October 19, 2018 **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 2016-2017 Annual Automatic Adjustment Reports**
Docket No. E999/AA-17-492

Dear Mr. Wolf:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports. To provide further context to these reports, the Minnesota Department of Commerce, Division of Energy Resources (Department) provides excerpts from the Statement of Need and Reasonableness (SONAR) that the Minnesota Public Utilities Commission (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 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 [C]ommission, 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 of the SONAR 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 Department's *Review of the 2016-2017 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE17 AAA Report). Each electric utility discussed in this report is being sent a public version. A trade secret version specific to each utility is being sent via electronic mail to the respective utilities.

The Department is available should the Commission have any questions about the FYE17 AAA report herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL
Public Utilities Analyst Coordinator

NAC/ja
Attachments

PUBLIC REVIEW OF 2016-2017 (FYE17) ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

mn COMMERCE DEPARTMENT

DOCKET NO. E999/AA-17-492

OCTOBER 19, 2018

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I. OVERVIEW

This report summarizes the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) review of the automatic adjustment charges for the July 2016 - June 2017 (FYE17) reporting period, which were filed by four Minnesota electric utilities in compliance with Minnesota Rule 7825.2810.

The Department offers recommendations to the Minnesota Public Utilities Commission (Commission), and requests 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);
- 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 four rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2016 to June 30, 2017, accurately adjusted their energy rates to reflect changes in fuel costs according to Commission rules and Commission-approved rule variances.

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;

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

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

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

Further, Minnesota Rule 7825.2820 requires the following:

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

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 [a predecessor to the Department of Commerce] and the Commission, a further check that the charges and 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 Commission's July 21, 2017 Order in Docket No. E999/AA-15-611, regarding the review of the 2014-2015 Annual Automatic Adjustment Reports for all Electric Utilities, required the following in ordering paragraph 7:

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

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

7. In future AAA filings, Xcel, Minnesota Power, and Otter Tail must include in their independent auditors' reports the following:
   a. comparison of the documentation in support of payments and invoices received from energy suppliers;
   b. comparison of the base costs of power approved by the Commission to the bases used by the utility;
   c. recalculation of the billing adjustment charge (credit) per kWh charged to customers for purchased power for the entire applicable period by customer class;
   d. comparison of the accounting records for the revenues billed to customers for energy delivered for the relevant period to the total sales of electric energy;
   e. on a test basis, an examination of individual billings in each customer class by recalculating the automatic adjustment of charges and credits and tracing to individual customers' subsidiary records to ensure that the calculated credit or charge was correctly recorded;
   f. an examination of any corrections to FCA charges or other billing errors;
   g. a reconciliation of total revenue and cost of power in the utility's general ledger; and
   h. a recalculation of any true-up, and tracing of the related revenue and expense amounts to the utility's accounting records.

Based on our review, Xcel provided the above information in Part F of its Auditor's Report; however, MP and OTP did not address Commission's ordering paragraph 7. As a result, the Department recommends that MP and OTP address in their reply comments the compliance requirement of the above-quoted ordering paragraph 7 regarding additional requirements for the independent auditor's report.

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, and were excluded from Graph 1 below.

The utilities' energy cost projections are summarized below:[4]

Graph 1: Utilities Forecast of Annual Energy Costs ($/MWh)

[TRADE SECRET DATA HAS BEEN EXCISED]

Table 1.1: Utilities Forecast of Annual Energy Costs

($/MWh)	2018	2019	2020	2021	2022
	[TRADE SECRET DATA HAS BEEN EXCISED]				
(1) Dakota (FYE)					
(2) MP (FYE					
(3) OTP					
(4) Xcel Electric					

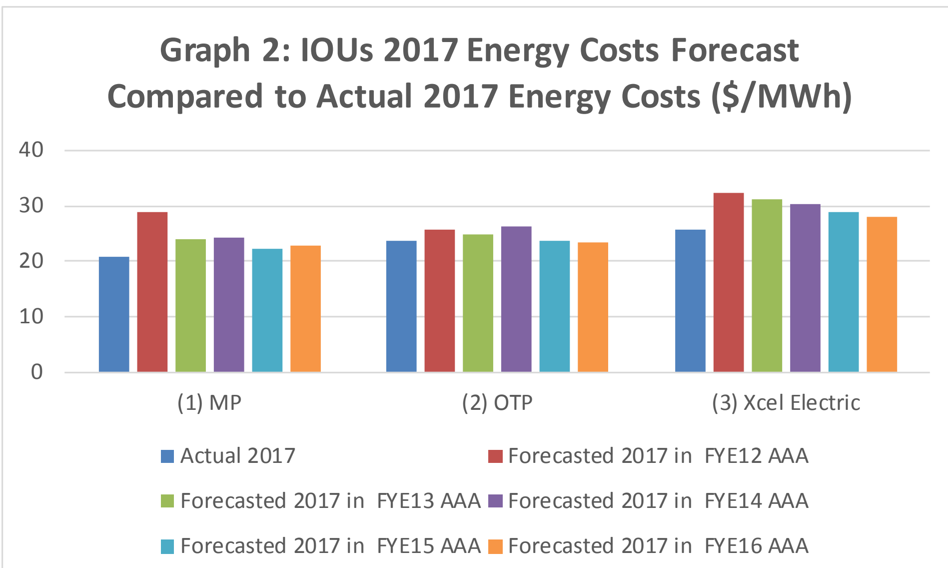
(1) Page 46 of 49, Dakota's August 31, 2017 AAA report in Docket No. E999/AA-17-492.
(2) Page 21 of 189, MP's August 31, 2017 AAA report in Docket No. E999/AA-17-492.
(3) Pages 158-162 of 235, OTP's September 1, 2017 AAA report in Docket No. E999/AA-17-492.
(4) Pages 68-72 of 369, Xcel's September 1, 2017 AAA report in Docket No. E999/AA-17-492.

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

Table 1.2 Annual and Cumulative Percent Change in Forecasted Energy Costs

	2018	2019	2020	2021	2022	2018-2022
	$/MWh					
Dakota		[TRADE SECRET DATA HAS BEEN EXCISED]				
MP						
OTP						
Xcel Electric						

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' annual energy cost forecasts (as provided in their AAA reports). The Department provides below for informational purposes Graph 2, Table 2.1 and Table 2.2, which compare the IOUs' forecasts of 2017 energy costs to actual 2017 energy costs.[5]



[5] OTP and Xcel Electric's FYE12-FYE16 forecasts for 2017 are calendar year forecasts, while MP's forecast for 2017 is a fiscal year forecast.

Table 2.1: IOUs 2017 Energy Cost Forecast Compared to Actual 2017 Energy Costs ($/MWh)

$/MWh	Actual 2017	Forecasted 2017 in FYE12 AAA	Forecasted 2017 in FYE13 AAA	Forecasted 2017 in FYE14 AAA	Forecasted 2017 in FYE15 AAA	Forecasted 2017 in FYE16 AAA
(1) MP	20.84	28.86	23.89	24.24	22.38	22.84
(2) OTP	23.78	25.67	24.97	26.39	23.67	23.32
(3) Xcel Electric	25.63	32.34	31.13	30.20	28.87	28.08

(1) Attachment 4, page 3 of 3, MP's FYE12-FYE16 AAA reports.
(2) OTP's FYE12-FYE16 AAA reports.
(3) Part G, Section 1, pages 1-5 of 5, Xcel Electric's FYE12-FYE16 AAA reports.

The Department notes that, while Xcel Electric and MP consistently over-forecasted energy costs by at least 7.3 percent, the forecasts generally became closer to 2017 actual annual costs, the closer to 2017 the forecasts were made. OTP had a more reliable forecast than the other two IOUs over the last five years, as shown in Table 2.2 below.

Table 2.2 Annual Percent Deviation from Actual 2017 Energy Costs

	Actual 2017 $/MWh	Forecasted 2017 in FYE12 AAA	Forecasted 2017 in FYE13 AAA	Forecasted 2017 in FYE14 AAA	Forecasted 2017 in FYE15 AAA	Forecasted 2017 in FYE16 AAA
MP	20.84	38.5%	14.64%	16.31%	7.39%	9.60%
OTP	23.78	8.0%	5.01%	10.98%	-0.46%	-1.93%
Xcel Electric	25.63	26.2%	21.46%	17.83%	12.64%	9.56%

III. COMPLIANCES

The Department addresses the following compliance reports required in the following proceedings.[6]

A. *In the Matter of a Request for Investigation of Northern States Power Company's Practices Regarding Energy Marketing and the Fuel Clause*, 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 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*

[6] The Department notes that the analysis of compliances related to the Midcontinent Independent System Operator (MISO) Day 1 market is discussed in Section V of this report, *Effects of the MISO Day 1 Market on Minnesota Ratepayers.* The discussion of the effects of the MISO Day 2 market is discussed in Section VI of this report, *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

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), Docket No. E002/GR-05-1428.

E. History of Nuclear Fuel Sinking Fund, 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 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.*, Docket No. 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).

H. Contingency Plans for Plant Outages (*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, Docket No. 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.

M. *In the Matter of Xcel Energy's Request for Approval of a Community Solar Garden Program*, Docket No. E002/M-13-867.

N. Transformer Reporting for Xcel, MP and OTP as required by the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, Ordering Point no. 23.

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, 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 allocation 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 AAA report on September 4, 2001 in Schedule 2 of Attachment G. Xcel Electric has since provided this data in each subsequent AAA report to date.

In its filing for FYE17, the monthly generation costs allocated to retail and wholesale customers was provided for 2017.[7] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2017.

The Department reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector, and noted that the information filed by the Company appears to comply with the requirements of the Commission's Order. Xcel's data indicated that in June, July, and August of 2017, the average generation costs allocated to retail customers 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 the lowest cost resources continue to be assigned to retail customers. Based on our review of the 2017 data, the Department recommends that the Commission accept Xcel Electric's compliance filing, including the high-level cost allocation test between wholesale and retail customers for June, July, and August of 2017. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings, as required by Docket No. E002/CI-00-415, Ordering Paragraph No. 2.

[7] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing in Docket No. E999/AA-17-492 on September 1, 2017, and was subsequently provided in full in a supplemental filing in the same Docket on October 13, 2017.

B. IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR COMMISSION APPROVAL OF NATURAL GAS FINANCIAL INSTRUMENTS FOR WHOLESALE ELECTRIC TRANSACTIONS: XCEL ELECTRIC'S COMPLIANCE FILING, 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. The Commission approved Xcel Electric's proposal 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 FYE17 AAA report includes a copy of the prescribed letter by Xcel Electric to its external auditors[8] and a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[9] which concluded:

> We have performed the procedures enumerated below, which were agreed to by Northern States Power Company, a Minnesota Corporation (the "Company") and the Minnesota Public Utilities Commission (the "Commission") (the specified parties), solely to assist you with the compliance of 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, as well as with Docket No. E002/M-01-1953….
>
> i. Through inspection of a sample of nine accounting records, we identified no exceptions with the accounting separation of retail and wholesale financial instruments.
>
> j. On a sample basis, we inspected vendor invoices and traced gains and losses to the accounting records for 2 selections. We did not identify any wholesale electric financial instrument gains or losses recorded in Account 555 or Account 804.

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[8] See Part F, Schedule 1 of Xcel Electric's FYE17 AAA report, as supplemented on October 9, 2018.

[9] See REVISED Part F, Schedule 2 of the Xcel Electric's FYE17 AAA report, as supplemented on October 9, 2018.

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. The Department intends to review Xcel Electric's continued compliance with this requirement in future AAA filings.

C. XCEL ELECTRIC'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 Purchased Power Agreements (PPAs). For example, in Docket No. 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 Electric'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 Electric 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 FYE17 AAA filing a report on its projected wind curtailment payments over the 2017-2021 period for planned and existing projects and any commitments made to update the system.[10]

[10] Part H, Section 5, Schedule 2 of Xcel Electric's FYE17 AAA report.

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. There have been two years in which wind curtailment costs were relatively high compared to the other post-FYE05 years, 8.3 percent in FYE08 and 9.4 percent in FYE14. In FYE17, wind curtailment costs as a percentage of wind costs were at their lowest level in the last seven years, 1.7 percent.[11]

The Department notes that Xcel Electric's FYE17 wind curtailment report indicates that, similar to previous wind reports, most of the curtailment payments are related to Midcontinent Independent System Operator (MISO) directives (curtailment reason code 3).[12]

The Department recommends that the Commission accept Xcel Electric's Wind Curtailment compliance filing provided in the Company's FYE17 AAA filing.

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

The Department notes that Xcel Electric's FYE17 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, DOCKET NO. E002/M-81-306

In the Commission's March 16, 2018 *Order Accepting Reports and Setting Additional Requirements* in Docket No. E999/AA-16-523, ordering paragraph 4 states:

[11] Source: Attachment 1 to this report.
[12] Part H, Section 5, Schedule 1 of Xcel Electric's FYE17 AAA report.

> The Commission hereby discontinues Xcel's Nuclear Fuel Sinking Fund reporting requirement established by Commission order dated July 14, 1981, in Docket No. E-002/M-81-306. The reporting requirement shall restart if Xcel becomes responsible for nuclear fuel interim storage and disposal expenses to the U.S. Department of Energy in the future.

Since the instant petition was filed on September 1, 2017, before the Commission's March 16, 2018 Order, Xcel continued to provide a schedule showing annual permanent disposal costs since 1981, which listed zero costs beginning in 2014. The Department expects Xcel to discontinue its Nuclear Fuel Sinking Fund reporting in future AAA filings in accordance with the Commission's March 16, 2018 Order.

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."[13] 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."[14] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

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[13] Source: Part H, Sections 1-10, page 4 of 6 of Xcel Electric's FYE17 AAA report.
[14] Source: Part H, Sections 1-10, page 5 of 6 of Xcel Electric's FYE17 AAA report.

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

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

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

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 in Docket No. E999/AA-06-1208 (the 06-1208 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.[15] When a plant experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those purchases flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates. The Commission agreed with the Department and the Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of schedule outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

As summarized below, Xcel, OTP, and MP are all spending less on maintenance of their generation facilities than was budgeted in their most recent rate cases. The Department also notes that, as shown in Attachment 2, outage costs have decreased as a share of net energy costs since FYE07 and FYE08.

[15] Attachment 2 shows that outage costs have decreased as a share of energy costs since FYE07.

Table 3
Comparison of Generation Maintenance Expense[16]
($ Millions)

	Test Year	Rate Case Budgeted	Actual 2016-2017 Average	Difference
Xcel	2016	184.7	174.2	-5.7%
OTP	2016	15.1	13.1	-13.5%
MP*	2017	42.5	38.6	-9.3%

*MP's average is limited to its 2017 actuals.

Due to the link between the level of maintenance expense and forced outages, and due to the different ratemaking incentives that have existed for maintenance expenses versus replacement fuel costs (incentive to minimize operations and maintenance expense 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' recent rate cases in future AAA filings. The Commission's recent decision[17] to amend the FCA mechanism is expected to more closely align utilities' incentives regarding operations and maintenance costs and fuel costs. However, the Department will also continue to monitor outage costs on a going-forward basis.

H. CONTINGENCY PLANS FOR PLANT OUTAGES (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 in Docket No. E999/AA-08-995, 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.

[16] Source: Attachment 3.
[17] See the Commission's December 19, 2017 *Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements* in Docket No. E999/CI-03-802.

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 similarly 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 continued to attempt to generate a useful discussion and to encourage utilities to identify ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities.

As the utilities generally have not advanced this discussion, the Department suggested in its previous FYE16 AAA report (Docket 16-523) an industry standard used by the Nuclear Regulatory Commission (NRC) that the Commission may wish to consider to ensure that the rates utilities charge to ratepayers through the permissive FCA are reasonable:[18]

> The NRC holds utilities with licenses to operate nuclear generation facilities responsible for all events that occur at such facilities, whether due to work performed by a contractor or a direct employee of a utility. The Minnesota Commission may wish to use a similar standard regarding work done by contractors at non-nuclear facilities, including responsibility for incremental costs of replacement power due to forced outages caused by improper work on generation facilities. For example, since utilities have maintained that it is not feasible to hold contractors accountable for their work, a potential solution might be for the utilities to supervise contractors directly rather than rely on contractors to supervise themselves.

Specifically, the Department recommended that the Commission:

- 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 remove all foreign material from generation facility work areas.

[18] Source: Department's FYE16 AAA report at 18 in Docket No. E999/AA-16-523.

On December 19, 2017, the Commission issued its *Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements* (Order) in Docket No. E999/CI-03-802. The Commission's Order approved FCA reforms such that utilities will now have an incentive to minimize fuel costs, including those incurred for replacement power. Given the prospective implementation of FCA reform, the Department withdrew its previous recommendation regarding the two above-noted possible industry standards.[19]

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-end 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, the IOUs 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 report and December 31, 2014 reply comments 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 Electric was able to return insurance proceeds to ratepayers due to reimbursement for excess fuel oil needed during the startup of Sherco Unit 3. Xcel Electric stated the following:[20]

> 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.

[19] See page 3 of the Department's February 7, 2018 reply comments in Docket E999/AA-16-523.
[20] Part E, Section 2, page 5 of 5, Xcel's FYE15 AAA report.

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:

> 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 recommended in its previous FYE16 AAA report that the Commission consider holding utilities financially responsible for replacement power costs due to any failure to remove foreign material from generation facility work areas.

As discussed above, the Department withdrew, in its February 7, 2018 reply comments at 3 in Docket 16-523, its previous recommendation following the Commission's approval of FCA reforms in Docket No. E999/CI-03-802.

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 in Docket 03-30, the Commission provided specific true-up procedures applicable to Otter Tail's annual true-up filings.

On July 31, 2017, Otter Tail submitted a compliance report and proposal to implement a true-up debit (increase in rates) of $0.0004 per kWh. In comments filed on August 21, 2017, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up debit. The Commission's September 27, 2017 Order approved Otter Tail's true-up increase in rates beginning September 1, 2017.

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."[21] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order in Docket No. E002/M-10-161 regarding WM Renewable Energy.

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

[21] Source: Page 108 of 369 of Xcel Electric's FYE17 AAA report.

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 regarding Manitoba Hydro PPA.[22]

M. IN THE MATTER OF XCEL ENERGY'S REQUEST FOR APPROVAL OF A COMMUNITY SOLAR GARDEN PROGRAM, DOCKET NO. E002/M-13-867.

In its September 17, 2014 Order in Docket No. E002/M-13-867,[23] the Commission approved Xcel Electric's proposal to recover community solar garden program costs, including customer bill credits, additional Renewable Energy Credits (RECs), and unsubscribed energy, through the FCA mechanism. The first solar garden in Xcel Electric's program came online in September 2015. As noted by Xcel in Part E, Section 2, Page 4 of 4, of its FYE17 AAA Report, as of June 2017, the Company has been recovering monthly fuel costs associated with 26 community solar gardens.[24] Xcel's total Community Solar Garden Costs recovery in the FYE17 AAA period was $6,217,853 as shown on Part H, Section 9, Schedule 2, Page 1 of 1.

The Department reviewed Xcel Electric's Solar Garden Program Costs and was able to tie the solar costs to Xcel Electric's monthly FCA filings. Xcel stated that it allocates CSG costs to its various jurisdictions by dividing the costs into market and above market categories by reviewing solar garden production by hour and the corresponding Locational Marginal Price (LMP) at that hour. Market costs are allocated to jurisdiction based on sales, while costs above market are directly assigned to the Minnesota fuel clause.[25] Based on our review, the Department concludes that the Community Solar Garden Program costs included in Xcel Electric's FCA appear reasonable.

N. TRANSFORMER REPORTING

In its August 31, 2009 Order in Docket Nos. E999/AA-07-1130, E999/M-07-1028, and E999/M-09-602, the Commission required all utilities (except Dakota Electric Association) to provide the following information regarding transformers in their 2009 AAA filings:[26]

a. the number of transformers exceeding 100 kilovolts on their system and the size of each transformer;
b. an analysis as to whether they are maintaining in inventory or otherwise have reasonable access to a reasonable number of spare transformers in different sizes so as to avoid excessive replacement power costs during outages.

[22] Source: Attachment No. 14 of MP's FYE17 AAA report.
[23] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of its Proposed Community Solar Garden Program*, ORDER APPROVING SOLAR GARDEN PLAN WITH MODIFICATIONS, September 17, 2014, Docket No. E002/M-13-867.
[24] See Xcel Electric's Part H, Section 9, Schedule 1, Page 1 of 1 for more information on the 26 solar gardens.
[25] See Xcel Electric's Part H, Sections 1-10, page 6, Docket No. E999/AA-17-492.
[26] See Commission's August 31, 2009 Order in Docket No. E999/AA-07-1130, ordering point no. 16.

In its August 16, 2013 Order in Docket No. E999/AA-11-792, the Commission required all utilities (except Dakota Electric Association) to include the following information regarding transformers in future AAA filings:[27]

a. use Xcel's reporting format for the table found in Part H, Sections 1 – 8, page 3 of 6, but with the incorporation of all transformers on a utility's system, and with status of each transformer identified as one of these four categories: in-service standalone, in-service duplicate, on-order, or storage.
b. provide information regarding policy on backup strategies for transformers like MP did in their Attachment 13.
c. provide their policy for transformer maintenance.

