Order Point 12 of the Commission's March 15, 2019 Order in Docket No. E999/AA-08-995.
[31] Attachment 19, page 2 of 2, MP's FYE15 AAA report.
[32] Part K, Section 3 of Xcel Electric's FYE15 AAA report.

> In the event problems arise with services, equipment, and/or materials provided by the vendor/supplier, the remedy is found in the Terms and Conditions of the Purchase Order and/or contract. Remedies for problems that adversely affect generating plant performance (such as de-rates or unplanned outages) include the direct costs of re-work, including labor and/or materials, depending on the nature of the problem.
>
> The Company strives to always contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner. Therefore, we will continue to identify and work with these types of contractor issues on a going forward basis.

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.

Dakota Electric provided a simple overview in its report:[33]

> GRE's maintenance of generation assets is vital to ensure availability of the units when needed. GRE proactively works with contractors to achieve high performance contractor work during planned outages. GRE has multi-year contracts with major equipment manufacturers and outage support contractors (i.e. General Electric & Siemens) to help ensure that planned outages meet scope, budget and schedule goals. A number of these contracts have performance-based incentives for meeting outage schedules and budgets. Also, GRE has multiple outage planning staff and tools to help ensure that appropriate contingency plans are in place to mitigate the risk of delays or performance for contractors working on planned outage activities. GRE's proactive planning with all stakeholders helps ensure that planned outages are completed in a timely and fiscally responsible manner.

As the utilities generally have not advanced this discussion, the Department suggests an industry standard the Commission may wish to consider to ensure that the rates utilities charge to ratepayers through the permissive FCA are reasonable.

**Hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors**: The Nuclear Regulatory Commission holds utilities with licenses to operate nuclear generation facilities responsible for all events that occur at such facilities, whether due to work performed by a contractor or a direct employee of a utility. The Minnesota Commission may wish to use a similar standard regarding work done by contractors at non-nuclear facilities, including

[33] Exhibit A, page 7 of Dakota Electric Association's FYE15 AAA Report.

responsibility for incremental costs of replacement power due to forced outages caused by improper work on generation facilities. For example, since utilities have maintained that it is not feasible to hold contractors accountable for their work, utilities should not rely on contractors to supervise themselves; instead, utilities should supervise contractors directly. The Department discusses this issue further under the "Lessons Learned" section immediately below.

*I. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES (IN THE MATTER OF THE REVIEW OF THE 2009-2010 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES, 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 reporting requirement of Order Point 22 of the April 6, 2012 Order in Docket No. E999/AA-10-884.

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

For example, the Department notes that Xcel was able to return insurance proceeds to ratepayers due to reimbursement for Excess Fuel Oil during the startup of Sherco Unit 3. Xcel stated the following:[34]

> The March 2015 FERC Account 151 (fossil fuel) included a $503,486 settlement reimbursement from the insurance companies for the excess fuel oil that was consumed during the startup of Sherco Unit 3 following repairs. The Minnesota customers' share of this credit was about $364,429 based on March 2015 Minnesota jurisdictional MWh sales weighting relative to the NSP System total.

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

[34] Part E, Section 2, page 5 of 5, Xcel's FYE15 AAA report.

> In conventional and combined-cycle plants, boiler tube failures (BTFs) have been the main availability problem for as long as reliable statistics have been kept for each generating source. The three volumes of the Electric Power Research Institute (EPRI) report Boiler and Heat Recovery Steam Generator Tube Failures: Theory and Practice (1012757) present an in-depth discussion of the various BTF and degradation mechanisms, providing plant owners and operators with the technical basis to address tube failures and create permanent solutions. This field guide is based on the content of Boiler and Heat Recovery Steam Generator Tube Failures: Theory and Practice.
>
> **Results and Findings**
> Tube failures emanate from poor initial design, poor operation and maintenance, harsh fireside and cycle chemistry environments, and lack of management support for comprehensive reduction programs. A total of 35 tube failure mechanisms affecting conventional fossil plants are described in this field guide.

The EPRI Report, with which Minnesota utilities should be familiar, explained what must be clear to utilities about how to inspect boiler tubes to prevent failures and forced outages. Closely following this field guide may have reduced the amount of replacement power costs that have been charged to Minnesota ratepayers, for example, regarding the need to ensure that foreign material is excluded from generation facilities even when inspecting generation facilities:

> Foreign materials left in the boilers by careless inspectors have the potential to cause more damage faster than degradation itself. Be careful not to lose equipment that could plug or otherwise damage components. Also remember that finding and extracting dropped items can be costly and time-consuming.
>
> - Bring only the tools that are necessary into the immediate inspection area.
> - Secure loose items. Use lanyards when necessary.
> - Make sure equipment caps (*e.g.*, lens caps, battery covers) are secured.
> - Conduct pre- and post-inspection inventories of equipment.