Xcel Electric provided its transformer reporting in Part H, Sections 1-10, Page 2 of 6 of its FYE17 AAA Report. In addition, Xcel Electric provided a schedule showing the status of each transformer that exceeds 100 kilovolts in Part H, Section 4, Schedule 1 of its FYE17 AAA Report. However, the Department notes that Xcel Electric did not provide information regarding its backup strategies for transformers or their policy for transformer maintenance. The Department recommends that Xcel Electric provide this information in reply comments. The Department will provide its recommendation regarding Xcel Electric's transformer reporting after it has reviewed Xcel Electric's reply comments.

MP provided its transformer reporting in Attachment 13 of its FYE17 AAA Report. The Department notes that MP did not provide their policy for transformer maintenance. The Department recommends that MP provide this information in reply comments. The Department will provide its recommendation regarding MP's transformer reporting after it has reviewed MP's reply comments.

OTP provided its transformer reporting in Attachment H, Section 8 of its FYE17 AAA Report. The Department reviewed OTP's transformer reporting and concludes that the required information was provided in accordance with the Commission's August 16, 2013 Order. As a result, the Department recommends that the Commission accept OTP's transformer reporting for FYE17.

IV. TOTAL FUEL COST REVIEW

A. OVERVIEW

Minn. Rules 7825.2390 to 7825.2920 allow IOUs to use the cost per kWh from the most recent two-month moving average of energy costs (current period cost of energy) as an estimate or forecast of the energy cost per kWh for the current period. Minn. R. 7825.2400, subpart 13. This estimate of energy costs in the next month is a simple forecast based on the average cost of energy from the most recent two months. The Rules allow the utility to recover its current period cost of energy in both its base rates (where the base cost of energy is set) and its FCA

[27] See Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, ordering point no. 23.

(where changes to energy costs, as defined in the Commission's rules, are recovered), which totals the current period cost of energy. This is the calculation the utility must use to calculate the FCA, unless the utility has received a rule variance from the Commission allowing the utility to use a different method.

The Department notes that there are differences among the electric IOUs in how the fuel cost adjustment is calculated. Xcel Electric was granted a variance to charge FCA rates based on Xcel Electric's forecast of fuel costs in the upcoming month, rather than the two-month average cost per kWh required by Minnesota Rules. Further, Xcel Electric adjusts its rates to refund or recover previous over- and under-recoveries of its energy costs through a monthly true-up. DEA and OTP both have an annual true-up to refund or recover previous over- and under-recoveries of their energy costs. MP did not receive a rule variance to use a different method and, as a result, MP recovers its current period cost of energy on a monthly basis as provided by the Rules, and does not have a true-up mechanism.

B. DAKOTA ELECTRIC ASSOCIATION

Dakota serves about 105,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment 4 to this Report shows that DEA's resource adjustment includes $149,710,574 or $82.26/MWh in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[28] This amount is over 2 percent higher than the $80.10/MWh cost in FYE16.

DEA recovered $147,944,508 in fuel costs and thus under-recovered fuel costs in FYE17 by $1,766,066 or 1.18 percent.

Regulated utilities normally recover through their automatic adjustments only changes from the amounts set in a rate case for the cost of fuel and cost of energy obtained through purchased power agreements (PPAs); 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 makes Dakota's monthly over- and under-recoveries potentially greater than those experienced by utilities that only include fuel and PPA costs in their fuel clause. 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, Dakota calculates and applies an annual fuel-cost true-up factor based on these discrepancies.

[28] 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 FYE16 energy needs from power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).

C. MINNESOTA POWER

Minnesota Power serves about 144,000 electric customers in northeastern Minnesota. MP's fuel costs were $166,645,477 for FYE17.[29] MP under-recovered its fuel costs by $0.08 million in FYE17, or approximately 0.05 percent of its actual costs. Compared to FYE16 fuel costs of $18.79/MWh, MP's costs in FYE17 of $20.84/MWh were 10.9 percent higher.[30]

The Department notes that MP's level of under/over-recovery varies from month to month. In FYE17, MP's monthly under/over-recoveries ranged from a $1.4 million under-recovery (August 2016), to a $1.3 million over-recovery (September 2016).

D. OTTER TAIL POWER COMPANY

Otter Tail serves more than 61,000 Minnesota electric customers, primarily in western Minnesota. During the reporting period, OTP's total fuel costs were $58,637,860 or $24.04/MWh for OTP's Minnesota operations in FYE17.[31] This level is 2.4 percent higher than the $23.47/MWh cost in FYE16.[32]

During FYE17, Otter Tail experienced a 1.8 percent under recovery as a whole. As a result, the Commission's September 27, 2017 Order approved Otter Tail's true-up increase in rates beginning September 1, 2017.[33]

E. XCEL ELECTRIC

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had energy costs of $751,387,629 for FYE17, or $25.08/MWh.[34] This level is 1.4 percent higher than the $24.74/MWh cost in FYE16.[35]

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

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[29] Source: Attachment 5.
[30] Source: Attachment 8.
[31] Source: Attachment 6.
[32] Source: Attachment 8.
[33] Source: Commission's September 27, 2017 Order in Docket No. E017/M-03-30.
[34] Source: Attachment 7.
[35] Source: Attachment 8.

Sherco Unit 3 Litigation Update:

Following discovery from the Department, Xcel Electric provided an update as to the status of Xcel Electric's litigation against General Electric Co. with respect to the Sherco Unit 3 outage, in accordance with the Commission's June 2, 2016 Order in Docket No. E999/AA-13-599 et al.

The Commission stated the following on page 5 of its June 2, 2016 Order:

> Sherco 3's outage caused Xcel Electric to incur greater energy-related costs than it otherwise would have. The ongoing litigation between Xcel Electric and General Electric may well reveal facts about the steps each of those parties took, or failed to take, that contributed to the outage and related costs.
>
> Consequently the Commission agrees with the Department and OAG that it would be premature to render a decision about these matters at this time. But the Commission also concurs with Xcel Electric that it would be premature to initiate another proceeding to address this issue while Xcel Electric and General Electric are already engaged in a separate proceeding. Rather, the Commission will simply defer its decision on this issue until the Commission has a sufficient record regarding the recovery of the cost of replacement energy.
>
> Finally, the Commission concurs with all parties that it may act in the future to remedy any inequities that it finds in Xcel Electric's recovery of replacement energy costs from ratepayers. This may include directing Xcel Electric to refund any excessive cost recovery.

On September 21, 2018, the Department requested Xcel to provide an update as to the status of the Sherco Unit 3 litigation based on information to date, including but not limited to known next steps. In its October 1, 2018 response to the Department's discovery, Xcel stated that:

> On September 19, 2018, the Company reached a settlement with General Electric that resolves all claims in the pending litigation. The Company will soon make informational filings related to this settlement in Docket Nos. E002/GR-12-961, E002/GR-13-868, and E999/AA-18-373.

The Department will provide its analysis and recommendations regarding the Sherco Unit 3 settlement following its review of Xcel's above-mentioned informational filing (once it is filed) and Xcel's response to any follow-up discovery as needed.

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;
- 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 three 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.

On July 21, 2017, the Commission in Docket No. E999/AA-15-611 approved excluding the MISO Schedule 10 review in the AAA reports. The Commission noted that because the MISO Schedule 10 information is filed by electric utilities in their general rate cases, which provides parties the opportunity for full record development on these issues, the MISO Schedule 10 review is no necessary in the AAA reports.[36] As a result, the Department has excluded the MISO Schedule 10 review from our MISO Day 1 review below. The Department notes that there may no longer be a need for the below MISO Day 1 reporting, since MISO Day 1 has been in operation since 2002 and we have not seen much in the way of concerns that have negatively impacted customers. The Department will discuss with the electric utilities and the consumer advocates participating in the FCA reform proceeding (Docket 03-802), whether this MISO Day 1 reporting continues to be needed.

A. 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 several years ago, 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'

[36] See pages 5 and 6 of the Commission's July 21, 2017 Order in Docket No. E999/AA-15-611.

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 are being recovered over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

The utilities noted there are no new deferrals in the FYE17 AAA reports.

B. 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 three utilities indicated that no such instances occurred during the reporting period FYE17.

C. 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 three utilities indicated that no such instances occurred during the reporting period FYE17.

D. 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 of changes to MISO's tariffs on retail rates in Minnesota. Specifically:

- During the period July 1, 2016 to June 30, 2017, MISO submitted significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission and Energy Markets Tariff (TEMT or 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 "FERC Orders" tabs available under the "Legal" tab on the MISO home page.

- 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 Open Access Transmission Tariff (OATT) Business Practices efforts. Finally, they stated that they have been actively involved in the ongoing Regional Expansion and Cost Benefit Task Force (RECB).

- 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.

E. 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 noted that an overall net increase in transmission costs has occurred due to an increase in costs charged under Schedule 10, MISO's administrative charges, offset by a decrease in costs due to elimination of transmission rate "pancaking" and elimination of the MAPP or MAIN fee.

The utilities generally agreed to 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.

In its FYE17 and past AAA reports, Xcel Electric provided the following response[37] 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 basis, 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.

F. 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.

[37] Xcel's AAA report in Docket No. E999/AA-17-492 in Part I, Sections 1-7 page 7 of 8.

VI. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

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

MISO's Day 2 energy market[38] both did and did not change the way utilities provide service to customers. On one hand, as noted by the Commission in its December 20, 2006 Order *Establishing Accounting Treatment for MISO Day 2 Costs* (Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406), MISO's tariff re-characterized the way utilities provide electricity for the customers they are obligated to serve (native load customers[39]), including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any surplus or deficit from or to neighboring utilities. In contrast, under MISO's tariff, utilities sell all power from their electric generation and other resources into the wholesale market, and purchase power back from the market to provide electric service for their ratepayers.

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

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

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

over its entire footprint, based on participants' bids and offers and the limitations of the transmission system, with the optimized cost of supply.

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

First, because the Commission had not yet had sufficient opportunity to evaluate the parties' arguments, on April 7, 2005, the Commission provided temporary relief by permitting the parties to recover Day 2 costs through the fuel clause adjustment (FCA) on an interim basis subject to refund.[40]

Second, in its December 21, 2005 Order, after further analysis, the Commission concluded that only certain costs should be recovered through the FCA. In particular, the Commission concluded that the costs of administering the MISO Day 2 Market, listed in Schedules 16 and 17, were insufficiently related to energy or the types of costs previously recovered through the FCA to warrant FCA recovery. The Commission ordered the utilities to refund the balance to ratepayers.[41]

In addition, the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations. Finally, the Commission initiated an investigation into the best method for assuring low-cost electricity in Minnesota.[42] These basic principles are still in place.

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

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[40] *Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest* (April 7, 2005).
[41] *Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation* (December 21, 2005 Order).
[42] December 21, 2005 Order at Ordering Paragraph 10.

of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[43]

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[44] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize utilities to recover most Day 2 costs via their fuel clauses. In support of the proposal, the utilities agreed to make certain commitments, described further below.

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

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

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

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

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

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[43] *Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings* at 7-8.
[44] The Joint Report reflected the views of all parties except for what is now known as the Office of the Attorney General-Residential Utilities and Anti-Trust Division.

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the transmission grid. As noted in AAA filings since at least FYE07, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

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

C. OVERALL REVIEW OF MISO DAY 2 CHARGES

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

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

The Department's audit of MISO Day 2 charges started with the "MISO Day 2 Spreadsheet of Charges" as originally developed in the MISO Day 2 stakeholder process and as ordered by the Commission in its Final MISO Day 2 Order, Ordering Paragraph 7, part g. This MISO Day 2 spreadsheet of charges and additional support for MISO Day 2 net cost allocations, especially between retail and wholesale, was updated in the Commission's February 6, 2008 Order for the 2006 AAA, in Ordering Paragraphs 21 to 24. The Department has included all of the information request responses for MISO Day 2, Asset-Based Margins and ASM as DOC Attachment A for Xcel Electric, DOC Attachment B for MP, and DOC Attachment C for OTP.

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

Xcel Electric allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale/intersystem, and non-asset-based wholesale/intersystem. The Company's invoices from MISO combine Xcel Electric's two asset owners: NSPP (generator asset owner) and NSPT (Xcel's trading owner which handles non-asset-based transactions). Since Xcel Electric has two asset owners set up with MISO, the MISO invoices for a given month can be separated between NSPP and NSPT using the MISO daily settlements. A summary of MISO Day

2 charges assigned to the three categories is provided in Part J, Section 5, Schedule 7, page 13 of 13 of Xcel's Electric's FYE17 AAA Report. The Department notes that the amounts and totals reflected on Part J, Section 5, Schedule 7 are at the total-company level.

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

Table 4: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE11	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17
Net Costs	$195.9[45]	$196.6[46]	$200.5[47]	$222.9[48]	$101.7[49]	$54.6[50]	$87.9[51]

The Department notes that the total or net MISO Day 2 costs assigned to Xcel Electric's retail ratepayers have increased significantly from the FYE16 reporting period, but still remain quite low compared to previous periods (FYE11 – FYE15). The Department notes that this increase is consistent with the increase in MISO's locational marginal prices (LMPs) in FYE17.

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE17. The Department performed a limited review of some charge types showing significant changes between FYE16 and FYE17, as discussed below. In addition, the Department reviewed Xcel Electric's allocation of MISO Day 2 costs.

a) Day-Ahead Asset Energy

In its review, the Department noted that the amount of Day-Ahead Asset Energy assigned to retail ratepayers increased from 3,113,067 MWh and $93,607,099 in FYE16 to 4,803,192 MWh and $148,633,541 in FYE17. In DOC Information Request No. 25, the Department asked Xcel Electric to explain this increase.

Xcel provided the following response: [52]

> Hours where the Company made net purchases increased by 1,690,124 MWh, these amounts are assigned to Retail. Hours where the Company made net sales increased by 2,390,923 MWh, these amounts are assigned to Asset Based. For Day Ahead Asset

[45] Source: Xcel Electric's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 7, Page 13 of 13.
[46] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[47] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[48] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.
[49] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 13 of 13.
[50] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 13 of 13.
[51] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 7, Page 13 of 13.
[52] A copy of Xcel Electric's Response to DOC Information Request No. 25 is included in Attachment A to these comments.

> Energy in total, the Company switched year over year from purchasing 60,843 MWh to selling 639,956 MWh.
>
> The increase in total sales is partially related to Day Ahead load bids remaining constant combined with a significant increase in Day Ahead awards to low-cost wind generation as three new resources were offered to the market.
>
> The assignment between Retail purchases and Asset Based sales is directly related to the MISO market assigning the lowest cost generation currently available to serve load where the sum of the Company's hourly resource awards are less than or greater than the Company's hourly load obligation.

Based on the above, the Department concludes that Xcel Electric has adequately explained its increase in Day-Ahead Asset Energy charges assigned to retail ratepayers for FYE17.

b) Financial Transmission Rights Hourly Allocation

The Department noted that the amount of Financial Transmission Rights Hourly Allocation increased from ($21,996,610) in FYE16 to ($43,532,994) in FYE17. In DOC Information Request No. 26, the Department asked Xcel Electric to explain this change.

Xcel provided the following response:[53]

> The increase of $21,536,384 in Financial Transmission Rights Hourly Allocation revenue is primarily related to a transmission outage which caused strong congestion for several base load units between July and August of 2016. Related congestion cost of $19 million was offset by $21 million in related FTR revenue for a net benefit to customers of $2 million.

Based on the above, the Department concludes that Xcel Electric has adequately explained its increase in Financial Transmission Rights Hourly Allocation for FYE17.

c) Day-Ahead Congestion Rebate on Carve Out - Grandfathered

During our review, the Department noted that the amount of Day-Ahead Congestion Rebate on Carve Out – Grandfathered charges increased from $22,471 in FYE16 to $100,321 in FYE17. In DOC Information Request No. 27, the Department asked Xcel Electric to explain this change.

[53] A copy of Xcel Electric's Response to DOC Information Request No. 26 is included in Attachment A to these comments.

Xcel provided the following response:

> Day Ahead Congestion Rebate on Carve Out - Grandfathered represents a rebate of congestion paid on financial schedules considered to be grandfathered agreements. Grandfathered agreements are exempt from paying congestion cost. Congestion costs can be a credit or charge depending upon current network topology which changes hourly in the Day Ahead Market. The charge of $100,321 in Docket No. E999/AA-17-492 has an offsetting value of ($100,321) on the Day Ahead Financial Bilateral Transaction Congestion line.

Based on the above, the Department concludes that Xcel Electric has adequately explained its increase in Financial Transmission Rights Hourly Allocation for FYE17. Moreover, the Department agrees that this charge is offset by ($100,321) in Day-Ahead Financial Bilateral Transaction Congestion revenues for FYE17.

d) Allocation of MISO Day 2 Charges

The Department notes that Xcel Electric's total net MISO Day 2 costs/(revenues) totaled ($51,221,010) for retail and asset-based wholesale/intersystem in FYE17.[54] Of this amount, $87,563,778 in net costs were assigned to retail and ($139,101,700) in net revenues were assigned to asset-based wholesale/intersystem.[55]

The Department reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset-based wholesale/intersystem, and its non-asset-based wholesale/intersystem. The Department notes that Xcel Electric's allocations between retail and asset-based wholesale/intersystem are complex. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[56]

The Department asked Xcel Electric in DOC Information Request No. 22 if Xcel had changed any of the allocation methods used to allocate MISO Day 2 charges between retail and asset-based wholesale from the FYE16 to FYE17 reporting periods. Xcel Electric stated in its response that there have been no changes to the allocation methods for MISO Day 2 charges between retail and asset-based wholesale from the FYE16 to FYE17 reporting periods.

Based on our review, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting and allocations for FYE17.

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[54] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 7, Page 13 of 13.
[55] *Id.*
[56] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

2. Review of MP's MISO Day 2 Charges

Attachment 9 to Minnesota Power's FYE17 AAA Report contain MP's total MISO charges by month, as well as an estimate of the allocation of those charges across the Company's various customer categories. MP's total MISO charges (MISO Day 2 and ASM) and the amounts allocated to its retail customers in FYE17 increased significantly compared to FYE16 and FYE15, but still remain quite low compared to previous periods (FYE11 – FYE14) as shown in the below table.

Table 5: Minnesota Power MISO Day 2 & ASM Charges and Amounts Allocated to Retail

	Total MISO Charges		MISO Charges Allocated to Retail	
	Amount ($ millions)	Change from Prior Year	Amount ($ millions)	Change from Prior Year
FYE11	58.1		51.1	
FYE12	56.3	-3.1%	48.2	-5.7%
FYE13	58.3	3.6%	52.9	9.8%
FYE14	61.2	5.0%	58.4	10.4%
FYE15	39.2	-35.9%	40.8	-30.1%
FYE16	30.2	-23.0%	33.3	-18.5%
FYE17	44.6	47.7%	44.8	34.5%

Source: Attachment 9 to MP AAA Report

The Department notes that MP provided in response to DOC Information Request No. 14 parts (b) and (c) the breakout of the "Grand Total" of $44,597,707 (rounded to $44.6 million) as shown on page 77 of 80 of MP's Attachment 9 to MP's FYE17 AAA Report, into MISO Day 2 charges of $44.1 million and ASM charges of $0.5 million. Additionally, in response to DOC Information Request No. 14 part (a) MP clarified that footnote 1 on MP's Attachment 9 should be corrected to say MISO administrative charges were included in "base rates" and not "base cost of fuel."

As part of our review, the Department asked MP to explain the main drivers that caused the MISO Day 2 and ASM net costs to increase from $30.2 million for FYE16 to $44.6 million for FYE17 as shown on MP's Attachment 9 and in the above table. In response to DOC Information Request No. 15 parts (a) and (b), MP indicated that most of the increase for MISO Day 2 charges related to Asset Energy increasing by approximately $10 million and Energy Losses increasing by approximately $3 million from FYE16 to FYE17. MP noted most of the increase was caused by the increase in LMP (location margin price), since Day-Ahead LMP's at the hub MP.MP averaged $20.35 for FYE16 and escalated to $23.76 for FYE17. Additionally, MP noted that most of the increase for ASM charges was due to increases in Regulation Reserve Cost Distribution, Spinning Reserve Cost Distribution, and Supplemental Reserve Cost Distribution. MP noted that these three Distribution Charges that increased are MISO procurement costs that are distributed to Asset Owners (like MP) based on their load.

As part of our review, the Department asked MP to provide the MISO Bills that support the $6.232 million in MISO Day and ASM charges for April 2017. The Department also requested that MP support its cost allocation of $5.639 million to retail customers "FPE Retail" for April 2017. In response to DOC Information Request No. 17 parts (a) and (b), MP provided this information which the DOC considered to be reasonable.

The Department asked MP to explain why MP has financial transmission rights (FTRs) and auction revenue rights (ARRs) that sink outside of Minnesota. MP explained in response to DOC Information Request No. 18 that MP actively sells any excess energy to the wholesale market and has bilateral transactions that sink outside of Minnesota. The Department notes that the net revenue from excess energy sales are reflected in MP's asset-based margins that are provided to retail customers as discussed in the Asset-Based Margins section below.

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE17 AAA Report and concludes that they are reasonable.

The Department also reviewed Minnesota Power's allocation of its MISO charges across its various customer categories. The Department described Minnesota Power's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[57] Because those allocation methods have not changed, the Department will describe them only briefly in this report.[58]

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

Based on our review, the Department recommends that the Commission accept Minnesota Power's MISO Day 2 reporting and allocations for FYE17.

3. Review of OTP's MISO Day 2 Charges

OTP has allocated its MISO Day 2 charges across three categories historically. These categories consist of retail, asset-based wholesale and non-asset-based wholesale. OTP has also referred

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

[58] MP's response to DOC Information Request No. 12 confirmed that there have been no allocation changes for MISO Day 2 and ASM charges.

to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OPTW settlement standards. MISO Day 2 charges for non-asset-based wholesale are billed separately under the OTPD statement. A summary of MISO Day 2 charges assigned to the three categories is provided in Part H, Section 3, Attachment K of OTP's 2016-2017 AAA Report. The Department notes that amounts and total reflected in Attachment K are at the total-company level and not the Minnesota jurisdictional level.

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

Table 6: Otter Tail Power
Total MISO Day 2 Charges Assigned to Retail (Millions)

AAA Reporting Period	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Revenues	$113.8	$173.1	$102.6	$70.8	$94.1
Costs	$145.2	$215.3	$142.7	$111.5	$132.4
Net Costs	$31.4	$42.2	$40.1	$40.7	$38.3

Source: Part E, Section 10, Attachment I-1

The Department notes that one of the drivers for the level of OTP's MISO Day 2 charges is weather. The increase in net costs between 2012-2013 and 2013-2014 was driven in part by the extreme cold OTP's service territory experienced during the winter of 2013-2014. In response to Department Information Request No. 32, the Department asked OTP to explain fluctuations related to MISO Day 2 charges for Day-Ahead Non-Asset Energy Amount and Real-Time Congestion. OTP provided the following response:

> The DA non-asset energy charge type includes charges and credits related to all day-ahead interchange schedules and day-ahead financial schedules settled at commercial pricing nodes where an asset owner does not own an asset. Prior to November of 2015, the Otter Tail DA non-asset energy charge was primarily driven by two factors. The first being a credit received from MISO for energy injected by Western Area Power Administration to serve agency and municipal loads within the Otter Tail footprint. The second being a charge for exports of Otter Tail energy, leaving the MISO footprint, to serve Otter Tail load within the Western Area Power Administration footprint. Starting in November of 2015, as a result of Western Area Power Administration joining the Southwest Power Pool, Otter Tail began pseudo tying our load in the Western footprint back into the MISO footprint. Pseudo tying a load utilizes meter measurements and mathematical calculations to allow a balancing area (in this case MISO) to serve a load located geographically outside of its footprint. When the pseudo tie was

> initiated in November of 2015, load that had previously been viewed as an export to the Western footprint was now viewed as part of Otter Tail's MISO load. The export charge associated with the DA non-asset energy charge type was eliminated, leaving only the credit associated with Western's injection of energy into MISO to serve municipal and agency loads. The charge associated with serving the Otter Tail load geographically located in the Western footprint was shifted from the DA non-asset energy charge to the DA asset energy charge. Due to the magnitude difference between the DA non-asset energy charge and the DA asset energy charge it is difficult notice this change within the DA asset energy charge type.
>
> RT congestion charge/credit can vary considerably due to deltas between the DA and RT market. This is evident in reviewing the monthly swings associated with this charge/credit. The specific reasons for changes are difficult to pinpoint as they include many different variables, including changing DA to RT load schedules, DA to RT generation schedules, changing transmission constraints, and numerous other market factors.

The Department did a limited review of OTP's allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports.*[59] As noted in previous AAA dockets, OTP provided in response to DOC Information Request No. 30 that there have been no changes to the allocations for MISO Day 2 and ASM charge types.

Based on our review, the Department recommends that the Commission accept Otter Tail Power's MISO Day 2 reporting and allocations for FYE17.

D. ASSET-BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

A summary of Xcel Electric's asset-based margins for current and prior AAA reporting periods is provided below:

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

Table 7: Xcel Electric
Minnesota Asset-Based Margins (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17
Asset-Based Margins	$4.8[60]	$7.9[61]	$7.2[62]	$4.0[63]	$4.0[64]	$18.3[65]

The Department notes that Xcel Electric's asset-based margins increased significantly from $4.0 million in FYE16 to $18.3 million in FYE17. The Department recommends that Xcel Electric explain this increase in reply comments.

The Department reviewed Xcel Electric's asset-based margins for FYE17 to ensure asset-based margins were returned to ratepayers via the FCA. Similar to last year's review of asset-based margins in Docket No. E999/AA-16-523, the Department selected a monthly asset-based margin amount for testing. Specifically, the Department selected the asset-based margin of $14.094 million for March 2017[66] and tied this back to Xcel Electric's FCA. The Company provided the following in its response to DOC Information Request No. 23:

> The $14.094 million reported in the AAA report for March 2017 represents a portion of the total asset based revenues. The question above indicates it is a charge; however, it is a negative net cost and therefore is revenue. Cost of Goods Sold expenses are deducted from the total asset based revenue to calculate the total asset based margin. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the May 2017 fuel clause adjustment was $1,860,792.
>
> Please see below for additional detail:

[60] Per Xcel Electric's Response to DOC Information Request No. 35, Attachments A-B in Docket No. E999/AA-16-523; includes monthly true-up amounts.
[61] *Id.*
[62] *Id.*
[63] *Id.*
[64] *Id.*
[65] Per Xcel Electric's Response to DOC Information Request No. 24, Attachment A in Docket No. E999/AA-17-492; includes monthly true-up amounts.
[66] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 7, Page 9 of 13.

Minnesota Asset Based Margin Sharing	(Mar 2017) $- millions
(1) MISO Day 2 and ASM Intersystem Asset Based Revenue	$14.0
(2) Non-MISO Asset Based Revenue	$1.3
(3) Total Asset Based Revenue (1)+(2)	$15.3
(4) Less: Cost of Goods Sold	$11.6
(5) NSP System Asset Based Margins (3)–(4)	$3.7
(6) Less: Ratepayer Sharing (*)	$2.3
(7) Less: Other Jurisdictions Specific Adjustments	$0.8
(8) Other Jurisdictions' Pass-Through/Company Retention	$0.6
* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$2,665,023
Less: Jurisdiction Specific Adjustments	$804,231
Minnesota Net Portion	**$1,860,792**
Other NSP Jurisdictions	$411,357
Total NSP Ratepayers Sharing	$2,272,149

The Department traced the Minnesota Net Portion amount of $1,860,792 to Xcel Electric's May 2017 Fuel Clause Adjustment Report filed on April 28, 2017 in Docket No. E002/AA-17-330.[67] As a result, the Department concludes that Xcel Electric's March 2017 asset-based margins were appropriately passed back to ratepayers.

The Department recommends that the Commission not accept Xcel Electric's asset-based margins until the Company provides the requested information regarding the significant increase in asset-based margins in its reply comments. The Department will provide its recommendation regarding Xcel Electric's asset-based margins after it has reviewed Xcel Electric's reply comments.

[67] See Attachment 3, Page 1 of Xcel Electric's May 2017 Fuel Clause Adjustment Report in Docket No. E002/AA-17-330.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2017, and compares those margins to the revenue credit built into MP's base rates each year. As shown, the sum of MP's actual margins over the nine-year period ($337.9 million) exceeds its total credits provided in rates to customers of ($330.0 million) over the same period by 2.4 percent. Based on our review, the Department concludes that MP's asset-based margins appear to be reasonable.

The Department will continue to monitor MP's wholesale asset-based margins in future AAA filings.

Table 8: Minnesota Power Wholesale Asset-Based Margins
2009-2017

Calendar Year [a]	Actual Margin [b]	Revenue Credit Built into Base Rates [c]	Shareholder Benefit/(Loss) [d]=[b]-[c]	Percent Difference [e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
2014	$34.7	$37.7	($3.0)	-8.1%
2015	$39.8	$37.7	$2.1	5.6%
2016	$47.3	$37.7	$9.6	25.5%
2017	$34.3	$35.8	($1.5)	-4.2%
9 Yr. Total	$337.9	$330.0	$7.9	2.4%

Sources:
Actual Margin:
2009-2015: DOC August 25, 2016 *Review of the 2014-2015 Annual Automatic Adjustment Reports Part II, page 15.*
2016 Actual: MP Response to DOC Information Request No. 9 in Docket No. E999/AA-16-523.
2017 Actual: MP's response to DOC Information Request No. 13 in Docket No.E999/AA-17-492.
Revenue Credit in Base Rates:
2009: May 4, 2009 Order in Docket No. E015/GR-08-415
2010-2016: November 2, 2010 Order in Docket E015/GR-09-1151
2017: J.Pierce Supp. Direct p. 10 & Sch. 5 p. 17 Docket E015/GR-16-664

3. OTP

A summary of Otter Tail's asset-based margins for current and prior AAA reporting periods is provided below

Table 9: Otter Tail Power
Minnesota Asset-Based Margins[68]

AAA Reporting Period	FYE13	FYE14	FYE15	FYE16	FYE17
Asset-Based Margins	$2,910,644	$5,761,238	$1,545,701	$11,812	$826,096

Source: Part H, Section 3, Attachment K, page 26 of 26

The Department notes that OTP's asset-based margins have significant fluctuation from year-to-year as shown on the above table. The fluctuations of asset-based margins appears to be caused largely by the amount of excess energy available for sales, since the MWhs available vary from year-to-year, and the LMP at the time in which these asset based margins were made. The Department reviewed OTP's asset-based margins for FYE17 to ensure asset-based margins were returned to ratepayers via the FCA. The Department asked OTP in DOC Information Request No. 34 to provide the asset-based margins returned to ratepayers via the fuel clause for FYE17 reporting period. Based on our review of OTP's response to DOC Information Request No. 34, including Attachments 1 and 2 and an additional spreadsheet that the Department requested and received from OTP on October 9, 2018 that shows the July 2016 asset based margin give-back through the FCA, the Department concludes that OTP has returned its asset-based margins through the monthly FCAs for FYE17. Based on our review, the Department concludes that OTP's asset-based margins appear to be reasonable. The Department will continue to monitor OTP's wholesale asset-based margins in future AAA filings.

E. DOC INVOLVEMENT IN MISO PROCESSES

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

[68] Per Otter Tail's Response to DOC Information Request No. 35, Attachments A-B; includes monthly true-up amounts.

The Department also participates in MISO issues via our Public Consumer Group Sector for sector voting on issues largely through MISO AC and PAC Meetings, Hot Topic Comments, and various comments to FERC on matters such as: Return on Equity (ROE) Complaint, ROE Incentive Adders, and Prorated Accumulated Deferred Income Tax issue.

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

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

The Department concludes that the review of MISO Day 2 charges and allocations are complex, due to the volume of information related to these transactions, the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions and some of the utilities' fuel clause ratemaking processes. Nonetheless, based on our review, the Department recommends that the Commission accept the utilities' MISO Day 2 reporting for FYE17.

VII. ANCILLARY SERVICES MARKET (ASM)

A. BACKGROUND

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

These ancillary capabilities are as follows:

- <u>Regulation service</u>: having generation operating and able to change their MW output (up or down) to respond to changes in load on a second-by-second basis;
- <u>Spinning Reserve service</u>: having generation on line (spinning) at reduced output, so that it can immediately provide replacement power in the event of an unscheduled outage at another generation unit;
- <u>Supplemental Reserve service</u>: having generation readily available off-line and capable of starting and beginning to generate within ten (10) minutes to respond to an unscheduled outage at another generation unit; and
- <u>Energy Imbalance service</u>: providing energy between entities, such as between a utility and a municipal load-serving entity (which is typically a wholesale customer of the utility), to account for the difference between the amount scheduled during a

period (such as an hour) and the amount actually delivered (which may be more or less than the amount scheduled). Energy Imbalance service could be settled either by an "in kind" exchange of energy in a later period, or financially.

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

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

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

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

1. The Commission accepts the quarterly reports filed by the three utilities under the March 17, 2009 order in this case.

2. The Commission finds that the record demonstrates overall benefits from the three utilities' participation in the MISO ancillary services market and that the record supports the

continued use of the Fuel Clause Adjustment to pass through the costs and revenues associated with that participation. The three utilities are authorized to continue using the Fuel Clause Adjustment to pass through the costs and revenues associated with their participation in the MISO ancillary services market.

3. With the exception of Contingency Reserve Deployment Failure Charges and Excess/Deficient Energy Charges, the Commission removes the "subject to refund" provisions of the March 17, 2009 order for both past and future ancillary services market costs passed through the Fuel Clause Adjustment.

4. All costs and revenues associated with the utilities' participation in the MISO ancillary services market remain subject to the normal review, approval, and recovery procedures that apply to costs and revenues passed through the Fuel Clause Adjustment.

5. The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 *et seq*., including the annual filing required there under. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings, which are due in September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.

6. The three utilities shall continue to monitor and report all negative benefits (costs) of participation in the MISO ancillary services market and shall work with MISO to ensure that negative benefits occur, if at all, for limited periods of time and with minimal financial impact.

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

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

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

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

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

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

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

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

New Ramp Product

The Department notes that, beginning in May 2016, MISO implemented new Ramp Capability Product, and with it, two new charge types: Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount. MISO developed the Ramp Capability Product to provide additional operational flexibility to better respond to variations in load served by dispatchable resources caused by forecast error, variations in intermittent generation, and generation units not following dispatch signals.

Prior to the implementation of the Ramp Capability Product, when MISO did not have sufficient ramp capabilities to meet a sudden increase in load served by dispatchable resources, it was forced to call on units providing operating reserves to generate electricity to meet the increased load. At times, this resulted in a shortage of operating reserves and led to a spike in prices for energy or operating reserves, or both. It is cost effective for MISO to dispatch a higher-cost generator in order to have spare capacity at a lower-cost generator with better (i.e. faster) ramp capabilities available to meet fluctuations in demand.

The two new charges, the Day-Ahead and Real-Time Ramp Capability Amounts, are the charge types through which MISO market participants that provide ramp capabilities are compensated. The cost of providing ramp capabilities is allocated across all load and exports in the MISO energy market and billed via the Real-Time Revenue Neutrality Uplift Amount, an existing MISO Day 2 charge type that is already included in the fuel clause.

Because the Ramp Capability Product relates directly to operating reserves and energy pricing, is similar to ancillary service, and its cost is recovered through the Revenue Neutrality Uplift charge, which is already recovered through the fuel clause, the Department concludes that it is reasonable for utilities to include the Day-Ahead and Real-Time Ramp Capability Amounts in the fuel clause. If those two new charge types were to be excluded from the fuel clause, ratepayers would have to pay for the costs of ramp capabilities (via the Real-Time Revenue Neutrality Uplift Amount), but would not receive any of the revenues.

The Department addressed the two ramping products in Xcel's, MP's and OTP's ASM sections below.

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE16 AAA filing in Part J, Section 5, Schedules 8 to 16 and in Part J, Section 6 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric stated the following regarding overall ASM market performance:[69]

> During the 2016-2017 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject.
>
> The 2016 summer (June, July and August) temperatures were warmer than those of the previous two summers, with the South Region experiencing warm temperatures in June, and the entire footprint seeing higher temperatures in July and August. A Maximum Generation Emergency Event occurred on July 21, 2016, the first since the 2014 Polar Vortex and the first summer event

[69] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 6, Pages 1-2.

> since 2012. The 2016 average summer load was 86.4 GW, 3.0% higher than the 2015 average summer load. Warmer temperatures and higher loads produced an increase in energy prices. Energy prices for the 2016 summer increased 3.7% from the 2015 summer's low prices. The 3-month average Day-Ahead LMP for summer 2016 was $29.55/MWh and the 3-month average Real-Time LMP was $29.30/MWh. Fossil fuel prices in the 2016 summer decreased when compared with the 2015 summer: Chicago Citygate gas prices declined 7.5% and Powder River Basin coal prices decreased 25%.
>
> The 2017 winter (December 2016, January and February 2017) was characterized by warmer than normal temperatures across the MISO footprint. The average load decreased from 75.4 GW, 2016 winter, to 74.8 GW, 2017 winter. The average Day-Ahead and Real-Time system-wide LMPs for the 2017 winter were $28.18/MWh and $28.18/MWh, respectively, an increase of 30.5% and 33.4%, respectively, when compared to the 2016 winter. Fossil fuel prices increased during the 2017 winter when compared to the 2016 winter: Henry hub gas prices averaged approximately $3.23/MMBtu, an increase of 54.9%, and Powder River Basin coal prices averaged $0.64/MMBtu, an increase of 10.4%.
>
> Wind energy's contribution to energy production totals continued to increase and was 10.2% for the 2017 winter increasing from 8.1% for the 2016 winter. The total wind production increased 19.5%, and the capacity factor increased from 38.2% to 42.6% 2017 winter over 2016 winter. MISO set a new wind output record of 13.7 GW on December 7, 2016. The December 2016 total wind production of 5,687 GWh was an all-time monthly high for MISO.
>
> The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its 2016 State of the Market Report that "ASM continued to perform with no significant issues in 2016." The Market Monitor also noted prices for regulating reserves and spinning reserves rose slightly in 2016, but remained reasonable. [Footnotes omitted]

The Department notes that Xcel Electric's net ASM charges/(revenues) totaled $6,116,843 for retail and asset-based wholesale/intersystem in FYE16.[70] This amount includes $8,348,742 in net costs that were assigned to retail and ($2,231,899) in net revenues that were assigned to asset-based wholesale/intersystem.

[70] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 13, Page 13 of 13.

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

Table 10: Xcel Electric
Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17
Net Costs	$13.9[71]	$24.7[72]	$23.5[73]	$24.6[74]	$23.0[75]	$8.3[76]

The Department notes that Xcel Electric's retail ASM costs have decreased significantly in FYE17 when compared to previous AAA reporting periods.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE16.[77] Xcel Electric shows net ASM savings of $2.3 million for the total NSP system and $1.7 million for the Minnesota jurisdiction. Xcel Electric stated that these net savings are associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint. In addition, Xcel Electric stated that its net savings calculation did not include any additional benefits that have accrued to ratepayers for the reduction in regional regulatory reserve requirements.

1) Excessive/Deficient Energy Deployment Charges (EDEDC)

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

The Department notes that Xcel Electric's total system EDEDC increased from $679,156[78] in FYE16 to $1.1 million[79] in FYE17.

According to Xcel Electric, a certain level of EDEDC is unavoidable given the current design of the ASM market because the benefits of offering resource flexibility and the potential costs of missing targets are appropriately weighed against procuring reserves elsewhere in the market or other NSP resources. Xcel Electric stated that its ASM net benefit calculation is a measure of the extent to which Xcel Electric has struck the appropriate balance between too much or too

[71] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[72] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[73] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[74] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 13, Page 13 of 13.
[75] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 13, Page 13 of 13.
[76] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 13, Page 13 of 13.
[77] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 6, Page 3 of 6.
[78] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 6, Page 3 of 4.
[79] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 6, Page 5 of 6.

little flexibility being offered to MISO. Xcel Electric stated that its ASM net benefit of $2.3 million would not have been achievable if Xcel Electric had been offering ramp rates for enough units to all but eliminate the chance of incurring EDEDC charges. The Company also stated that:

> To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants on a daily basis to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected – and prudent – in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.
>
> In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in EDEDC charged to the Company began in January 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase was offset by an increase in the revenues received by the Company for Regulation. During the period of July 2015 through June 2016, EDEDC charges have declined by $17,791 as compared to the 2015 AAA period, ending June 30, 2015.

Based on the above, the Department concludes that Xcel Electric's EDEDC charges for FYE17 appear reasonable.

2) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE17 in Part J, Section 6 of its filing. CRDFC amounts are incurred when generation or demand response resources fail to deploy contingency reserves at or above the contingency reserve deployment instruction. These charges are assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

The Department notes that Xcel Electric's total system CRDFC decreased from $22,352 in FYE16 to $4,629 in FYE17. Regarding its FYE17 CRDFC, Xcel stated that:

Part J, Section 6, Schedule 3 shows NSP incurred a total of $4,629 in CRDFC during the 2016-2017 AAA reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless of whether MISO has 15 minutes to meet the standard or less than 10 minutes.

The charges were not the result of any oversight or error by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy reserves from another generator in its fleet, and would have incurred increased energy costs that were recovered in the FCA.

The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.

In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100% of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

Based on the above, the Department concludes that Xcel Electric's CRDFC charges for FYE17 appear reasonable.

3) 8a Real-Time Non-Excessive Energy Amount - System

During our review of ASM charges for FYE17, the Department noted that Xcel Electric's Real-Time Non-Excessive Energy Amount – System charges for July 2016 increased significantly from $546,921[80] in July 2016 to $2,357,643[81] in July 2017. In DOC Information Request No. 29(D), the Department asked Xcel Electric to explain this increase. Xcel Electric stated the following in its response:

> The Real Time Non Excessive Energy Amount of $2,357,643 in Docket No. E999/AA-17-492 is a net value comprising approximately $200 million in gross sales and buybacks. The Real Time sale to buyback ratio increased slightly from this perspective. The increase could be attributed to a single unit that tripped offline on three different days in August 2016.

The Department recommends that Xcel Electric provide in reply comments the specific generating unit and reasons that this unit tripped offline on three different days in August 2016, which resulted in increased Real-Time Non-Excessive Energy Amount – System charges. The Department will make its recommendation regarding Xcel Electric's Real-Time Non-Excessive Energy Amount – System charges after it has reviewed Xcel Electric's reply comments.