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

Enforcement of this standard and the standard above of holding utilities accountable for contractor errors may be difficult to enforce. However, assuming that the FCA continues to function as it currently does, as a start the Commission may choose, for example, to require utilities to file the lengths (duration) and purposes of planned outages for the previous five years, along with the lengths and purposes for expected future outages for upcoming two years. Before being allowed recovery of the costs of any outages that are longer than expected, utilities at a minimum would need to explain sufficiently what caused the extensive delay and why it is reasonable to require ratepayers to pay for the incremental costs of replacement power. The Department expects to continue to monitor the IOUs' plant outages contingency plans in future AAA filings.

### *J. IN THE MATTER OF OTTER TAIL POWER COMPANY'S PETITION FOR APPROVAL OF A MONTHLY FUEL CLAUSE ADJUSTMENT TRUE-UP PROVISION: 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, 2015, Otter Tail submitted a compliance report and proposal to implement a true-up credit (decrease in rates) of $0.0006 per kWh. In Comments filed on August 31, 2015, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit. The Commission's October 6, 2015 Order approved Otter Tail's true-up decrease in rates beginning September 1, 2015.

### *K. IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF REPLACEMENT POWER PURCHASE AGREEMENT WITH WM RENEWABLE ENERGY. LLC, 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."[35] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

### *L. IN THE MATTER OF A PETITION BY MINNESOTA POWER FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH MANITOBA HYDRO, REPORT ON MP'S PPA WITH MANITOBA HYDRO (DOCKET NO. E015/M-10-961)*

The Commission's March 11, 2011 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.

MP provided the required reporting information in compliance with the Commission's Order in Docket No. E015/M-10-961.[36]

[35] Source: Part H, Sections 1-9, page 5 of 6 of Xcel Electric's FYE15 AAA report.

# IV. TOTAL FUEL COST REVIEW

## *A. OVERVIEW*

Table 5 summarizes the electric utilities' fuel cost recovery during FYE15.[37] 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. DEA and OTP's data was highlighted too because they both have an annual true-up to refund or recover previous over- and under-recoveries of their energy costs.[38]

**Table 5:**
**Summary of Automatic Fuel Adjustments FYE15**

| Utility | Fuel Cost Recovered ($) | Fuel Cost ($) | Over-Recovery/ (Under-Recovery) ($) | (%) |
|---|---|---|---|---|
| *DEA* | *$144,494,497* | *$141,789,483* | | |
| Interstate Electric | $17,958,409 | $16,982,336 | $976,073 | 5.75% |
| MP | $172,142,278 | $165,337,446 | $6,804,832 | 4.12% |
| *OTP* | *$58,154,238* | *$56,916,272* | | |
| *Xcel Electric* | *$816,139,541* | *$827,594,656* | | |

To review IPL's and MP's calculations of over and under-recovery of their energy costs, the Department compared actual costs of fuel purchased during the year to the fuel costs recovered through base rates and the monthly automatic adjustments.

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 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.[39] Generator outages and a variety of other supply-side factors can also cause variations in fuel costs.

[36] Source: Attachment No. 14 of MP's report in the FYE15 AAA.

[37] Supporting spreadsheets for FYE15 data with Department's calculations are provided in Attachment E5 (Dakota), Attachment E6 (IPL), Attachment E7 (MP), Attachment E8 (OTP) and Attachment E9 (Xcel Electric).

[38] The Department notes that DEA, OTP and Xcel Electric all have true-up mechanisms, so they are not financially impacted materially by any over/under recovery.

[39] 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.

*B. DAKOTA ELECTRIC ASSOCIATION*

Dakota serves about 103,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment E5 shows that DEA's resource adjustment includes $141,789,483 or $78.64/MWh in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[40] This amount is over 1 percent lower than the $149,582,605 or $79.55/MWh cost in FYE14.

DEA recovered $144,494,497 in fuel costs and thus over-recovered fuel costs in FYE15 by $2,705,014 or 1.91 percent.