4) New Ramp Product: Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount

As explained in DOC's February 7, 2018 Response Comments in Docket 16-523, Xcel Electric included two new MISO charge types (Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount) in their existing ASM Day-Ahead Regulation Amount and Real-Time Regulation Amount. For clarification purposes, the Department recommended that Xcel Electric report these two new charges as separate line items rather than combining them with existing ASM charge types in future AAA Reports. The Commission agreed with the Department's recommendation and required Xcel Electric to report these charges as separate line items in future AAA Reports in its March 16, 2018 Order in Docket No. E999/AA-16-523.[82]

The Department notes that the instant petition was filed on September 1, 2017, before the Commission's March 16, 2018 Order. As a result, the Department understands that these two new charge types are not separately listed in Xcel Electric's FYE17 initial filing, and therefore are still included in Xcel Electric's existing ASM charge types. The Department will continue to

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[80] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 8, Page 1 of 12.

[81] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 8, Page 1 of 12.

[82] See Commission's March 16, 2018 *Order Accepting Reports and Setting Additional Requirements* in Docket No. E999/AA-16-523, ordering point no. 6.

monitor this issue and expects that Xcel Electric will record these two new charge types on separate line items beginning with its FYE18 AAA Report. However, the Department recommends that Xcel provide in reply comment the amounts of the new ramping products included in the reported FYE17 ASM charges.

The Department will make its overall recommendation regarding Xcel Electric's FYE17 ASM reporting after it reviews Xcel Electric's reply comments.

C. MP

1. Overall Review of ASM Costs and Revenues

MP addresses ASM costs and benefits in Attachment 10 to its FYE17 AAA Report. MP reported a net cost of $512,428 for FYE17, compared to net costs of $82,782 for FYE16, $161,920 for FYE 15 and $303,890 for FYE14. As part of our review, the Department asked MP to explain the main drivers that caused the MISO Day 2 and ASM net costs to increase from $30.2 million for FYE16 to $44.6 million for FYE17 as shown on MP's Attachment 9. In response to DOC Information Request No. 15 parts (a) and (b), MP provided that most of the increase for MISO Day 2 charges related to Asset Energy increasing by approximately $10 million and Energy Losses increasing by approximately $3 million from FYE16 to FYE17. MP noted that most of the increase was caused by the increase in LMP, since Day-Ahead LMP's at the hub MP.MP averaged $20.35 for FYE16 and escalated to $23.76 for FYE17. Additionally, MP noted that most of the increase for ASM charges was due to increases in Regulation Reserve Cost Distribution, Spinning Reserve Cost Distribution, and Supplemental Reserve Cost Distribution. MP noted that these three Distribution Charges that increased are MISO procurement costs that are distributed to Asset Owners (like MP) based on their load.

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

2. Real-Time Excessive/Deficient Energy Deployment Charges and Real-Time Contingency Reserve Deployment Failure Charges

The Department reviewed MP's Real-Time Excessive/Deficient Energy Deployment and the Contingency Reserve Deployment Failure charges, since these are basically performance penalties. The Department notes that MP's Real-Time Excessive/Deficient Energy Deployment charge amount increased slightly to $78,454 in FYE17, compared to $60,829 in FYE16 and was very similar to the $78,916 incurred in FYE15. Additionally, MP incurred only $197 in Contingency Reserve Deployment Failure charges during FYE17, compared to charges of $0 in FYE16, $288 in FYE15 and $2,757 in FYE14. Overall these charges continue to be minimal.

3. New Ramp Project: Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount

The Department notes that, beginning in May 2016, MP included two new MISO charge types in its fuel clause: Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount. MP's Day-Ahead and Real-Time Ramp Capability Amounts during May and June of 2016 totaled approximately negative $1,600 (that is, a credit, or reduction, to MP's total MISO charges). In FYE 2017, the Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amounts totaled a negative $20,780 (that is, a credit, or reduction to MP's total MISO charges). These charge types are associated with MISO's new Ramp Capability Product, which was implemented on May 1, 2016. MISO developed the Ramp Capability Product to provide additional operational flexibility to better respond to variations in load served by dispatchable resources caused by forecast error, variations in intermittent generation, and generation units not following dispatch signals.

Prior to the implementation of the Ramp Capability Product, when MISO did not have sufficient ramp capabilities to meet a sudden increase in load served by dispatchable resources, it was forced to call on units providing operating reserves to generate electricity to meet the increased load. At times, this resulted in a shortage of operating reserves and led to a spike in prices for energy or operating reserves, or both. It is cost effective for MISO to dispatch a higher-cost generator in order to have spare capacity at a lower-cost generator with better (i.e. faster) ramp capabilities available to meet fluctuations in demand.

The two new charge types included in MP's fuel clause, the Day-Ahead and Real-Time Ramp Capability Amounts, represent revenue paid to MISO market participants that provide ramp capabilities. The cost of providing these two ramp capabilities is allocated across all load and exports in the MISO energy market and billed via the Real-Time Revenue Neutrality Uplift Amount, an existing charge type that is already included in the fuel clause.

Because the Ramp Capability Product relates directly to operating reserves and energy pricing, is similar to ancillary service, and its cost is recovered through the Revenue Neutrality Uplift charge, which is already recovered through the fuel clause, the Department concludes that it is reasonable for MP to include the Day-Ahead and Real-Time Ramp Capability Amounts in its fuel clause. If those two new charge types were to be excluded from the fuel clause, ratepayers would have to pay for the costs of ramp capabilities (via the Real-Time Revenue Neutrality Uplift Amount), but would not receive any of the revenues.

4. Schedule 17, MISO Administrative Costs for ASM

Attachment 10, Table 10-C on page 5 of 12 of Minnesota Power's filing compares MP's MISO Schedule 17 charges prior to the start of the ASM market to its Schedule 17 charges in FYE17. In FYE17, average monthly MISO Schedule 17 charges were $138,524, or $2,399 higher than the average monthly charges prior to the start of the ASM market. This equates to an average monthly increase of $0.00089 per MWh. This comparison attempts to identify the MISO Schedule 17 charges that are related to ASM.

The Department reviewed MP's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept Minnesota Power's ASM reporting.

D. OTP

In Part H, Section 4, Attachment L its FYE17 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. OTP's Schedule 1 shows that OTP is a net purchaser for the period FYE17 of $24,409 for ASM products (Regulation, Spinning Reserve, and Supplemental Reserve). OTP noted in Part H, Section 4, Attachment L, that ASM allows generators that have been backed down to minimum generation levels to still provide spinning reserves. OTP also noted that as a result of ASM-regulation, the market determines the most cost-effective regulation and energy, which provides benefits to OTP's customers. Overall, OTP noted that ASM has allowed OTP the ability to more fully utilize its generation assets to the benefit of its customers.

OTP allocates all ASM charges on a per-MWh approach, netting costs and benefits of the various charges. As noted in response to DOC Information Request No. 30, OTP has not changed any of its allocation methods for ASM.

1. Real-Time Excessive/Deficient Energy Deployment Charges and Real-Time Contingency Reserve Deployment Failure Charges

According to OTP on page 185 of their FYE17 AAA Report, the Real-Time Excessive/Deficient Energy Deployment Charge amount represents the charge to an Asset Owner owning generation where the Asset Owner's unit fails to follow Setpoint instructions for four consecutive intervals within 1 hour without an exemption. This charge consists of taking back any cleared Day-Ahead Regulation Operating Reserve payment and any cleared Net Real-Time Regulation payment and also assesses a prorated share of the Day-Ahead and Real-Time Regulation Market cost. During the reporting period there was a total of ($6,783) of penalties assessed to Otter Tail units (Schedule 1 of Part H, Section 4, Attachment L, column R, line 17). These are normally mechanical failure situations where the unit fails to follow dispatch for a short time period while small repairs are made.

The Real-Time Contingency Deployment Failure Charge amount represents the charge incurred by resources that fail to deploy contingency reserves at or above the Contingency Reserve Deployment Instruction. Again, these would normally be short intervals where some mechanical failure occurred. For the reporting period, there was a total of $0 in charges (Schedule 1 of Part H, Section 4, Attachment L, column R, line 16).

The Department notes that the total deployment charges/penalties of $6,783 were relatively minor for the reporting period FYE17.

2. *Real-Time Non-Excessive Energy*

The Department asked OTP to explain the increase in the Real-Time Non-Excessive Energy amount from $3,205,717 for FYE16 to $3,879,203 for FYE17. OTP provided in response to DOC Information Request No. 32 the following response to explain the cause for this increase:

> The RT ASM non-excessive energy charge type is for credits and charges associated with generation imbalance between day-ahead and real-time schedules. The charge or credit is determined by subtracting the day ahead schedule (MWs) from the real time schedule (MWs) and multiplying that MW delta by the real-time LMP. Changing schedules and increased volatility in real-time pricing can result in substantial variability in the RT ASM non-excessive energy charge. The primary reason driving charges and credits in the RT ASM non-excessive energy charge type are due to changing market conditions. As market conditions change, MISO calls for updated dispatch instructions, resulting in changes between the DA and RT generation schedules, which in turn drive the charges and credits associated with the RT ASM non-excessive energy charge type. There are occasions where Otter Tail requires a change in the DA schedule relative to the RT schedule, including generator forced outage, testing, de-rates, etc.

3. *New Ramp Project: Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount*

In OTP's October 9, 2017 reply comments, OTP provided the following explanation for the new ASM – Ramp Capability Products:

> Otter Tail has included these charge types in the fuel clause beginning with the energy adjustment rate that was effective July 2016. The July 2016 rate was calculated based on April and May 2016 data which was inclusive of these new Ramp Capability charge types. In Otter Tail's Initial Filing in this Docket, Part E Section 10 Attachment I-1, which provides the detail of MISO Day 2 Charges by Charge Group, shows the DA and RT Ramp Product charge types and associated monthly amounts reflected on lines 47 and 48 of pages 21, 23, and 25 of 26. These same amounts are also reflected in Part H, Section 3, Attachment K pages 21, 23, and 25 of 26 in Otter Tail's Initial Filing.
>
> The net total (revenues less costs) for these charge types for the July 2015 to June 2016 reporting period was net revenue of $1,264.
>
> Evidence of these charges being included in Otter Tail's monthly energy adjustment filings can also be found in Attachments A

> through E of those filings, beginning with the July 2016 rate. Otter Tail has continued to include these charge types in the monthly fuel clause rate calculations since their inception.

The Department notes that, for FYE17, the total (revenues less costs) for Day-Ahead and Real-Time Ramp Products was $29,788 net revenue on a total-company basis, and was correctly assigned to retail customers, as shown on OTP's AAA Report on Part H, Section 3, Attachment K, on page 25 of 26. OTP explained on page 185 of its FYE17 AAA Report that the MISO ramp capability product was introduced in May of 2016, and was designed to increase reliability and decrease the cost of serving load. MISO's ramp capability product adjusts (fine-tunes) system ramp capability in each dispatch interval as needed, using a 10-minute forecast of net load plus forecast uncertainty. Creating additional ramp capability involves shifting MWs between slower-ramping and faster-ramping units. Generators providing ramp capability are entitled to potential revenues/charges in both the day-ahead and real-time markets. The cost MISO incurs by creating additional ramp capability is offset by the reduced likelihood of insufficient ramp and shortage pricing. MISO's ramp capability product has resulted in a net benefit of $15,155[83] for the AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 15).

The Department reviewed OTP's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept OTP's ASM reporting.

VIII. FUEL COSTS AND EFFECTS ON CUSTOMER BILLS

Attachment 9 shows various aspects of fuel charges and the effects on customers' bills for informational purposes.

1. Average Residential Bills for 2016

Attachment 9 shows the monthly average bills for residential customers in calendar year 2016. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges. Overall, Dakota Electric had the highest average monthly residential bill of $87.89, followed by Otter Tail at $82.10, Xcel Electric at $79.17 and Minnesota Power with the lowest average of $62.96 per month.

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

Attachment 9 shows the amounts that residential customers paid during calendar year 2016 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 12.33¢/kWh, Xcel Electric with an average of 10.97¢/kWh, Otter Tail with an average of 7.99¢/kWh, and Minnesota Power 7.33/kWh. However, the Department notes that, because utilities recover

[83] The $15,155 in net revenues for Ramp Products is the Minnesota Jurisdictional amount based on $29,788 total-company amount times the Minnesota Jurisdictional allocator of 50.8771479%.

different amounts of fixed costs in the energy charges, this comparison is not as useful as the bill comparison in item 1 above.

IX. CONCLUSIONS AND RECOMMENDATIONS

A. SECTION II, FILING REQUIREMENTS

Based on our review, Xcel provided the required information in Part F of its Auditor's Report in compliance with the Commission's ordering paragraph 7 in Docket No. E999/AA-15-611 regarding additional requirements for the independent auditors report. However, MP and OTP did not address Commission's ordering paragraph 7 in their Auditor's Report; as a result, the Department recommends that MP and OTP address in their reply comments the missing compliance requirement.

B. SECTION III, COMPLIANCE DOCKETS

The Department recommends that the Commission accept Xcel Electric's compliance filing, including the high-level cost allocation test between wholesale and retail customers for June, July, and August of 2017. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings, as required by Docket No. E002/CI-00-415, Ordering Paragraph No. 2.

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.

The Department recommends that the Commission accept Xcel Electric's Wind Curtailment compliance filing in the FYE17 AAA docket.

The Department notes that Xcel Electric's FYE17 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.

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

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' recent rate cases in future AAA filings. The Department will also consider ongoing outage costs on a going forward basis.

Since the Commission approved FCA reforms in Docket No. E999/CI-03-802, the Department withdrew, in its February 7, 2018 reply comments at 3 in Docket No. E999/AA-16-523, its previous recommendation regarding two possible industry standards for FCA reform.

The Department concludes that Xcel Electric complied with the 2010 Order in Docket No. E002/M-10-161 regarding WM Renewable Energy.

The Department concludes that MP provided the required reporting information in compliance with the Commission's Order in Docket No. E015/M-10-961 regarding Manitoba Hydro PPA.[84]

The Department concludes that the Community Solar Garden Program costs included in Xcel Electric's FCA appear reasonable.

The Department recommends that Xcel Electric provide information regarding its backup strategies for transformers and its policy for transformer maintenance in reply comments. The Department will provide its recommendation regarding Xcel Electric's transformer reporting for FYE17 after it has reviewed Xcel Electric's reply comments.

The Department recommends that MP provide its policy for transformer maintenance in reply comments. The Department will provide its recommendation regarding MP's transformer reporting for FYE17 after it has reviewed MP's reply comments.

The Department recommends that the Commission accept OTP's transformer reporting for FYE17.

C. SECTION IV, TOTAL FUEL COST REVIEW

The Department will provide its analysis and recommendations regarding the Sherco Unit 3 settlement following its review of Xcel's above-mentioned informational filing (once it is filed) and Xcel's response to any follow-up discovery as needed.

D. RECOMMENDATIONS FOR MISO DAY 1

The Department notes that there may no longer be a need for the MISO Day 1 reporting, since the MISO Day 1 has been in operation since 2002 and we have not seen much in the way of concerns that have negatively impacted customers. The Department will discuss with the IOU electric utilities and the consumer advocates participating in the FCA reform proceeding (Docket 03-802), whether this MISO Day 1 reporting continues to be needed.

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.

---

[84] Source: Attachment No. 14 of MP's FYE17 AAA report.

E. MISO DAY 2 REPORTING AND ALLOCATIONS

- The Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting and allocations for FYE17.
- The Department recommends that the Commission accept MP's MISO Day 2 reporting and allocations for FYE17.
- The Department recommends that the Commission accept OTP's MISO Day 2 reporting and allocations for FYE17.

F. RECOMMENDATIONS FOR ASSET-BASED MARGINS

- The Department recommends that Xcel Electric explain in reply comments the significant increase in asset-based margins from $4.0 million in FYE16 to $18.3 million in FYE17. The Department will provide its recommendation regarding Xcel Electric's asset-based margins for FYE17 after it has reviewed Xcel Electric's reply comments.
- The Department concludes that MP's asset-based margins appear to be reasonable.
- The Department concludes that OTP's asset-based margins appear to be reasonable.

G. RECOMMENDATIONS FOR ANCILLARY SERVICES MARKET

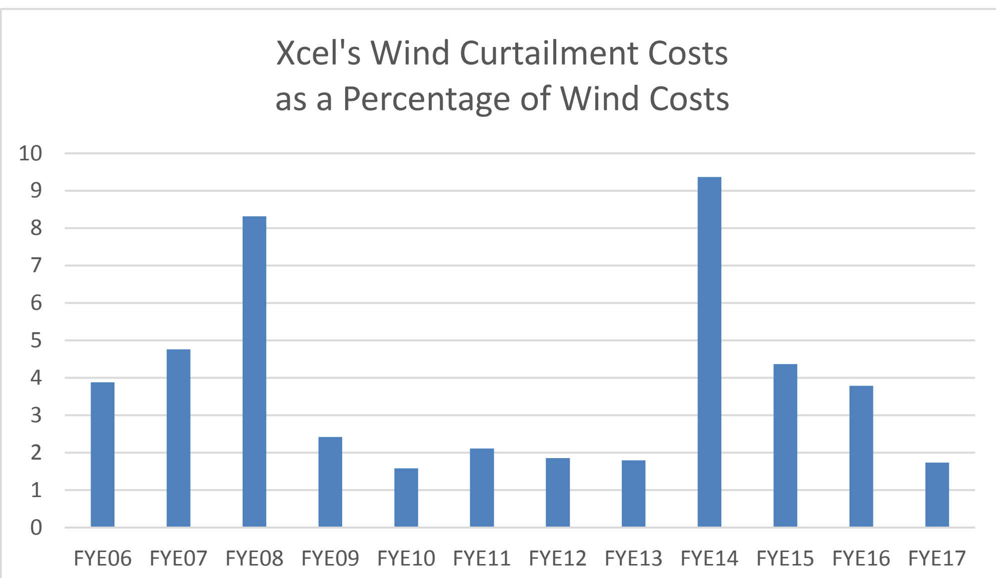
- The Department concludes that Xcel Electric's FYE17 EDEDC charges appear reasonable.
- The Department concludes that Xcel Electric's FYE17 CRDFC charges appear reasonable.
- The Department recommends that Xcel Electric provide in reply comments the specific generating unit and reasons that this unit tripped offline on three different days in August 2016, which resulted in increased Real-Time Non-Excessive Energy Amount – System charges. The Department will make its recommendation regarding Xcel Electric's Real-Time Non-Excessive Energy Amount – System charges after it has reviewed Xcel Electric's reply comments.
- The Department recommends that Xcel provide in reply comment the amounts of the new ramping products included in the FYE17 reporting period.
- The Department will make its overall recommendation regarding Xcel Electric's FYE17 ASM Reporting after it reviews Xcel Electric's reply comments.
- The Department concludes that MP's FYE17 ASM charges appear reasonable. As a result, the Department recommends that the Commission accept MP's ASM reporting.
- The Department concludes that OTP's FYE17 ASM charges appear reasonable. As a result, the Department recommends that the Commission accept OTP's ASM reporting.

/ja

Xcel's wind curtailment costs as a percentage of wind costs

%	Xcel
FYE06	3.88
FYE07	4.76
FYE08	8.32
FYE09	2.42
FYE10	1.58
FYE11	2.11
FYE12	1.86
FYE13	1.80
FYE14	9.37
FYE15	4.37
FYE16	3.79
FYE17	1.74
Min	1.58
Max	9.37

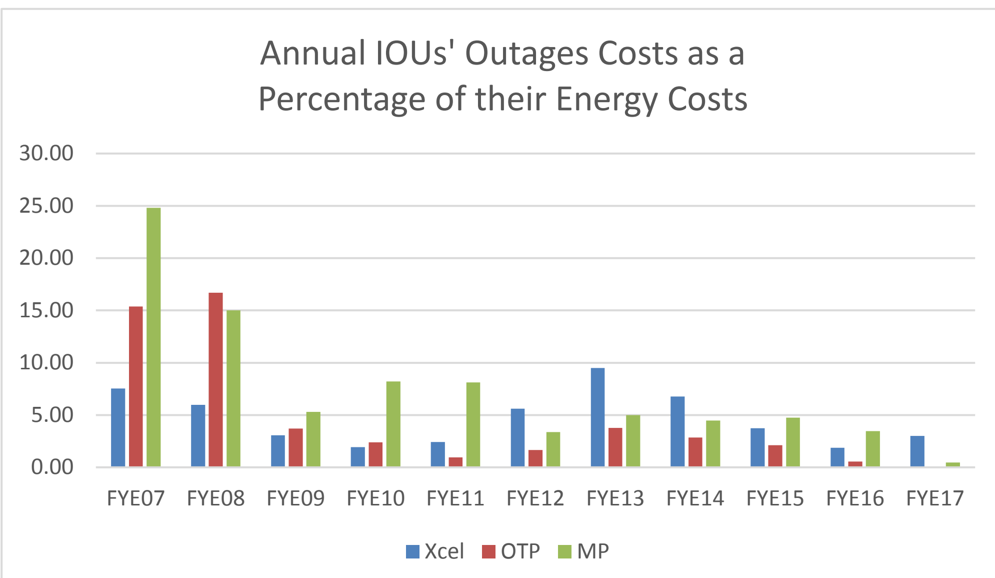
Source:
Xcel's monthly FCA input data emails.