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 FYE15 fuel costs were $20.09/MWh and $16,982,336 in total for its Minnesota operations in FYE15, a decrease of $2,930,230 compared to the $19,912,643 fuel costs in FYE14. On a per-MWh basis, fuel costs in FYE15 represent an 11 percent decrease over the $22.62/MWh experienced by IPL in FYE14.[41]

During FYE15, Interstate recovered $17,958,409 in fuel costs and experienced $16,982,336 in actual fuel costs for an over-recovery of 5.75 percent.[42] Interstate had 6 months in which over- and under-recoveries were in excess of 15 percent. For comparison, in FYE14 Interstate had 4 months of over- and under-recovery above 15 percent, with 7 months in FYE13 and 9 months in FYE12. In FYE15 Interstate experienced an over-recovery of 5.75 percent after experiencing 3.43 percent under-recovery in FYE14 and a 3.29 percent over-recovery in FYE13.

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[40] 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 power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).
[41] Source: Attachment E10.
[42] Source: Attachment E6.

*D. MINNESOTA POWER*

Minnesota Power serves about 144,000 electric customers in northeastern Minnesota. MP's fuel costs were $165,337,446 for FYE15.[43] As shown in Table 5 above, MP over-recovered its fuel costs by $6.8 million in FYE15, or approximately 4.12 percent of its actual costs. By comparison, in FYE14, MP's actual fuel costs in the FCA were $195,704,305 and MP under-recovered by approximately $2.3 million, or 1.16 percent. In FYE13, MP's actual fuel costs in the FCA were $186,736,616 and MP over-recovered by $606,145 or 0.32 percent. Compared to the $21.85/MWh level of fuel costs in FYE14, MP's costs in FYE15 of $19.12/MWh were 12 percent lower.[44]

The Department notes that MP's level of over/under-recovery varies from month to month. In FYE15, MP's monthly over/under-recoveries ranged from a $3 million over-recovery in December 2014, to a $0.8 million under-recovery in February 2015.

*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 were $56,916,272 or $24.56/MWh for OTP's Minnesota operations in FYE15.[45] This level is 0.2 percent lower than the $24.61/MWh cost in FYE14.[46]

During FYE15, Otter Tail experienced a 2.18% over recovery in FYE15 as a whole. As a result, OTP is providing an annual true up credit of $0.0006 per kWh to its Minnesota ratepayers starting on September 1, 2015.[47]

*F. XCEL ELECTRIC*

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had energy costs of $827,594,656 for FYE15, or $27.39/MWh. This level is 8.4 percent lower than the $29.91/MWh cost in FYE14.[48]

Xcel Electric is the only electric utility to use a forecasted FCA method.[49] 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

[43] Source: Attachment E7.
[44] Source: Attachment E10.
[45] Source: Attachment E8.
[46] Source: Attachment E10.
[47] Source: Commission's October 6, 2015 Order in Docket No. E017/M-03-30.
[48] Source: Attachment E10.
[49] See the Commission's May 4, 2012 Order in Docket No. E002/M-11-452.

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.[50]

Unlike other generation facilities in Minnesota, each of Xcel's nuclear power plants have two inspectors from the Nuclear Regulatory Commission (NRC), who work at the plant every day and are on call at all times. The NRC's focus is solely on safety, but the reports by the NRC Resident Inspectors provides useful information for the Commission to use in holding Xcel financially accountable for charging reasonable rates to its ratepayers.

The following uses information from the NRC's Reports on both Prairie Island (PI) and Monticello for the period of July 1, 2014 through June 30, 2015 in which there was a forced outage and in which Xcel did not comply with the requirements of the NRC's Code of Federal Regulations, which sets out "requirements binding on all persons and organizations who receive a license from NRC to use nuclear materials or operate nuclear facilities." Since forced outages in which Xcel complied with NRC's requirements are not discussed below, the Department notes that only the forced outages that occurred during this period at Prairie Island are discussed. In addition, the Department used information from Xcel's compliance filings from its 2005 rate case (Docket No. E002/GR-05-1428) in which Xcel identified costs of outages and estimated incremental costs of replacement power.

### Prairie Island Unit 1

Unit 1 was unexpectedly forced off-line several times and a total of 56 days for essentially the same issue. Unit 1 was forced off-line for 18 days in January and February, 2015 (January 26 to February 12), 34 days in April and May (April 7 to May 9) and 4 days in May and June, 2015 (May 31 to June 3). As discussed below in the NRC's May 6, 2015 Integrated Inspection Report on Prairie Island Units 1 and 2 (NRC's May 2015 PI Report) and August 5, 2015 Integrated Inspection Report on Prairie Island Units 1 and 2 (NRC's August 2015 PI Report), Xcel's actions did not comply with the requirements of the NRC. As a result, the Department recommends that the Commission require Xcel to refund most if not all of the incremental costs of replacement power for the 56-day period.