Utilities Outages Costs in Percentage of Fuel and Purchased Power Costs

%	Xcel	OTP	MP
FYE07	7.55	15.38	24.80
FYE08	5.97	16.70	15.02
FYE09	3.06	3.70	5.29
FYE10	1.92	2.38	8.20
FYE11	2.41	0.95	8.12
FYE12	5.60	1.66	3.37
FYE13	9.50	3.77	4.99
FYE14	6.77	2.86	4.48
FYE15	3.75	2.12	4.74
FYE16	1.88	0.54	3.46
FYE17	3.00	0.00	0.45
Min	1.88	0.00	0.45
Max	9.50	16.70	24.80

Source: IOUs' monthly FCA input data emails.



Maintenance Expenses of Generation Plants

Actual Maintenance Expense

Xcel	2014	2015	2016	2017	2016-2017 Average
OTP	207,105,781	199,893,337	187,845,248	160,546,634	174,195,941
MP	16,587,034	14,646,839	13,573,426	12,540,306	13,056,866
	42,236,247	40,475,462	38,505,407	38,555,947	38,530,677

MP's data includes wind maintenance expenses when compared to previous DOC reported 2014-2016 data.

	Most Recent Rate Case	Test Year	Test Year Budgeted Maintenance Expense	2016-2017 Avg. Actual Maintenance Expense	Difference: Actual less Budgeted	Percentage Difference
Xcel	GR-15-826	2016	$ 184,709,427	$ 174,195,941	$ (10,513,486)	-5.7%
OTP	GR-15-1033	2016	$ 15,099,063	$ 13,056,866	$ (2,042,197)	-13.5%
MP	GR-16-664	2017	$ 42,468,677	$ 38,555,947	$ (3,938,000)	-9.3%

The average actual maintenance expense is based on the 2017 actual data for MP.

DEA	kWh Sales (a)	MN Energy Costs (b)	MN Recovery (c)	MN Energy Costs ($/kWh) (d)	MN Recovery ($/kWh) (e)
Jul-16	178,773,659	$ 18,981,949	$ 15,701,951	0.106	0.088
Aug-16	198,791,628	$ 18,305,334	$ 17,674,848	0.092	0.089
Sep-16	170,956,298	$ 10,868,862	$ 13,431,660	0.064	0.079
Oct-16	141,304,267	$ 9,306,568	$ 11,070,497	0.066	0.078
Nov-16	130,316,259	$ 9,615,581	$ 10,178,974	0.074	0.078
Dec-16	143,506,099	$ 12,657,724	$ 11,213,732	0.088	0.078
Jan-17	158,536,045	$ 12,488,107	$ 12,554,408	0.079	0.079
Feb-17	146,910,800	$ 11,008,874	$ 11,665,093	0.075	0.079
Mar-17	136,050,713	$ 10,066,345	$ 10,617,563	0.074	0.078
Apr-17	128,574,059	$ 9,107,299	$ 10,016,907	0.071	0.078
May-17	131,280,558	$ 10,517,249	$ 10,170,618	0.080	0.077
Jun-17	155,030,171	$ 16,786,682	$ 13,648,257	0.108	0.088
FYE17	1,820,030,556	149,710,574	147,944,508	0.082	0.081

Source (a): Dakota's AAA filing, Exhibit CII, page 1
Source (b): Dakota's AAA filing, Exhibit CII, page 1.
Source (c): Dakota's AAA filing, Exhibit CII, page 1.
(d) = (b)/(a)
(e) = (c)/(a)

MP	**kWh Retail & Firm Resale** (a)	**FCA Retail Sales** (b)	**System Costs** (c)
Jul-16	769,380,966	624,111,125	$16,155,525
Aug-16	776,746,706	632,394,048	$17,405,887
Sep-16	772,844,288	646,004,334	$14,375,542
Oct-16	797,884,168	643,012,781	$18,096,791
Nov-16	769,613,853	637,981,768	$15,179,645
Dec-16	818,767,539	661,349,842	$18,490,445
Jan-17	869,807,558	713,958,927	$18,316,085
Feb-17	808,568,668	674,122,567	$16,344,272
Mar-17	866,832,738	723,570,850	$18,010,194
Apr-17	821,561,651	693,797,462	$17,694,650
May-17	808,234,936	684,043,755	$15,783,082
Jun-17	792,013,491	668,388,119	$15,707,867
FYE17	9,672,256,562	8,002,735,578	$ 201,559,985

Source (a): MP's monthly FCAs
Source (b): MP's monthly FCAs.
Source (c): MP's monthly FCAs

Minnesota base cost ($/kWh): July 16 - June 17 0.01018

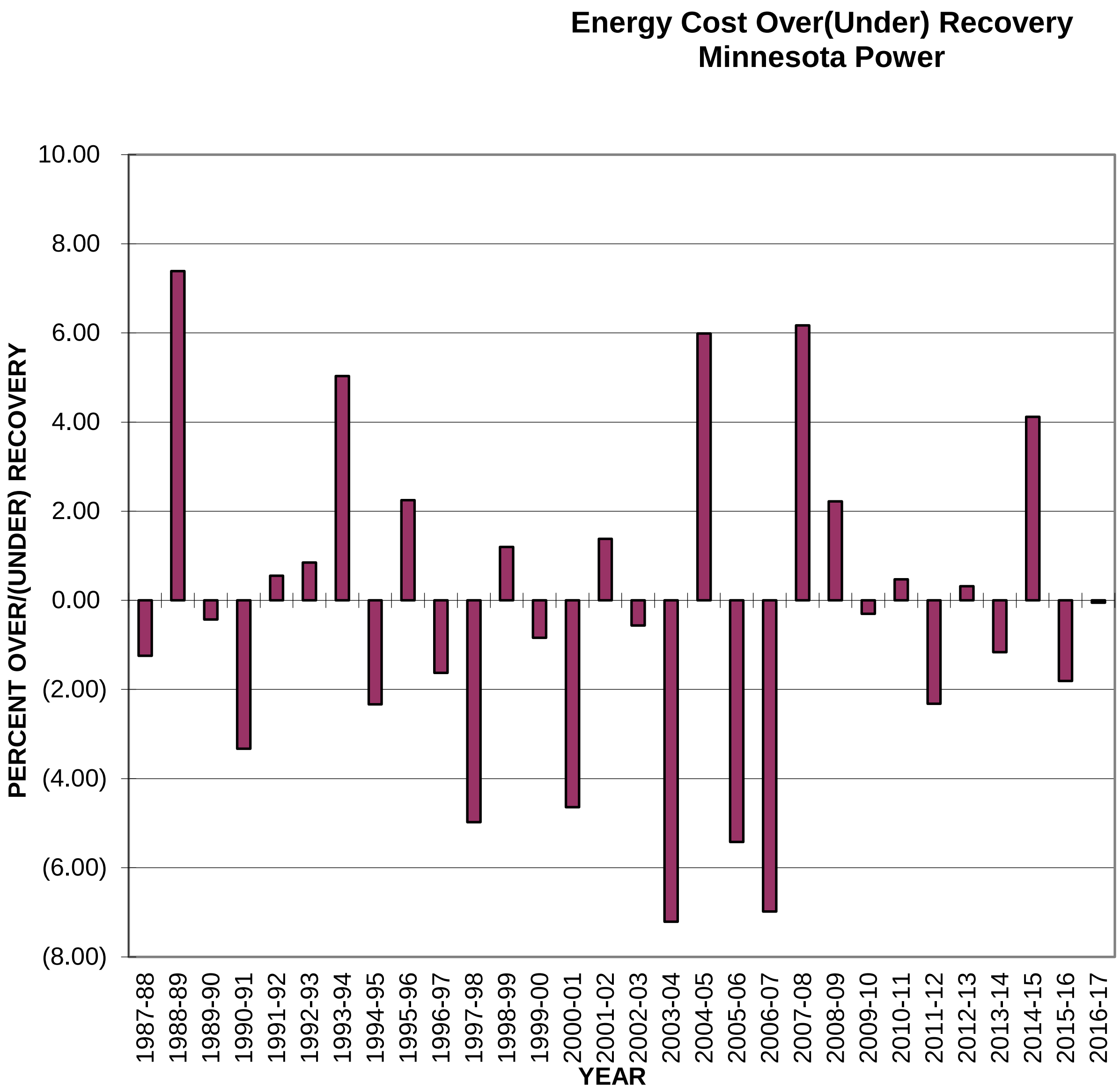
MP	FCA # 16 Recovery (d)	Old FCA # 16 Recovery (e)	Old FCA # 17 Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-16	5,633,822	$ -	-	$ 6,362,893	$ 11,996,714	$ 13,106,334	$ (1,109,619)	0.019	0.021
Aug-16	6,286,904	$ -	-	$ 6,450,210	$ 12,737,114	$ 14,171,951	$ (1,434,837)	0.020	0.022
Sep-16	6,731,855	$ -	-	$ 6,587,076	$ 13,318,932	$ 12,015,681	$ 1,303,251	0.021	0.019
Oct-16	7,405,794	$ -	-	$ 6,537,560	$ 13,943,354	$ 14,583,530	$ (640,176)	0.022	0.023
Nov-16	6,585,632	$ -	-	$ 6,488,805	$ 13,074,438	$ 12,581,000	$ 493,437	0.020	0.020
Dec-16	6,949,926	$ -	-	$ 6,742,199	$ 13,692,125	$ 14,933,279	$ (1,241,154)	0.021	0.023
Jan-17	7,925,710	$ -	-	$ 7,301,382	$ 15,227,091	$ 15,035,975	$ 191,116	0.021	0.021
Feb-17	7,462,092	$ -	-	$ 6,892,878	$ 14,354,970	$ 13,624,017	$ 730,953	0.021	0.020
Mar-17	8,406,608	$ -	-	$ 7,363,607	$ 15,770,215	$ 15,035,802	$ 734,413	0.022	0.021
Apr-17	7,270,016	$ -	-	$ 7,066,080	$ 14,336,096	$ 14,944,397	$ (608,301)	0.021	0.022
May-17	7,049,107	$ -	-	$ 6,945,382	$ 13,994,489	$ 13,359,375	$ 635,114	0.020	0.020
Jun-17	7,323,621	$ -	-	$ 6,791,889	$ 14,115,510	$ 13,254,136	$ 861,374	0.021	0.020
FYE17	$ 85,031,087	$ -	$ -	$ 81,529,962	$ 166,561,049	$ 166,645,477	$ (84,429)	0.021	0.0208

Source (d-g): Department's calculations based on data provided in MP's monthly FCAs.
(h) = SUM(d:g)
(i)=(b)*(c)/(a)
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Total Company Recovery, July 2016 - June 2017, By Month

Month	Minnesota Energy Costs	Minnesota Recovery	Over(Under) Recovery	Over(Under) Percentage
	(a)	(b)	(c)	(d)
July	$ 13,106,334	$11,996,714	($1,109,619)	(8.47%)
August	$ 14,171,951	$12,737,114	($1,434,837)	(10.12%)
September	$ 12,015,681	$13,318,932	$1,303,251	10.85%
October	$ 14,583,530	$13,943,354	($640,176)	(4.39%)
November	$ 12,581,000	$13,074,438	$493,437	3.92%
December	$ 14,933,279	$13,692,125	($1,241,154)	(8.31%)
January	$ 15,035,975	$15,227,091	$191,116	1.27%
February	$ 13,624,017	$14,354,970	$730,953	5.37%
March	$ 15,035,802	$15,770,215	$734,413	4.88%
April	$ 14,944,397	$14,336,096	($608,301)	(4.07%)
May	$ 13,359,375	$13,994,489	$635,114	4.75%
June	$ 13,254,136	$14,115,510	$861,374	6.50%
Total	**$ 166,645,477**	**$166,561,049**	**($84,429)**	**(0.05%)**

Source: Department's calculations.
(c) = (b) - (a)
(d)= (c)/(a)


Energy Cost Over(Under) Recovery
Minnesota Power
PERCENT OVER/(UNDER) RECOVERY
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
1987-88
1988-89
1989-90
1990-91
1991-92
1992-93
1993-94
1994-95
1995-96
1996-97
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1999-00
2000-01
2001-02
2002-03
2003-04
2004-05
2005-06
2006-07
2007-08
2008-09
2009-10
2010-11
2011-12
2012-13
2013-14
2014-15
2015-16
2016-17
YEAR

OTP	kWh Retail & Firm Resale (a)	Sales Subject to FCA (kWh) (b)	System Costs (c)
Jul-16	350,538,731	191,580,767	$ 7,781,629
Aug-16	379,347,773	202,108,094	$ 8,142,234
Sep-16	375,593,753	200,497,499	$ 7,351,614
Oct-16	335,616,423	178,922,553	$ 9,374,131
Nov-16	376,863,604	188,531,390	$ 9,566,172
Dec-16	435,529,060	213,128,312	$ 12,903,791
Jan-17	512,416,157	245,469,280	$ 12,832,491
Feb-17	480,824,815	230,220,722	$ 9,874,223
Mar-17	426,591,622	208,821,123	$ 10,839,809
Apr-17	408,658,500	203,028,030	$ 8,052,551
May-17	353,854,625	186,305,077	$ 9,833,135
Jun-17	358,156,520	190,433,342	$ 8,702,046
FYE17	4,793,991,583	2,439,046,189	$ 115,253,826

Source (a): OTP's July 31, 2017 compliance report approved by the Commission's September 27, 2017 Order in Docket No. E017/M-03-30.
Source (b): OTP's July 31, 2017 compliance report approved by the Commission's September 27, 2017 Order in Docket No. E017/M-03-30.
Source (c): OTP's July 31, 2017 compliance report approved by the Commission's September 27, 2017 Order in Docket No. E017/M-03-30.

MN Base Cost (($/kWh) 0.02464

OTP	Net FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over (Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-16	$ (1,027,733)	$ 4,720,550	$ 3,692,817	$ 3,959,071	$ (266,254)	0.019	0.021
Aug-16	$ (454,054)	$ 4,979,943	$ 4,525,889	$ 4,142,536	$ 383,353	0.022	0.020
Sep-16	$ (134,195)	$ 4,940,258	$ 4,806,063	$ 3,740,292	$ 1,065,772	0.024	0.019
Oct-16	$ (502,092)	$ 4,408,652	$ 3,906,560	$ 4,769,290	$ (862,731)	0.022	0.027
Nov-16	$ (773,742)	$ 4,645,413	$ 3,871,671	$ 4,866,995	$ (995,324)	0.021	0.026
Dec-16	$ (246,764)	$ 5,251,482	$ 5,004,718	$ 6,565,081	$ (1,560,363)	0.023	0.031
Jan-17	$ 461,285	$ 6,048,363	$ 6,509,648	$ 6,528,805	$ (19,157)	0.027	0.027
Feb-17	$ 693,712	$ 5,672,639	$ 6,366,351	$ 5,023,723	$ 1,342,628	0.028	0.022
Mar-17	$ 523,425	$ 5,145,352	$ 5,668,777	$ 5,514,986	$ 153,792	0.027	0.026
Apr-17	$ (360,061)	$ 5,002,611	$ 4,642,550	$ 4,096,908	$ 545,641	0.023	0.020
May-17	$ (335,745)	$ 4,590,557	$ 4,254,812	$ 5,002,819	$ (748,007)	0.023	0.027
Jun-17	$ (382,894)	$ 4,692,278	$ 4,309,384	$ 4,427,353	$ (117,969)	0.023	0.023
FYE17	$ (2,538,858)	$ 60,098,098	$ 57,559,240	$ 58,637,860	$ (1,078,619)		0.024

Source (f): OTP's July 31, 2017 compliance report approved by the Commission's September 27, 2017 Order in Docket No. E017/M-03-30.
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (c)*Total Revised Sales Subject to FCA/Net Total System Sales
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

(True-Up Calculation)

Xcel Electric	Prior Balance (a)	True Up Recovery (b)	FCA Recovery (c)	Base Cost Recovery (d)	Fuel Clause Revenues (e)	MN Energy Costs (f)	Saver's Switch True Up (g)	Solar Gardens Recovery (h)	FYE15 AAA PI Refund (i)	Balance (Cost-Revenues) (j)
Jul-16	$ (9,937,281)	$ (9,959,662)	$ (3,004,632)	$ 80,534,942	$ 67,570,648	$ 71,859,245	$ (234,626)			$ (5,883,310)
Aug-16	$ (6,335,857)	$ (6,617,763)	$ (3,451,940)	$ 81,161,722	$ 71,092,019	$ 74,316,437	$ (240,629)			$ (3,352,068)
Sep-16	$ (5,883,310)	$ (5,865,442)	$ (1,257,786)	$ 67,426,198	$ 60,302,969	$ 64,441,663	$ (140,541)			$ (1,885,157)
Oct-16	$ (3,352,068)	$ (3,286,789)	$ (3,053,749)	$ 63,946,260	$ 57,605,722	$ 59,447,351	$ -			$ (1,510,439)
Nov-16	$ (1,885,157)	$ (1,767,618)	$ 202,086	$ 60,186,136	$ 58,620,604	$ 58,800,850	$ -			$ (1,704,911)
Dec-16	$ (1,510,439)	$ (1,528,253)	$ (4,603,804)	$ 68,554,805	$ 62,422,747	$ 59,814,808	$ -			$ (4,118,379)
Jan-17	$ (1,704,911)	$ (1,688,415)	$ (816,634)	$ 68,402,427	$ 65,897,378	$ 61,675,154	$ -			$ (5,927,135)
Feb-17	$ (4,118,379)	$ (3,837,919)	$ (627,426)	$ 57,990,459	$ 53,525,114	$ 57,990,178	$ -	$ 517,709		$ 864,395
Mar-17	$ (5,927,135)	$ (5,962,931)	$ (2,268,486)	$ 64,684,534	$ 56,453,117	$ 62,585,205	$ -	$ 970,805		$ 1,175,758
Apr-17	$ 864,395	$ 838,154	$ 2,627,891	$ 56,803,757	$ 60,269,802	$ 56,307,423	$ -	$ 589,963		$ (2,508,021)
May-17	$ 1,175,758	$ 1,155,534	$ 3,417,042	$ 61,884,402	$ 66,456,978	$ 59,413,626	$ -	$ 1,302,631		$ (4,564,963)
Jun-17	$ (2,508,021)	$ (2,561,850)	$ 3,442,982	$ 70,987,877	$ 71,869,009	$ 64,735,689	$ 6,672	$ 1,314,177	$ (4,464,486)	$ (12,784,978)
FYE17		$ (41,082,954)	$ (9,394,457)	$ 802,563,518	$ 752,086,107	$ 751,387,629				

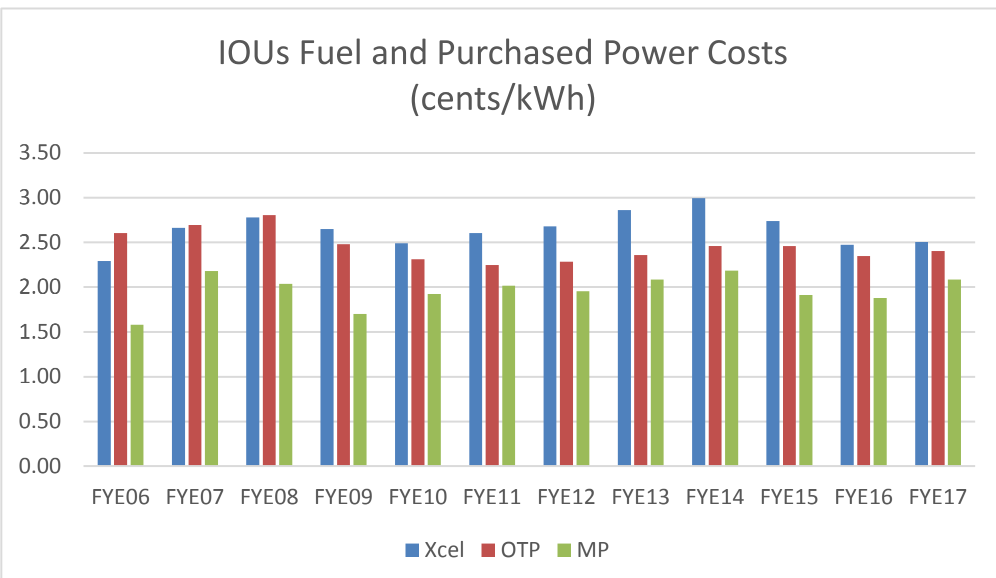
(a) = (h) with a two-month lag.
Source (b), (c), (d) & (f): Xcel's monthly FCA data with further Department calculations under the Department's review of the monthly FCAs.
(e) = (b) + (c) + (d)
Source (g-i): Xcel's monthly FCAs. More info on the Saver's Switch discount program is provided in
Xcel's May 7, 2007 Supplemental Information Compliance filing in Docket No. E002/GR-05-1428.
(j) = (a) - (e) + (f) + (g) + (h) + (i)

Note 1:
Xcel's FCA factor is the ratio of (system costs - intersystem sales - Windsource costs) by (system retail MWh, resale MWh and Windso MWh).
Minnesota costs are the product of the FCA factor by MN sales (MWh) subject to FCA factor (retail minus Windsource).
Xcel's FCA revenues are calculated on the basis of MN sales (MWh) subject to FCA factor.

Utilities Fuel and Purchased Power Costs in cents per kWh

Cents/kWh	Xcel	OTP	MP
FYE06	2.29	2.60	1.58
FYE07	2.66	2.69	2.18
FYE08	2.78	2.81	2.04
FYE09	2.65	2.48	1.70
FYE10	2.49	2.31	1.92
FYE11	2.60	2.24	2.02
FYE12	2.68	2.29	1.95
FYE13	2.86	2.36	2.09
FYE14	2.99	2.46	2.19
FYE15	2.74	2.46	1.91
FYE16	2.47	2.35	1.88
FYE17	2.51	2.40	2.08
Min	2.29	2.24	1.58
Max	2.99	2.81	2.19

Source: IOUs' monthly FCA input data emails.



Minnesota Electric Utilities' Average Residential Bills for 2016

Xcel Electric		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016 Monthly Av.**
Av. residential monthly kWh usage		711	587	566	477	535	707	846	843	593	530	536	691	635
(1) Number of customers		1,126,784	1,128,263	1,129,124	1,129,683	1,130,380	1,130,539	1,130,370	1,131,893	1,132,176	1,133,567	1,134,574	1,135,931	13,573,284
(1) Residential sales (MWh)		801,615	662,086	639,108	538,647	604,296	799,727	956,243	954,075	671,468	600,379	608,253	785,148	8,621,045
(2) Customer Charge		$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	
(2) Energy charge ($/kWh)														
Jan-May and Oct	0.0804	0.0804	0.0804	0.0804	0.0804	0.0804	0.0940	0.0940	0.0940	0.0940	0.0804			
June - Sep	0.0940													
Nov - Dec	0.0804											0.0804	0.0804	
En. Charge X kWh usage		$ 57.20	$ 47.18	$ 45.51	$ 38.34	$ 42.98	$ 66.46	$ 79.48	$ 79.19	$ 55.72	$ 42.58	$ 43.10	$ 55.57	
(2) Fuel Clause Adjustment ($/kWh)		0.02838	0.02628	0.02285	0.02432	0.02578	0.02410	0.02281	0.02390	0.02429	0.02476	0.02622	0.02430	
FCA X kWh usage		$ 20.19	$ 15.42	$ 12.93	$ 11.60	$ 13.78	$ 17.05	$ 19.30	$ 20.15	$ 14.41	$ 13.11	$ 14.06	$ 16.80	
CIP surcharge ($/kWh)														
(2) Jan-Sep 2015	$ 0.001386	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014	$ 0.0014				
(2) Oct-Dec 2015	$ 0.002164										$ 0.002164	$ 0.002164	$ 0.002164	
CIP surchrg. X customer's usage		$ 0.99	$ 0.81	$ 0.78	$ 0.66	$ 0.74	$ 0.98	$ 1.17	$ 1.17	$ 0.82	$ 1.15	$ 1.16	$ 1.50	
Total av. resid. monthly bill		$ 86.37	$ 71.42	$ 67.23	$ 58.59	$ 65.50	$ 92.49	$ 107.95	$ 108.50	$ 78.95	$ 64.84	$ 66.32	$ 81.86	$ 79.17
Av. Resid. energy charge + FCA ($/kWh)		10.88	10.67	10.33	10.47	10.62	11.81	11.68	11.79	11.82	10.52	10.66	10.47	10.97

(1) Source: Xcel Electric's 2016 Annual Jurisdictional Report, page Sales & Degree E-29, May 1, 2017 (Docket No. 17-4).
(2) Source: Xcel Electric's response to IR 11 in Docket No. E999/AA-17-492.

Minnesota Power		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016 Monthly Av.**
Av. residential monthly kWh usage		952	816	735	646	562	567	658	671	550	594	653	932	695
(1) Number of customers		121,601	121,333	121,486	121,605	121,744	122,493	122,047	121,823	122,080	121,928	121,881	122,041	1,462,062
(1) Residential sales (MWh)		115,765	99,007	89,251	78,550	68,375	69,512	80,362	81,747	67,194	72,478	79,540	113,681	1,015,465
(2) Customer Charge		$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	
(2) Energy charge ($/kWh)														
0 to 300 kWh	0.05098	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	$ 15.29	
301 to 500 kWh	0.06735	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	$ 13.40	
501 to 750 kWh	0.08168	$ 20.34	$ 20.34	$ 20.34	$ 11.92	$ 5.03	$ 5.51	$ 12.94	$ 13.97	$ 4.12	$ 7.71	$ 12.46	$ 20.34	
751 to 1000 kWh	0.08445	$ 16.98	$ 5.49										$ 15.33	
over 1000 kWh	0.08937													
Total monthly energy charge		$ 66.01	$ 54.52	$ 49.03	$ 40.62	$ 33.73	$ 34.21	$ 41.64	$ 42.67	$ 32.81	$ 36.41	$ 41.16	$ 64.36	
(2) Fuel Clause Adjustment ($/kWh)		0.00857	0.00690	0.00804	0.00880	0.00790	0.00792	0.00965	0.01062	0.01114	0.01235	0.01106	0.01123	
FCA X kWh usage		$ 8.16	$ 5.63	$ 5.91	$ 5.68	$ 4.44	$ 4.49	$ 6.35	$ 7.13	$ 6.13	$ 7.34	$ 7.22	$ 10.46	
(2) CIP surcharge Jan-June	$ 0.003961													
July-Dec	$ 0.006519													
CIP (CPA+CCRC) surcharge X customer's bill		$ 3.77	$ 3.23	$ 2.91	$ 2.56	$ 2.22	$ 2.25	$ 4.29	$ 4.37	$ 3.59	$ 3.87	$ 4.25	$ 6.07	
Total av. resid. monthly bill		$ 85.94	$ 71.39	$ 65.85	$ 56.86	$ 48.39	$ 48.95	$ 60.29	$ 62.17	$ 50.53	$ 55.63	$ 60.63	$ 88.90	$ 62.96
Av. Resid. energy charge + FCA ($/kWh)		7.79	7.37	7.48	7.17	6.80	6.82	7.29	7.42	7.08	7.36	7.41	8.03	7.33

(1) Source: MP's 2015 Annual Jurisdictional Report, page E-29 extra, May 01, 2017. (Docket 17-4)
(2) Source: MP's response to IR 11 in Docket No. E999/AA-17-492.

Minnesota Electric Utilities' Average Residential Bills for 2016

Otter Tail Power	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016 Monthly Av.**
Av. residential monthly kWh usage	1,349	1,271	1,110	926	719	718	771	845	773	648	758	1,073	912
(1) Number of customers	47,679	47,744	47,771	47,737	47,923	48,878	48,923	48,980	48,959	48,448	47,815	47,871	578,728
(1) Residential Sales (MWh)	64,318	60,676	53,035	44,214	34,466	35,073	37,728	41,396	37,860	31,407	36,252	51,382	527,807
(2) Customer Charge	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	$ 8.50	
(2) Energy charge ($/kWh)	0.08192	0.08192	0.08192	0.08340	0.08340	0.08124	0.08124	0.08124	0.08124	0.0834	0.0834	0.0834	
Total monthly energy charge	$ 110.51	$ 104.11	$ 90.95	$ 77.25	$ 59.98	$ 58.29	$ 62.65	$ 68.66	$ 62.82	$ 54.07	$ 63.23	$ 89.52	
(2) Fuel Clause Adjustment ($/kWh)	(0.00030)	0.00098	0.00072	(0.00336)	(0.00366)	(0.00410)	(0.00599)	(0.00281)	(0.00095)	(0.00312)	(0.00442)	(0.00142)	
FCA X kWh	$ (0.40)	$ 1.25	$ 0.80	$ (3.11)	$ (2.63)	$ (2.94)	$ (4.62)	$ (2.37)	$ (0.73)	$ (2.02)	$ (3.35)	$ (1.52)	
(2) CIP surcharge	0.00287	0.00287	0.00287	0.00287	0.00287	0.00287	0.00287	0.00287	0.00287	0.00275	0.00275	0.00275	
CIP surchrg. X customer's bill	$ 0.34	$ 0.33	$ 0.29	$ 0.24	$ 0.19	$ 0.18	$ 0.19	$ 0.21	$ 0.20	$ 0.17	$ 0.19	$ 0.27	
Total av. resid. monthly bill	$ 118.94	$ 114.18	$ 100.53	$ 82.87	$ 66.04	$ 64.04	$ 66.72	$ 75.00	$ 70.79	$ 60.71	$ 68.57	$ 96.76	$ 82.10
Av. Resid. energy charge + FCA ($/kWh)	8.16	8.29	8.26	8.00	7.97	7.71	7.53	7.84	8.03	8.03	7.90	8.20	7.99

(1) Source: OTP's 2015 Annual Jurisdictional Report, page E-29, Apr 28, 2017. (Docket 17-4)
(2) Source: OTP's response to IR 11 in Docket No. E999/AA-17-492.

Dakota Electric Association	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016 Monthly Av.**
(1) Av. residential monthly kWh usage	711	587	566	477	535	707	846	843	593	530	536	691	635
(2) Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	
(2) Energy Charge ($/kWh)	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.13080	$ 0.13080	$ 0.13080	$ 0.11680	$ 0.11680	$ 0.11680	$ 0.11680	
En. Chrg. X kWh usage	$ 83.09	$ 68.54	$ 66.11	$ 55.69	$ 62.44	$ 92.53	$ 110.65	$ 110.25	$ 69.27	$ 61.86	$ 62.62	$ 80.73	
(2) Power Cost Adjustment ($/k\	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	
Power Cost Adj. X kWh	$ 2.13	$ 1.76	$ 1.70	$ 1.43	$ 1.60	$ 2.12	$ 2.54	$ 2.53	$ 1.78	$ 1.59	$ 1.61	$ 2.07	
(2) CIP & Property tax surcharge ($/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	
DSM surchrg. X customer's bill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total av. resid. monthly bill	$ 94.23	$ 79.30	$ 76.81	$ 66.12	$ 73.04	$ 103.65	$ 122.19	$ 121.78	$ 80.05	$ 72.45	$ 73.23	$ 91.80	$ 87.89
Av. Resid. energy charge + FCA ($/kWh)	11.98	11.98	11.98	11.98	11.98	13.38	13.38	13.38	11.98	11.98	11.98	11.98	12.33

(1) Source: Xcel's average residential kWh usage figures were used as a proxy, because Dakota does not file a detailed MN Annual Jurisdictional Report.
(2) Source: Dakota's response to IR 11 in Docket No. E999/AA-17-492

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☒ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☐ **Public Document**

Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 21
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:

Topic: MISO Day 2 Net Invoice
Reference(s): Initial Filing, Part J, Section 5, Schedule 7, Page 9 of 13

For the month of March 2017, please provide copies of the MISO bills along with a summary/reconciliation sheet totaling the net invoice amount of ($6,069,924.98) for total MISO Day 2 charges as shown on the above referenced schedule.

Response:

See Attachment A for a reconciliation spreadsheet totaling the net invoice amount for this period. See Attachment B for copies of the MISO invoices for March 2017.

Please note that portions of Attachment B have been designated as Not Public pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information designated as Not Public derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Preparer: Matthew Brand
Title: Senior RTO/ISO Accountant
Department: Market Operations Accounts
Telephone: 303-571-7744
Date: September 24, 2018

GL YYYY-MM 2017-03

Row Labels	Type	Description	Account	Level 1 SA	Level 2 ZA	Level 2 Reversal ZD	Level 3 ZA	Level 3 Reversal ZD	Cong/Loss s105 SA	Cong/Loss s105 Reversal ZD	Cong/Loss s14 ZA	Cong/Loss s14 Reversal ZD	Cong/Loss s7 ZA	Cong/Loss s7 Reversal ZD	Sch 24 Resett 2006-2016 SA	Grand Total
	NSPP:			Column Labels												
INVOICED	ADMIN FEES	DA_ADMIN	5066201	574,778.37	150,020.48	(60,372.61)	145,067.90	(116,197.23)								693,296.91
		DA_SCHD_24_ALC	5066201	91,256.30	21,615.92	(11,534.39)	20,886.62	(22,250.36)							337,762.44	437,736.53
		FTR_ADMIN	5066201	34,205.04	7,671.36	(5,619.84)	7,671.36	(9,641.20)								34,286.72
		RT_ADMIN	5066201	43,117.01	10,275.62	(4,638.01)	9,173.92	(9,396.31)								48,532.23
		RT_SCHD_24_ALC	5066201	7,003.61	1,508.11	(904.91)	1,348.49	(1,833.08)								7,122.22
	ADMIN FEES Total			750,360.33	191,091.49	(83,069.76)	184,148.29	(159,318.18)							337,762.44	1,220,974.61
	ASSET ENERGY	DA_ASSET_EN	5066016	(2,650,237.87)	1,044,132.09	(260,330.46)	686,801.50	691,591.99	(6,431,151.48)	3,215,575.75	(7,799,608.49)	8,253,901.59	(3,531,363.85)	2,794,010.10		(3,986,679.13)
		DA_ASSET_EN_CG	5066016						1,922,822.38	(961,411.19)	1,360,099.87	(2,073,195.80)	776,088.63	(259,745.68)		764,658.21
		DA_ASSET_EN_LS	5066016						4,508,329.08	(2,254,164.54)	6,439,508.59	(6,180,705.75)	2,755,275.22	(2,534,264.41)		2,733,978.19
		RT_ASM_EXE	5066016	(1,520.32)	6,083.19	(1,935.40)	38.11									2,665.58
		RT_ASM_NXE	5066016	(575,504.57)	(339,306.73)	133,591.21	(161,322.73)	355,358.75	(54,009.82)	(73,933.47)	120,683.73	61,634.80	(53,561.26)	(145,577.64)		(731,947.73)
		RT_ASM_NXE_CG	5066016						(107,157.91)	119,152.39	(129,280.48)	57,418.15	(7,740.48)	111,384.89		43,776.56
		RT_ASM_NXE_LS	5066016						161,167.73	(45,218.92)	8,596.75	(119,052.96)	61,301.73	34,192.75		100,987.08
		RT_ASSET_EN	5066016	(359,178.52)	23,504.49	(45,764.81)	(262,938.38)	358,042.86	118,885.10	(40,598.88)	(191,811.07)	3,174.39	(121,441.70)	154,064.33		(364,062.19)
		RT_ASSET_EN_CG	5066016						(95,699.17)	35,302.77	125,826.97	11,018.86	89,444.66	(102,821.83)		63,072.26
		RT_ASSET_EN_LS	5066016						(23,185.91)	5,296.09	65,984.12	(14,193.27)	31,997.05	(51,242.51)		14,655.57
	ASSET ENERGY Total			(3,586,441.28)	734,413.04	(174,439.46)	262,578.50	1,404,993.60	(0.00)	0.00	(0.01)	0.01	0.00	(0.00)		(1,358,895.60)
	NON-ASSET ENERGY	DA_FIN_CG	5066016	(1,452.34)	492.86	1,689.84	260.26	1,519.26								2,509.88
		DA_FIN_LS	5066016	134.57	(265.35)	90.59	(30.62)	(274.91)								(345.72)
		DA_GFACO_RBT_CG	5066016	1,452.34	(492.86)	(1,689.84)	(260.26)	(1,519.26)								(2,509.88)
		DA_GFACO_RBT_LS	5066016	(134.57)	265.35	(90.59)	30.62	274.91								345.72
		DA_NASSET_EN	5066016	(4,985,920.46)	(1,285,014.01)	513,605.65	(1,507,672.49)	1,163,547.74	(3,244,277.98)	1,622,138.99	(2,366,134.81)	2,653,728.58	(2,082,955.66)	1,333,090.77		(8,185,863.68)
		DA_NASSET_EN_CG	5066016						1,838,335.48	(919,167.74)	1,245,214.98	(1,445,155.96)	1,280,608.74	(718,406.43)		1,281,429.07
		DA_NASSET_EN_LS	5066016						1,405,942.50	(702,971.25)	1,120,919.84	(1,208,572.63)	802,346.92	(614,684.34)		802,981.04
		RT_NASSET_EN	5066016	75,760.48	8,554.54			(15,267.39)	(3,161.70)	1,580.85	60.66	1,580.85	1,348.48	(55.02)		70,401.75
		RT_NASSET_EN_CG	5066016						2,286.90	(1,143.45)	198.07	(1,143.45)	2,178.12	(220.88)		2,155.31
		RT_NASSET_EN_LS	5066016						874.80	(437.40)	(258.73)	(437.40)	(3,526.60)	275.90		(3,509.43)
	NON-ASSET ENERGY Total			(4,910,159.98)	(1,276,459.47)	513,605.65	(1,507,672.49)	1,148,280.35	0.00	(0.00)	0.01	(0.01)	0.00	-		(6,032,405.94)
	ASM GEN	DA_ASM_REG	5066016	(146,272.82)	(80,863.35)	20,050.06	(67,524.98)	25,144.69								(249,466.40)
		DA_ASM_SPIN	5066016	(143,650.23)	(49,007.56)	21,442.59	(42,284.40)	28,534.42								(184,965.18)
		DA_ASM_SUPP	5066016	(43,687.20)	(13,088.00)	3,523.20	(12,396.88)	6,794.00								(58,854.88)
		RT_ASM_NRGA	5066016	(5,754.23)	(943.24)	(121.39)	(1,485.54)	621.30								(7,683.10)
		RT_ASM_REG	5066016	(1,651.36)	31,889.56	(4,454.86)	5,267.41	(1,497.05)								29,553.70
		RT_ASM_SPIN	5066016	(7,970.42)	(2,000.16)	(3,458.06)	(2,093.59)	3,624.38								(11,897.85)
		RT_ASM_SUPP	5066016	502.63	1,083.10		2,129.52	(20.89)								3,694.36
		RT_RC_AMT	5066016	(512.38)	(173.93)	(15.57)	(120.79)									(822.67)
		DA_RC_AMT	5066016	(2,466.60)	(2,007.91)	294.40										(4,180.11)
	ASM GEN Total			(351,462.61)	(115,111.49)	37,260.37	(118,509.25)	63,200.85								(484,622.13)
	ASM LOAD	RT_ASM_REG_DIST	5066016	119,701.89	36,280.59	(17,723.36)	28,172.46	(35,635.60)								130,795.98
		RT_ASM_SPIN_DIST	5066016	117,947.90	33,621.32	(12,679.61)	31,560.85	(23,125.34)								147,325.12
		RT_ASM_SUPP_DIST	5066016	44,835.30	11,074.97	(4,258.54)	11,425.18	(7,474.65)								55,602.26
	ASM LOAD Total			282,485.09	80,976.88	(34,661.51)	71,158.49	(66,235.59)								333,723.36
	MWP REVENUE	DA_RSG_MWP	5066016	(63,695.19)	(19,930.30)	3,011.90	(22,139.80)	22,660.79								(80,092.60)
		RT_PV_MWP	5066016	(118,283.39)	(22,373.53)	12,967.79	(24,780.70)	31,176.82								(121,293.01)
		RT_RSG_MWP	5066016	(46,081.27)	(4,788.73)											(50,870.00)
	MWP REVENUE Total			(228,059.85)	(47,092.56)	15,979.69	(46,920.50)	53,837.61								(252,255.61)
	RSG COST	DA_RSG_DIST	5066016	71,539.29	13,579.91	(4,184.62)	76,158.69	(5,872.91)								151,220.36
		RT_RSG_DIST1	5066016	82,462.20	24,112.39	(4,470.67)	18,850.41	(4,431.26)								116,523.07
	RSG COST Total			154,001.49	37,692.30	(8,655.29)	95,009.10	(10,304.17)								267,743.43
	FTR	FTR_ARR_ARR_TXN	5066016	(1,792,492.43)												(1,792,492.43)
		FTR_ARR_FTR_TXN	5066016	1,791,598.49												1,791,598.49
		FTR_ARR_INF_UPL	5066016	78,210.74	(18.77)											78,191.97
		FTR_ARR_STG2_DIST	5066016	(200,888.25)	2,017.42											(198,870.83)
		FTR_FFG	5066016	39,465.60	(23,793.19)	16,545.64	143,747.94	(101,674.14)								74,291.85
		FTR_GUL	5066016	(39,465.60)	23,793.19	(16,545.64)	(143,949.01)	102,441.14								(73,725.92)
		FTR_HR_ALC	5066016	(834,095.00)	(170,534.22)	172,390.34	(982.73)	162,370.26								(670,851.35)
		FTR_MN_ALC	5066016	(96,135.25)			(148,166.40)	125,989.71								(118,311.94)
		FTR_MO_TXN	5066016	168,156.77												168,156.77
	FTR Total			(885,644.93)	(168,535.57)	172,390.34	(149,350.20)	289,126.97								(742,013.39)
	PENALTY CHARGES	RT_ASM_EXE_DFE_DEP	5066016	92,702.64	22,262.43	(9,662.69)	12,081.47	(8,953.24)								108,430.61
		RT_ASM_CRDFC	5066016	4,041.87												4,041.87
	PENALTY CHARGES Total			96,744.51	22,262.43	(9,662.69)	12,081.47	(8,953.24)								112,472.48
	UPLIFT CHARGES	RT_LOSS_DIST	5066016	(597,764.92)	(129,641.76)	94,355.88	(83,708.41)	137,244.51								(579,514.70)
		RT_MISC	5066016	60,391.40	762,694.50										(337,762.44)	485,323.46
		RT_NI_DIST	5066016	203,918.73	(9,305.29)	(4,132.15)	29,961.50	(7,164.39)								213,278.40
		RT_RAA	5066016	(50,716.68)	(12,679.17)	7,245.24	(12,679.17)	12,679.17								(56,150.61)
		RT_RNU	5066016	322,379.60	202,299.33	18,768.27	116,846.01	(342,086.40)								318,206.81
		RT_DRR_UPL	5066016	242.98	68.67	0.21										311.86
	UPLIFT CHARGES Total			(61,548.89)	813,436.28	116,237.45	50,419.93	(199,327.11)							(337,762.44)	381,455.22
	TRANS/BA REVENUE	RT_MVP_DIST	5066016	(29,854.25)	(162.99)		(26,015.53)	30,137.04								(25,895.73)
		RT_SCHD_24_DIST	5066201	(100,392.02)	(25,467.31)	12,777.43	(24,718.32)	24,649.74								(113,150.48)
	TRANS/BA REVENUE Total			(130,246.27)	(25,630.30)	12,777.43	(50,733.85)	54,786.78								(139,046.21)
INVOICED Total				(8,869,972.39)	247,043.03	557,762.22	(1,197,790.51)	2,570,087.87	(0.00)	(0.00)	(0.00)	0.00	0.00	(0.00)	-	(6,692,869.78)
																$ (6,692,869.78) MISO Day 2 charges plus ASN
															Check	-
	NSPT:															
	ADMIN FEES	DA_ADMIN	5066201	857.76												
		DA_SCHD_24_ALC	5066201	138.72												
	NON-ASSET ENERGY	DA_NASSET_EN	5066016	225,288.66												
	UPLIFT CHARGES	RT_NI_DIST	5066016	278.89												
INVOICED Total				226,564.03												
			MISO Invoice Total:	(8,643,408.36)	Ties to Invoice total for March 2017											

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Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 22
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:

Topic: MISO Day 2 and Ancillary Services Market (ASM) Allocations between Retail and Asset-Based Wholesale
Reference(s): Initial Filing, Part J, Section 5, Schedule 7

Please explain if Xcel changed any of the allocation methods used to allocate MISO Day 2 and ASM charges between retail and asset-based wholesale during the FYE17 reporting period when compared to the FYE16 reporting period. If so, please provide the charge type, the change in allocation method, and the impact it had on the dollar amounts allocated between retail and asset-based wholesale for FYE17.