According to the data that Xcel provided in its April 2, 2015, July 2, 2015 and October 5, 2015 compliance filings in Docket No. E002/GR-05-1428 and marked as trade-secret, the incremental cost of replacement power for all of these related outages was **[TRADE SECRET DATA HAS BEEN EXCISED]**. The Department requests that Xcel indicate in its reply comments whether, and if so why, the data indicated above continues to be trade secret at this time.

The NRC's May 2015 PI Report provided the following overview on page 5:

> Unit 1 began the inspection period [January 1, 2015 through March 31, 2015] operating at full power. On January 26, 2015, operations personnel shut down the Unit 1 reactor and entered a forced outage due to increased seal leakage from the 12

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[50] 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.

> reactor coolant pump (RCP) seal. The Unit 1 reactor achieved criticality on February 11, 2015, following the replacement of the 12 RCP seal and flushing of seal related piping. On February 12, 2015, the main generator was synchronized with the electrical grid. Operations personnel completed their power ascension activities and returned Unit 1 to full power operation on February 13, 2015.

In addition, the NRC's August 2015 PI Report noted on page 5 that the issue continued:

> Unit 1 began the inspection period operating at full power. On April 7, 2015, operations personnel shut down the Unit 1 reactor to replace the seal on the #12 reactor coolant pump. Unit 1 returned to power on May 9, 2015, following the seal replacement.

The NRC's May 2015 PI Report explained on page 15 how these outages were caused by Xcel's failure to follow NRC's requirements:

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

For further information on how Xcel's non-compliance with NRC requirements cause these outages at PI Unit 1, please see Attachment E11 to these comments.

## Prairie Island Unit 2

Unit 2 was unexpectedly forced off-line for 23 days in March, 2015 (March 5 to March 25 100 percent off-line; March 25 to March 28 ascending to full power). As discussed below, Xcel's actions did not comply with the requirements of the NRC's requirements. As a result, the Department recommends that the Commission require Xcel to refund the costs of replacement power for the 23-day period.

According to the data that Xcel provided in its July 2, 2015 compliance filing in Docket No. E002/GR-05-1428 and marked as trade-secret, the incremental cost of replacement power for the first 20 days of 100 percent outage was **[TRADE SECRET DATA HAS BEEN EXCISED]**. However, this figure does not include the costs of replacement power for the additional three days as Unit 2 ascended fully. Thus, the Department recommends that Xcel provide the costs of replacement power for the additional three days. In addition, the Department requests that Xcel indicate in its reply comments whether, and if so why, the data indicated above continues to be trade secret at this time.

The NRC's May, 2015 PI Report provided the following overview on page 5:

> Unit 2 began the inspection period operating at full power. On March 5, 2015, operations personnel shut down the Unit 2 reactor following a valve failure that resulted in a loss of instrument air to containment. Subsequent events resulted in the licensee declaring a Notice of Unusual Event at 4:06 am on March 5 (see Section 4OA3 for details). The licensee also conducted a forced maintenance outage to address the cause of the valve failure and to perform additional maintenance. The Unit 2 reactor achieved critically at 4:45 am on March 25, 2015. The Unit 2 generator was synchronized to the electrical grid at 2:55 pm that afternoon. Operations personnel completed their power ascension activities and returned Unit 2 to full power operation on March 28, 2015. Unit 2 operated at full power the remainder of the inspection period.

The NRC's May, 2015 PI Report provided more detailed information at pages 26-8:

> A self-revealing finding … was identified on March 5, 2015, for the failure to keep [environmentally qualified] EQ files current and the failure to replace or refurbish EQ electrical equipment at the end of its designated life. Specifically, the licensee had identified numerous EQ file errors in May 2014. These file errors resulted in the EQ designated life for multiple safety-related solenoid valves being non-conservative. Correction of the file errors should have resulted in the replacement of ten solenoid valves on a near-term basis. However, none of the solenoid valves has been replaced prior to the event on March 5, 2015.
> …
> The inspectors performed an additional review of [corrective action plan] CAP 1431268 and held discussions with engineering and work management personnel to determine what actions had been taken to correct the EQ files and replace the ten valves referred to in the CAP. The inspectors found that little to no action had been taken to correct either condition. Specifically, a work order was written to replace a different solenoid valve during the fall 2014 Unit 1 refueling outage; the inspectors found that this valve replacement had not occurred. In addition, no other work orders had been written for the remaining nine valves until March 6, 2015, due to the licensee's belief that the issues identified in CAP 1431268

> were programmatic in nature and had no impact on plant equipment. … The inspectors also found that the licensee had assigned an action to initiate a process to reconstitute the EQ files and other EQ program documentation. Although this action was originally scheduled for completion on June 23, 2014, it had been extended twice and was not yet complete. The failure to replace or refurbish the solenoid valves at the end of their designated life and to correct the EQ file deficiencies violated the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

The Department notes that the analysis conducted above was possible due to the NRC's Code of Federal Regulations and the oversight of Resident Inspectors at the nuclear power plants.