Response:

The allocation method used to allocate MISO Day 2 and ASM charges between retail and asset-based wholesale did not change from the FYE 16 reporting period to the FYE 17 reporting period.

Preparer: Bill Olson
Title: Manager Market Operations Accounting
Department: Utility Accounting
Telephone: 303-571-7822
Date: September 24, 2018

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Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 23
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:

Topic: Asset-Based Margins
Reference(s): Initial Filing, Part J, Section 5, Schedule 7, Page 9 of 13

Please provide support to show that the ($14,094,205) in MISO Day 2 asset-based charges for March 2017 was included in Xcel's asset-based margin calculation and credited to ratepayers via the fuel clause adjustment.

Response:
The $14.094 million reported in the AAA report for March 2017 represents a portion of the total asset based revenues. The question above indicates it is a charge; however, it is a negative net cost and therefore is revenue. Cost of Goods Sold expenses are deducted from the total asset based revenue to calculate the total asset based margin. The Minnesota jurisdictional portion credited to Minnesota ratepayers in the May 2017 fuel clause adjustment was $1,860,792.

Please see below for additional detail:

Minnesota Asset Based Margin Sharing	**$- millions**
(1) MISO Day 2 and ASM Intersystem Asset Based Revenue	$14.0
(2) Non-MISO Asset Based Revenue	$1.3
(3) Total Asset Based Revenue (1)+(2)	$15.3
(4) Less: Cost of Goods Sold	$11.6
(5) NSP System Asset Based Margins (3)–(4)	$3.7
(6) Less: Ratepayer Sharing (*)	$2.3
(7) Less: Other Jurisdictions Specific Adjustments	$0.8
(8) Other Jurisdictions' Pass-Through/Company Retention	$0.6
* **Ratepayer Sharing Detail**	
Minnesota Jurisdiction	$2,665,023
Less: Jurisdiction Specific Adjustments	$804,231
Minnesota Net Portion	**$1,860,792**
Other NSP Jurisdictions	$411,357
Total NSP Ratepayers Sharing	$2,272,149

Preparer: Allison Johnson
Title: Principal Financial Consultant
Department: NSP Commercial Accounting
Telephone: 303-571-6967
Date: September 24, 2018

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Xcel Energy

Docket No.:	E999/AA-17-492		
Response To:	MN Department of Commerce	Information Request No.	24
Requestor:	Mark Johnson		
Date Received:	September 14, 2018		

Question:

Topic: Asset-Based Margins
Reference(s): N/A

Please provide the amount of asset-based margins returned to ratepayers via the fuel clause for the FYE17 reporting period.

Response:
Approximately $18.3 million of realized Minnesota jurisdictional share of asset-based margins was returned to ratepayers via the fuel cost for the FYE17 reporting period. This information is included in Attachment A.

Preparer:	John Chow / James Schroeder
Title:	Pricing Consultant / Accounting - Financial Consultant
Department:	NSPM Regulatory / NSP Utility Accounting
Telephone:	612-330-7588 / 612-330-6208
Date:	September 24, 2018

Northern States Power Company
State of Minnesota - Electric Utility
Minnesota Asset Based Margin Sharing - 2017 AAA Period

Month Margin Realized **Fuel Clause Month**	**Jul-16** **Sep-16**	**Aug-16** **Oct-16**	**Sep-16** **Nov-16**	**Oct-16** **Dec-16**	**Nov-16** **Jan-17**	**Dec-16** **Feb-17**	**Jan-17** **Mar-17**	**Feb-17** **Apr-17**	**Mar-17** **May-17**	**Apr-17** **Jun-17**	**May-17** **Jul-17**	**Jun-17** **Aug-17**	**FYE 2017** **Total**
Monthly Refund & True-up													
Monthly Asset Based Margin from G/L	(304,668)	383,839	(875,645)	(1,395,509)	(1,586,515)	(3,126,329)	(2,857,491)	(3,285,057)	(1,858,045)	(382,419)	(2,397,854)	(653,622)	(18,339,315)
Month True-up	(24,434)	5,633	(1,186)	7,160	(54,136)	18,517	(11,301)	(206,938)	16,618	(102,263)	(74,795)	9,966	(417,158)
Total to be Refunded	(329,102)	389,472	(876,831)	(1,388,349)	(1,640,651)	(3,107,812)	(2,868,792)	(3,491,995)	(1,841,427)	(484,682)	(2,472,649)	(643,655)	(18,756,472)
Sales													
Forecasted Calendar Month Sales	2,535,377	2,444,689	2,405,113	2,539,342	2,589,519	2,333,162	2,410,441	2,196,398	2,361,253	2,603,780	2,973,914	2,944,969	
Less: Windsource Forecast	(12,136)	(11,555)	(10,337)	(11,399)	(12,611)	(11,526)	(11,648)	(10,783)	(11,586)	(10,564)	(13,159)	(14,069)	
Forecasted Sales	2,523,241	2,433,134	2,394,776	2,527,943	2,576,908	2,321,636	2,398,793	2,185,615	2,349,667	2,593,216	2,960,755	2,930,900	
Actual Calendar Month Sales	2,527,118	2,401,420	2,258,691	2,574,683	2,574,622	2,180,164	2,427,018	2,134,119	2,267,790	2,662,673	2,928,623	2,673,790	
Less: Windsource Actual	(12,812)	(13,017)	(11,811)	(13,020)	(15,487)	(13,117)	(14,327)	(12,513)	(13,570)	(16,079)	(16,693)	(20,977)	
Actual Sales	2,514,306	2,388,403	2,246,880	2,561,663	2,559,135	2,167,047	2,412,691	2,121,606	2,254,220	2,646,594	2,911,930	2,652,813	
Monthly Refund Factor	(0.012)	0.016	(0.037)	(0.055)	(0.062)	(0.135)	(0.119)	(0.150)	(0.079)	(0.015)	(0.081)	(0.022)	
Monthly True-up Refund Factor	(0.001)	0.000	(0.000)	0.000	(0.002)	0.001	(0.000)	(0.009)	0.001	(0.004)	(0.003)	0.000	
Total Refund Factor	(0.013)	0.016	(0.037)	(0.055)	(0.064)	(0.134)	(0.120)	(0.160)	(0.078)	(0.019)	(0.084)	(0.022)	
True-up Calculation													
Expected Refund	(329,101.68)	389,471.88	(876,831.04)	(1,388,348.53)	(1,640,651.14)	(3,107,812.15)	(2,868,791.57)	(3,491,994.87)	(1,841,427.10)	(484,681.94)	(2,472,648.96)	(643,655.33)	
Actual Refund	(327,915.79)	382,311.67	(822,695.11)	(1,406,865.32)	(1,629,350.07)	(2,900,874.13)	(2,885,409.55)	(3,389,732.34)	(1,766,632.21)	(494,648.42)	(2,431,869.22)	(582,584.26)	(18,256,265)
(Under)/Over Refunded Amount	(1,185.89)	7,160.21	(54,135.93)	18,516.79	(11,301.07)	(206,938.02)	16,617.98	(102,262.53)	(74,794.89)	9,966.48	(40,779.74)	(61,071.07)	
Allocation Factors													
Residential	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	1.0185	
C&I Non-Demand	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	1.0493	
C&I Demand	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	1.0028	
C&I Demand On Peak	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	1.2732	
C&I Demand Off Peak	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	0.7987	
Street Lighting	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	0.7446	
Refund Factor													
Residential	(0.013)	0.016	(0.037)	(0.056)	(0.065)	(0.136)	(0.122)	(0.163)	(0.080)	(0.019)	(0.085)	(0.022)	
C&I Non-Demand	(0.014)	0.017	(0.038)	(0.058)	(0.067)	(0.140)	(0.125)	(0.168)	(0.082)	(0.020)	(0.088)	(0.023)	
C&I Demand	(0.013)	0.016	(0.037)	(0.055)	(0.064)	(0.134)	(0.120)	(0.160)	(0.079)	(0.019)	(0.084)	(0.022)	
C&I Demand On Peak	(0.017)	0.020	(0.047)	(0.070)	(0.081)	(0.170)	(0.152)	(0.203)	(0.100)	(0.024)	(0.106)	(0.028)	
C&I Demand Off Peak	(0.010)	0.013	(0.029)	(0.044)	(0.051)	(0.107)	(0.096)	(0.128)	(0.063)	(0.015)	(0.067)	(0.018)	
Street Lighting	(0.010)	0.012	(0.027)	(0.041)	(0.047)	(0.100)	(0.089)	(0.119)	(0.058)	(0.014)	(0.062)	(0.016)	

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Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 25
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:
Topic: MISO Day 2; 1a Day Ahead Asset Energy
Reference(s): Part J, Section 5, Schedule 7, Page 13 of 13 (16-523)
Part J, Section 5, Schedule 7, Page 13 of 13 (17-492)

Please explain why the above referenced schedules show that the annual MWh and net charges assigned to Retail for 1a Day Ahead Asset Energy increased significantly from 3,113,067 MWh and $93,607,099 in 16-523 to 4,803,192 MWh and $148,633,541 in 17-492.

Response:
Hours where the Company made net purchases increased by 1,690,124 MWh, these amounts are assigned to Retail. Hours where the Company made net sales increased by 2,390,923 MWh, these amounts are assigned to Asset Based. For Day Ahead Asset Energy in total, the Company switched year over year from purchasing 60,843 MWh to selling 639,956 MWh.

The increase in total sales is partially related to Day Ahead load bids remaining constant combined with a significant increase in Day Ahead awards to low-cost wind generation as three new resources were offered to the market.

The assignment between Retail purchases and Asset Based sales is directly related to the MISO market assigning the lowest cost generation currently available to serve load where the sum of the Company's hourly resource awards are less than or greater than the Company's hourly load obligation.

Preparer: Matt Schmidt
Title: Sr. Market Operation Financial Analyst
Department: Market Operation Accounting
Telephone: 303-571-7519
Date: September 24, 2018

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Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 26
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:

Topic: MISO Day 2; 28 Financial Transmission Rights Hourly Allocation
Reference(s): Part J, Section 5, Schedule 7, Page 13 of 13 (16-523)
Part J, Section 5, Schedule 7, Page 13 of 13 (17-492)

Please explain why the above referenced schedules show that net charges for Financial Transmission Rights Hourly Allocation increased significantly from ($21,996,610) in 16-523 to ($43,532,994) in 17-492.

Response:
The increase of $21,536,384 in Financial Transmission Rights Hourly Allocation revenue is primarily related to a transmission outage which caused strong congestion for several base load units between July and August of 2016. Related congestion cost of $19 million was offset by $21 million in related FTR revenue for a net benefit to customers of $2 million.

Preparer: Matt Schmidt
Title: Sr. Market Operation Financial Analyst
Department: Market Operation Accounting
Telephone: 303-571-7519
Date: September 24, 2018

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 27
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:
Topic: MISO Day 2; 6 Day Ahead Congestion Rebate on Carve Out - Grandfathered
Reference(s): Part J, Section 5, Schedule 7, Page 13 of 13 (16-523)
Part J, Section 5, Schedule 7, Page 13 of 13 (17-492)

Please explain why the above referenced schedules show that net charges for Day Ahead Congestion Rebate on Carve Out – Grandfathered increased significantly from $22,471 in 16-523 to $100,321 in 17-492.

Response:
Day Ahead Congestion Rebate on Carve Out - Grandfathered represents a rebate of congestion paid on financial schedules considered to be grandfathered agreements. Grandfathered agreements are exempt from paying congestion cost. Congestion costs can be a credit or charge depending upon current network topology which changes hourly in the Day Ahead Market. The charge of $100,321 in Docket No. E999/AA-17-492 has an offsetting value of ($100,321) on the Day Ahead Financial Bilateral Transaction Congestion line.

Preparer: Matt Schmidt
Title: Sr. Market Operation Financial Analyst
Department: Market Operation Accounting
Telephone: 303-571-7519
Date: September 24, 2018

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E999/AA-17-492
Response To: MN Department of Commerce Information Request No. 28
Requestor: Mark Johnson
Date Received: September 14, 2018

Question:
Topic: MISO Day 2; 7 Day Ahead Loss Rebate on Carve Out - Grandfathered
Reference(s): Part J, Section 5, Schedule 7, Page 13 of 13 (16-523)
Part J, Section 5, Schedule 7, Page 13 of 13 (17-492)

Please explain why the above referenced schedules show that Net Charges for Day Ahead Loss Rebate on Carve Out – Grandfathered changed from ($10,562) in 16-523 to $16,827 in 17-492.

Response:
Day Ahead Loss Rebate on Carve Out - Grandfathered represents a rebate of Loss paid on financial schedules considered to be grandfathered agreements. Grandfathered agreements are exempt from paying Loss cost. Loss costs can be a credit or charge depending upon current network topology which changes hourly in the Day Ahead Market. The charge of $16,827 in Docket No. E999/AA-17-492 has an offsetting value of ($16,827) on the Day Ahead Financial Bilateral Transaction Loss line.

Preparer: Matt Schmidt
Title: Sr. Market Operation Financial Analyst
Department: Market Operation Accounting
Telephone: 303-571-7519
Date: September 24, 2018

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E999/AA-17-492		
Response To:	MN Department of Commerce	Information Request No.	29
Requestor:	Mark Johnson		
Date Received:	September 14, 2018		

Question:

Topic: ASM; 8a Real Time Non Excessive Energy Amount - System
Reference(s): Part J, Section 5, Schedule 8, Page 1 of 12 (16-523)
Part J, Section 5, Schedule 8, Page 1 of 12 (17-492)

A. Please provide a description of Real Time Non Excessive Energy Amount charges and how they are determined.

B. Please explain why 100 percent of Real Time Non Excessive Energy Amount charges are assigned to Retail.

C. Please explain how the Real Time Non Excessive Energy Amount charges assigned to Retail are allocated to Minnesota Retail. Please provide any allocators used.

D. Please explain why the Real Time Non Excessive Energy Amount – System increased significantly from $546,921 in 16-523 to $2,357,643 in 17-492.

Response:

A. Real Time Non Excessive Energy credits and charges represent the difference between what was settled in the Day Ahead Market and what actually happened in the Real Time Market. These charges apply to generation resource. For example, a resource in the Day Ahead Market is paid an awarded volume of 500MW multiplied by a Day Ahead Locational Marginal Price of $30 for a total payment of $15,000. In the Real Time market the resource only produces 450MW. The resource must buy back 50MW at a Real Time Locational Marginal Price of $20 for a charge of $1000. The resources total energy settlement is $14,000 with a $1,000 charge settling in the Real Time Non Excessive Energy Amount.

B. Real Time Non Excessive Energy Amount charges are assigned to both Retail and Asset Based. The Asset Based allocation can be found in the MISO Day 2 schedule on the Real Time Asset Energy line.

C. Real Time Non Excessive Energy Amount charges are allocated to Minnesota Retail based on Minnesota's jurisdictional MWh as a percentage of the total retail system MWh.

See the table below for allocators used in calculating the amounts referenced in Part D.

	Jul-15	Jul-16
MWh		
(1) Total System MWh	3,901,567	4,017,719
Minnesota State MWh	2,920,992	3,013,278
Windsource MWh	12,549	12,892
(2) Net Minnesota State MWh	2,908,443	3,000,386
(2)/(1) MN MWh As % to Total Retail	74.546%	74.679%

D. The Real Time Non Excessive Energy Amount of $2,357,643 in Docket No. E999/AA-17-492 is a net value comprising approximately $200 million in gross sales and buybacks. The Real Time sale to buyback ratio increased slightly from this perspective. The increase could be attributed to a single unit that tripped offline on three different days in August 2016.

Preparer: Matt Schmidt / Allison Johnson
Title: Sr. Market Operation Financial Analyst / Principal Financial Consultant
Department: Market Operation Accounting / NSP Commercial Accounting
Telephone: 303-571-7519 / 303-571-6967
Date: September 24, 2018

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **12**
Topic: MISO Day 2 and ASM allocations
Reference(s): Attachment No. 9

Request:

(a) Has MP changed any of its allocations for MISO Day 2 and Ancillary Services Market (ASM)? If yes, please identify all changes in allocations and explain why the change is a better method of allocation.

RESPONSE:

Minnesota Power has not changed its allocation methods.

To be completed by responder

Response Date: September 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 9/13/2018
Type of Inquiry:	Financial	Response Due: 9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **13**
Topic: Asset Based Margins
Reference(s): MP's Rate Case GR-16-664

Request:

a) Please provide the actual costs and revenues and resulting actual asset based margin for 2017.

b) Please provide the asset based margin approved in MP's rate case E015/GR-16-664, including an appropriate reference to MP's rate case.

RESPONSE:

a) Please see TRADE SECRET "Table 1 – Asset-Based Wholesale Sales 2017 Actuals" below for actual costs, revenues and asset based margins for 2017.

b) The asset based margins approved in Minnesota Power's rate case E015/GR-16-664 were set at $35.8 million (Minnesota Jurisdictional) as stated in J. Pierce, Supplemental Direct Testimony and Schedules, page 10, line 3, and Supplemental Direct Schedule 5, page 17. This should be compared to the $34.3 million (Minnesota Jurisdictional) shown on Table 1 below.

To be completed by responder

Response Date: September 20, 2018
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: 218-723-7537

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by:	Nancy Campbell
Email Address(es):	nancy.campbell@state.mn.us
Phone Number(s):	651-539-1821

Table 1

Asset-Based Wholesale Sales 2017 Actuals									
	MWH	FUEL COST	MN JURISDICTION FUEL COST	SALES PRICE	MN JURISDICTION SALES PRICE	NET ENERGY MARGIN	MN JURISDICTION MARGIN	CAPACITY REVENUE	MN JURISDICTION CAPACITY REVENUE
MISO Market Sales	TRADE SECRET DATA EXCISED								
AEP									
Basin 100 MW									
Basin capacity sales									
NextEra									
MDU									
MISO Resource Adequacy									
unidentified capacity sale									
MISO Costs									
Total Wholesale Energy Sales	2,244,242	$ 51,514,973	$ 43,206,638	$ 79,367,618	$ 66,567,209	$ 27,852,646	$ 23,360,571	$ 13,375,272	$ 10,969,997
							Total Margin		$ 41,227,918
							MN Jurisdictional Margin		$ 34,330,568
MN Jurisdictional									
Energy	0.83872								
Demand	0.82017								

To be completed by responder

Response Date:	September 20, 2018
Response by:	Laurel Udenberg
Email Address:	ludenberg@mnpower.com
Phone Number:	218-723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **14**
Topic: MISO Day 2 and ASM net costs
Reference(s): Attachment No. 9

Request:

a) Footnote 1 states, "All Administrative Charges reflected in the Retail column are now in the base cost of fuel (not recovered in the FAC)." Please explain if the MISO administrative costs were included in base rates or base cost of fuel in MP's recent rate case E015/GR-16-664. Please include page references to MP's recent rate case to support your response.

b) Page 77 of 80 of Attachment 9 shows the July 2016 to June 2017 "Grand Total" of $44,597,707, does this amount reflect the total for both MISO Day 2 and ASM net costs? Please explain your response.

c) Page 77 of 80 of Attachment 9 shows the July 2016 to June 2017 "Subtotal" of $513,269, does this amount reflect the total ASM net costs? Please explain your response.