## V. 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.

### *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 2014 through June 2015:

**Table 6: MISO Schedule 10 Costs for July 2014 through June 2015**

| | Total Company | Estimated MN Jurisdiction |
|---|---|---|
| Xcel Electric | $10,395,183[51] | $7,705,866 |
| Interstate Power | $2,636,329[52] | $152,907 |
| Minnesota Power | $1,994,419[53] | $1,547,071 |
| Otter Tail Power | $809,139[54] | $387,490 |
| Total | $15,835,070 | $9,793,333[55] |

The total amount charged to these companies for MISO Schedule 10 costs increased by $1,555,749 or 7.87 percent from the previous reporting period. The total estimated Minnesota jurisdictional amount resulted in an increase of $652,804 or 7.14 percent increase from the previous reporting period. All IOU's MISO Schedule 10 costs increased from the previous reporting period. These utilities indicated that the increase is mainly attributable their proportionate shares of increases in MISO operating expenses and FERC operating expenses, which resulted in an increase in average MISO and FERC rates.

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 to continue to receive 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.

[51] MISO Schedule 10 costs paid by NSP-Xcel consist mostly of Minnesota costs, with some costs for Wisconsin, North Dakota and South Dakota. Minnesota jurisdiction percentage of 74.13% due to lower jurisdictional transmission and interchange allocations effective January 2015.

[52] MISO Schedule 10 costs paid by Alliant Energy for IPL for the AAA period. The Department assumed IPL's Minnesota retail jurisdictional percentage at 5.80%.

[53] MISO Schedule 10 costs paid by MP for the AAA period with an average Minnesota retail jurisdictional percentage of 77.57%.

[54] MISO Schedule 10 costs paid by OTP for the AAA period. The OTP estimated Minnesota retail jurisdictional percentage is 47.89%.

[55] Xcel AAA initial filing's Part 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.

MISO has deferred costs associated with the integration of the Entergy Operating Companies, Cleco Power LLC, South Mississippi Electric Power Association, Lafayette Utilities Systems and East Texas Electric Cooperative that will be recovered over a five year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

The Department included the actual MISO Schedule 10 costs paid by utilities for July 2014 to June 2015 in Table 6 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 2014 through June 2015.

*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 2014 through June 2015.

*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, 2014 to June 30, 2015, 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 7 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 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 occurred due to 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 and Day 3 Markets, which 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 further 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.

## VI. CHARTS FOR INFORMATIONAL PURPOSES

Attachment E12 shows various aspects of fuel charges and the effects on customers' bills.

### *1. Average Residential Bills for 2014*

The graph on page 1 of 4 of Attachment E12 illustrates the monthly average bills for residential customers in calendar year 2014. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges (as described on pp. 3-4 of Attachment E12). Overall, Interstate Electric had the highest average monthly residential bill of $105.25, followed by Otter Tail Power at $95.60, Dakota Electric at $85.99, Xcel Electric at $80.46 and Minnesota Power with the lowest average of $71.92 per month.

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

The graph on page 2 of 4 of Attachment E12 shows the amounts that residential customers paid during calendar year 2014 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 11.76¢/kWh, Xcel Electric with an average of 10.68¢/kWh, Interstate Electric 9.72¢/kWh, Otter Tail with an average of 8.30¢/kWh, and Minnesota Power 7.73¢/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.

## VII. RECOMMENDATIONS

For Section II, Filing Requirements, the Department recommends that MP provide a narrative in reply comments explaining and discussing the auditor's report exception related to MP's "average monthly cost of fuel consumed per ton by inventory location" for the months of October 2014 and April 2015, with enough details to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs (to be identified by MP).

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

For Section IV, Total Fuel Cost Review, the Department recommends that the Commission require Xcel to refund most if not all of the incremental costs of replacement power due to forced outages at Xcel's nuclear power plants that were caused by Xcel's non-compliance with the requirements of the NRC's Code of Federal Regulations.

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

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

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

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

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

# CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public Review of the 2014-2015 Annual Automatic Adjustment Reports
(Report-Part 1)

Docket No. E999/AA-15-611

Dated this 16th day of June 2016

/s/Sharon Ferguson

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