RESPONSE:

a) The wording on that footnote is incorrect and should read "All Administrative Charges reflected in the Retail Column are now in ***base rates.***" The footnote has been updated for future filings.

MISO administrative costs were included in the base energy rate as shown in the Company's recent rate case E015/GR-16-664, Compliance Schedule 16, page 19 of 46, line 10. Line 10 is

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To be completed by responder

Response Date: 9/24/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Purchase Power Energy (which includes MISO Admin costs) and is charged to customers as a "Base Energy Charge."

b) Yes- The $44,597,707 includes all MISO Day 2 and ASM Charges. Please refer to Table 1 Below for the breakdown of MISO Day 2 and ASM Charges for July 2016 – June 2017.

Table: 1

July 2016 - June 2017	
Energy Charges	$23,334,408.27
Enery Loss Charges	$12,767,723.51
Administration Charges	$1,712,119.23
Congestion, FTR, and ARR Charges	$4,498,323.96
RSG and Make Whole Charges	($70,739.25)
RNU and Misc. Charges	$1,842,602.06
ASM Charges	$513,269.39
Grand Total	**$44,597,707.17**

c) Yes- The $513,269.00 is the total ASM Charges from June 2017 – July 2018. The only ASM charges not included in the subtotal of $513,269 are Excessive and Non Excessive Energy charges which are included in the Energy section "subtotal" of $23,334,408.27 on Page 75 of attachment 9. Please refer to Table 2 and Table 3 Below for the breakdown of MISO Day 2 and ASM Charges and a list of MISO ASM Charge types from MISO.

To be completed by responder

Response Date: 9/24/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 2:

	ASM Charges
Jul-17	$14,985.19
Aug-17	$5,859.08
Sep-17	$28,348.99
Oct-17	$74,145.50
Nov-17	$47,092.65
Dec-17	$54,568.14
Jan-18	$45,346.34
Feb-18	$23,239.11
Mar-18	$55,502.36
Apr-18	$85,915.57
May-18	$76,845.73
Jun-18	$1,420.73
Total	$513,269.39

Table 3:

Ancillary Service Charge Types	
Day-Ahead Regulation Amount	DA_ASM_REG
Day-Ahead Spinning Reserve Amount	DA_ASM_SPIN
Day-Ahead Supplemental Reserve Amount	DA_ASM_SUPP
Real-Time Regulation Amount	RT_ASM_REG
Real-Time Spinning Reserve Amount	RT_ASM_SPIN
Real-Time Supplemental Reserve Amount	RT_ASM_SUPP
Regulation Cost Distribution Amount	RT_ASM_REG_DIST
Spinning Reserve Cost Distribution Amount	RT_ASM_SPIN_DIST
Supplemental Reserve Cost Distribution Amount	RT_ASM_SUPP_DIST
Real-Time Excessive Deficient Energy Deployment Charge Amount	RT_ASM_EXE_DFE_DE
Non-Excessive Energy Amount	RT_ASM_NXE
Excessive Energy Amount	RT_ASM_EXE
Net Regulation Adjustment Amount	RT_ASM_NRGA
Contingency Reserve Deployment Failure Charge Amount	RT_ASM_CRDFC

To be completed by responder

Response Date: 9/24/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-355-3678

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 9/13/2018
Type of Inquiry:	Financial	Response Due: 9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **15**
Topic: MISO Day 2 and ASM net costs
Reference(s): Attachment No. 9 for Docket Nos. AA-16-523 and AA-17-492

Request:

a) Please explain the main drivers that caused the Day 2 and ASM total net costs to increase from $30.219 million for (July 2015 to June 2016 on Attachment 9 page 78 of 81) to $44.597 million for (July 2016 to June 2017 on Attachment 9 page 77 of 80) .

b) Please explain the main drivers that caused the ASM total net costs to increase from $83,105 for (July 2015 to June 2016 on Attachment 9 page 78 of 81) to $513,269 for (July 2016 to June 2017 on Attachment 9 page 77 of 80).

RESPONSE:

a) Asset Energy increased roughly $10 million and Energy Losses increased roughly $3 million from July 2015 – June 2016 to July 2016 – June 2017. This makes up 93 percent of the total 14.3 million dollar increase. Most of the increase was in the Day Ahead which was caused by increased LMP prices. Day Ahead LMP's at MP.MP averaged $20.35 from July 2015 – June 2016 and escalated to $23.76 from July 2016 – June 2017.

b) Regulation Reserve Cost Distribution increased about $160,000, Spinning Reserve Cost Distribution increased about $187,000, and Supplemental Reserve Cost Distribution increased about $72,000 when comparing July 2015 – June 2016 to July 2016 – June 2017. The three Distribution Charges

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To be completed by responder

Response Date: 9/21/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-341-2163

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

that increased are MISO procurement costs that are distributed to Asset Owners based on their load.

To be completed by responder

Response Date: 9/21/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-341-2163

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 9/13/2018
Type of Inquiry:	Financial	Response Due: 9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **16**
Topic: ASM net costs
Reference(s): Attachment No. 9 for Docket Nos. AA-16-523 and AA-17-492

Request:

a) For ASM total costs, please explain the difference in the $513,269 for (July 2016 to June 2017 on Attachment 9 page 77 of 80) and the $512,428 as discussed in "ASM Charge Summary" section on Attachment 10, page 3 of 12.

RESPONSE:

The ASM costs as shown on Attachment 9 are based on when they were recorded in the Company's general ledger and allocated to the fuel clause adjustment. The ASM costs as shown on Attachment 10 are based on the operating day they pertain to. Attachment 10 numbers are updated through the most current settlement statements received prior to preparing the attachment for filing with the AAA.

To be completed by responder

Response Date: September 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 9/13/2018
Type of Inquiry:	Financial	Response Due: 9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **17**
Topic: MISO Day 2 and ASM charges
Reference(s): Attachment No. 9

Request:

a) Please provide the MISO bills including a summary sheet of the MISO bills that support the $6.232 million in MISO Day 2 and ASM net costs for April 2017 (Attachment 9, page 59 of 80).

b) Please support MP's cost allocation of $6,030,438 in costs and $391,092 in revenues (for a net costs of $5,639,346) assigned to FPE Retail out of the Grand Total of $6,231,856 for MISO Day 2 and ASM net costs in April 2017 (Attachment 9, page 59 of 80).

RESPONSE:

a) The MISO billing statements (weekly invoices) for the month of April, 2017 are reconciled to the monthly allocation tables in DOC IR 1.1 Attach. The reconciliation involves adding together the MISO invoice information and the current month accrual, subtracting the prior month accrual and adding any miscellaneous adjustments. The weekly invoices are included as attachments DOC IR 1.6 Attach to DOC IR 1.13 Attach.

b) MP's cost allocation of $6,030,438 in costs and $391,092 in revenues assigned to FPE Retail are supported by the data shown in DOC IR 1.2 Attach.

To be completed by responder

Response Date: 9/21/2018
Response by: Ryan LaCoursiere
Email Address: rlacoursiere@mnpower.com
Phone Number: 218-341-2163

	MINNESOTA POWER MISO MONTHLY ALLOCATION	Account Number	April 2017	Date Invoice Paid 4/25/2017	5/2/2017	5/9/2017	5/16/2017	5/23/2017	5/30/2017	Total	Difference	FPE Ret Mwh	FPE Ret Cost
	S7 Days			4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17					
	S14 Days				4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17				
	Day Ahead and Real Time Energy												
1a	Day Ahead Asset Energy	44700-0000 or 55500-0000 or 55500-0050	6,495,957.60	1,920,432.94	823,653.93	2,002,209.37	1,560,516.91	606,886.71	-	6,913,699.86	0.20		
5	Day Ahead Non-Asset Energy	55500-0027	(1,733,015.05)	(307,213.50)	(407,954.45)	(474,446.50)	(420,457.60)	(141,516.00)	-	(1,751,588.05)	(18,573.00)		
13a	Real Time Asset Energy	44700-0000 or 55500-0000 or 55500-0050	232,483.81	97,253.97	(58,936.47)	64,501.68	68,751.35	15,823.27	(4,785.30)	182,608.50	(14,918.24)		
	Excessive Energy Amount	55500-0066	42,546.49	8,046.16	15,234.74	10,706.57	5,816.11	3,437.60	-	43,241.18	694.69		
	Non-Excessive Energy Amount	55500-0069	(201,658.88)	(178,260.29)	(64,261.31)	9,490.06	79,284.78	(59,144.47)	-	(212,891.23)	(11,232.35)		
22	Real Time Non-Asset Energy	55500-0043	(117,860.10)	(65,373.27)	(39,178.69)	4,246.56	1,277.82	1,036.32	-	(97,991.26)	19,868.84		
	Subtotal		**4,718,453.87**									**693,797**	**4,635,383.49**
	Day Ahead and Real Time Energy Loss												
1c	Day Ahead Loss	44700-0000 or 55500-0000 or 55500-0050	614,453.72	-	-	-	-	-	-	-			407,174.55
3	Day Ahead Financial Bilateral Transaction Loss	55500-0022	337,992.64	87,735.02	84,908.47	83,130.71	78,167.64	10,946.30	-	344,888.14	6,895.50		224,291.92
13c	Real Time Loss	44700-0000 or 55500-0000 or 55500-0050	28,123.91	-	-	-	-	-	-	-			18,636.62
14	Real Time Distribution of Losses	55500-0041	(121,337.27)	(21,161.83)	(48,382.59)	(13,839.62)	(48,799.62)	(2,158.56)	77.18	(134,265.04)	(12,927.77)		-
16	Real Time Financial Bilateral Transaction Loss	55500-0038	-	-	-	-	-	-	-	-			-
	Subtotal		**859,233.00**									**693,797**	**650,103.09**
	Virtual Energy												
12	Day Ahead Virtual Energy	55500-0030	-	-	-	-	-	-	-	-	-		-
27	Real Time Virtual Energy	55500-0049	-	-	-	-	-	-	-	-	-		-
	Subtotal		**-**									**693,797**	**-**
	Schedule 16 & 17 1/												
4	Day Ahead Market Administration (Schedule 17)	55500-0020	122,735.66	27,741.26	32,625.48	30,150.01	30,179.33	6,828.52	-	127,524.60	4,788.94		81,447.38
19	Real Time Market Administration (Schedule 17)	55500-0036	9,748.40	2,249.28	2,421.81	2,156.23	3,193.36	592.76	0.95	10,614.39	865.99		6,469.04
29	Financial Transmission Rights Market Administration (Schedule 16)	55500-0031	4,105.30	960.48	960.48	960.48	960.48	266.88	-	4,108.80	3.50		2,724.28
	Subtotal		**136,589.36**									**693,797**	**90,640.70**

	MINNESOTA POWER / MISO MONTHLY ALLOCATION	Account Number	April 2017	Date Invoice Paid 4/25/2017	5/2/2017	5/9/2017	5/16/2017	5/23/2017	5/30/2017	Total	Difference	FPE Ret Mwh	FPE Ret Cost
	S7 Days			4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17					
	S14 Days				4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17				
	Congestion, FTRs & ARRs												
1b	Day Ahead Congestion	44700-0000 or 55500-0000 or 55500-0050	(196,711.26)	-	-	-	-	-	-	-			-
13b	Real Time Congestion	44700-0000 or 55500-0000 or 55500-0050	(92,917.46)	-	-	-	-	-	-	-			-
2	Day Ahead Financial Bilateral Transaction Congestion	55500-0021	157,488.28	47,578.48	75,363.46	27,158.66	38,495.06	7,858.10	-	196,453.76	38,965.48		104,509.22
15	Real Time Financial Bilateral Transaction Congestion	55500-0037	-	-	-	-	-	-	-	-	-		-
	Auction Revenue Rights Transaction Amount	55500-0058	(55,129.21)	(55,129.21)	-	-	-	-	-	(55,129.21)	-		-
	Financial Transmission Rights Annual Transaction Amount	55500-0059	146,543.25	146,543.25	-	-	-	-	-	146,543.25	-		97,246.10
	Auction Revenue Rights Infeasible Uplift Amount	55500-0060	13,702.75	13,705.93	-	-	-	-	-	13,705.93	3.18		9,093.14
	Auction Revenue Rights Stage 2 Distribution Amount	55500-0061	(55,277.60)	(56,392.68)	-	-	-	-	-	(56,392.68)	(1,115.08)		-
28	Financial Transmission Rights Hourly Allocation	55500-0032	(19,702.75)	(12,874.01)	(17,055.23)	(6,774.11)	(16,194.71)	(8,168.99)	-	(61,067.05)	(41,364.30)		-
30	Financial Transmission Rights Monthly Allocation	55500-0033	(5,189.74)	-	-	-	-	(13,302.63)	-	(13,302.63)	(8,112.89)		-
32	Financial Transmission Rights Yearly Allocation	55500-0035	-	-	-	-	-	-	-	-	-		-
	Financial Transmission Rights Full Funding Guarantee Amount	55500-0054	(3,109.71)	(1,036.04)	(4,017.33)	(2,125.78)	(3,089.96)	10,269.11	-	-	3,109.71		-
	FTR Guarantee Uplift Amount	55500-0055	3,109.71	1,036.04	4,017.33	2,125.78	3,089.96	(10,269.11)	-	-	(3,109.71)		2,063.60
	Financial Transmission Rights Monthly Transaction Amount	55500-0056	34,302.43	34,302.43	-	-	-	-	-	34,302.43	-		22,763.09
31	Financial Transmission Rights Transaction	55500-0034	-	-	-	-	-	-	-	-	-		-
	Subtotal		**(72,891.31)**									**693,797**	**235,675.16**
	RSG & Make Whole Payments												
10	Day Ahead Revenue Sufficiency Guarantee Distribution	55500-0028	35,909.40	9,660.17	8,100.82	5,812.32	4,161.36	1,389.61	(2.04)	29,122.24	(6,787.16)		23,829.48
11	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment	55500-0029	(94.42)	(5.24)	(38.85)	(18.52)	(44.20)	(45.26)	-	(152.07)	(57.65)		-
	Real Time Price Volatility Make Whole Payment	55500-0057	(5,026.58)	(980.98)	(971.87)	(1,758.47)	(1,783.28)	(613.63)	-	(6,108.23)	(1,081.65)		-
24	Real Time Revenue Sufficiency Guarantee First Pass Dist	55500-0046	81,515.22	16,277.94	11,790.07	24,161.28	24,332.63	7,484.91	140.72	84,187.55	2,672.33		54,093.50
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	55500-0047	-	-	-	-	-	-	-	-	-		-
	Subtotal		**112,303.62**									**693,797**	**77,922.98**
	RNU & Misc Charges												
20	Real Time Miscellaneous	55500-0042	183,008.84	-	-	-	-	-	-	-	(183,008.84) **		121,444.67
21	Real Time Net Inadvertent Distribution	55500-0044	18,899.89	11,366.43	2,086.90	15,101.07	(3,451.59)	1,079.28	117.69	26,299.78	7,399.89		12,541.97
23	Real Time Revenue Neutrality Uplift Amount	55500-0045	191,927.72	20,801.86	27,389.79	108,663.14	26,060.37	34,174.81	(84.63)	217,005.34	25,077.62		127,363.23
26	Real Time Uninstructed Deviation	55500-0048	-	-	-	-	-	-	-	-	-		-
27	Demand Response Allocation Uplift Amount	55500-0077	-	-	-	-	-	-	-	-	-		-
33	Day Ahead Ramp Capability Amount	55500-0079	(1,777.16)	(590.59)	(622.12)	(368.87)	(333.61)	(1,518.16)	-	(3,433.35)	(1,656.19)		-
34	Real Time Ramp Capability Amount	55500-0080	192.82	82.80	17.83	59.26	39.55	372.03	-	571.47	378.65		127.96
	Subtotal		**392,252.11**									**693,797**	**261,477.82**

#	MINNESOTA POWER / MISO MONTHLY ALLOCATION	Account Number	April 2017	Date Invoice Paid 4/25/2017	5/2/2017	5/9/2017	5/16/2017	5/23/2017	5/30/2017	Total	Difference	FPE Ret Mwh	Cost
	S7 Days			4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17					
	S14 Days				4/1/17 - 4/7/17	4/8/17 - 4/14/17	4/15/17 - 4/21/17	4/22/17 - 4/28/17	4/29/17 - 4/30/17				
	Grandfathered Charge Types												
6	Day Ahead Congestion Rebate on Carve-Out Grandfathered	55500-0023	-	-	-	-	-	-	-	-	-		
7	Day Ahead Losses Rebate on Carve-Out Grandfathered	55500-0024	-	-	-	-	-	-	-	-	-		
8	Day Ahead Congestion Rebate on Option B Grandfathered	55500-0025	-	-	-	-	-	-	-	-	-		
9	Day Ahead Losses Rebate on Option B Grandfathered	55500-0026	-	-	-	-	-	-	-	-	-		
17	Real Time Losses Rebate on Carve-Out Grandfathered	55500-0040	-	-	-	-	-	-	-	-	-		
18	Real Time Congestion Rebate on Carve-Out Grandfathered	55500-0039	-	-	-	-	-	-	-	-	-		
	Subtotal		-									693,797	-
	ASM Charge Types (12 Other)												
	Day Ahead Regulation Amount	55500-0062	(4,155.40)	(963.77)	(1,253.92)	(841.65)	(1,001.20)	(5,029.79)	-	(9,090.33)	(4,934.93)		-
	Day Ahead Spinning Reserve Amount	55500-0063	(28,978.25)	(5,629.90)	(10,681.36)	(5,153.16)	(6,397.15)	(6,205.86)	-	(34,067.43)	(5,089.18)		-
	Day Ahead Supplemental Reserve Amount	55500-0064	-	-	-	-	-	-	-	-	-		-
	Contingency Reserve Deployment Failure Charge Amount	55500-0065	-	-	-	-	-	-	-	-	-		-
	Net Regulation Adjustment Amount	55500-0068	(339.97)	(113.71)	(70.86)	(121.91)	29.41	5.43	-	(271.64)	68.33		-
	Real Time Regulation Amount	55500-0070	290.97	46.86	130.86	(617.78)	135.28	4,053.31	-	3,748.53	3,457.56		193.09
	Regulation Reserve Cost Distribution Amount	55500-0071	38,994.24	8,475.19	9,767.32	9,006.99	8,752.61	2,692.74	(9.28)	38,685.57	(308.67)		25,876.58
	Real-Time Excessive Deficient Deployment Charge Amount	55500-0067	4,438.09	920.83	1,182.35	1,278.93	1,313.83	367.19	0.01	5,063.14	625.05		2,945.12
	Real Time Spinning Reserve Amount	55500-0072	3,818.07	711.89	2,555.83	(98.49)	1,023.77	3,102.59	-	7,295.59	3,477.52		2,533.67
	Spinning Reserve Cost Distribution Amount	55500-0073	57,347.04	11,853.29	12,410.51	14,836.71	14,565.40	4,162.51	(15.88)	57,812.54	465.50		38,055.50
	Real Time Supplemental Reserve Amount	55500-0074	(12.37)	-	-	(9.97)	-	-	-	(9.97)	2.40		-
	Supplemental Reserve Cost Distribution Amount	55500-0075	14,513.15	2,819.07	4,697.02	3,096.72	2,396.63	410.68	(0.96)	13,419.16	(1,093.99)		9,630.93
	Subtotal		**85,915.57**									**693,797**	**79,234.88**
	Grand Total		**6,231,856.22**	**1,764,876.55**	**465,889.95**	**1,912,677.70**	**1,450,990.72**	**475,268.20**	**(4,561.54)**	**6,065,141.58**	**(196,550.72)**	**693,797**	**6,030,438.12**

** Most of the difference for the Real Time Miscellaneous Amount of ($183,008.84) is due to the following charge that occurred on 12/15/2016 (S105):

12/15/2016	Thursday	172629.20	Charge of $11,000,000 for payments to SPP and Joint Parties based on the adjusted Capacity Factor for Available System Capacity Usage from February 2016 to January 2017. Cost distribution based on Load Ratio Share for the period.

1/ All Administration Charges ref

2/ Accounts 55500-0051 through

3/ Accounts 55500-0076 are not r

NOTE:

DA and RT Asset Energy amounts h
Other Asset Backed Sales includes l
DA and RT Asset Energy and DA an

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MINNESOTA POWER

MISO MONTHLY ALLOCATION

	Account Number	April 2017	ail		FAC Resale				Subtotal FPE and FAC	MISO Non-Liquidation			
S7 Days													
S14 Days													
			Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Cost/(Revenue)	Mwh	Cost	Mwh	Revenue
Day Ahead and Real Time Energy													
Day Ahead Asset Energy	44700-0000 or 55500-0000 or 55500-0050	6,495,957.60							-				
Day Ahead Non-Asset Energy	55500-0027	(1,733,015.05)							-				
Real Time Asset Energy	44700-0000 or 55500-0000 or 55500-0050	232,483.81							-				
Excessive Energy Amount	55500-0066	42,546.49							-				
Non-Excessive Energy Amount	55500-0069	(201,658.88)							-				
Real Time Non-Asset Energy	55500-0043	(117,860.10)							-				
Subtotal		**4,718,453.87**			**129,331**	**882,930.19**			5,518,313.68	**25,912**			
Day Ahead and Real Time Energy Loss													
Day Ahead Loss	44700-0000 or 55500-0000 or 55500-0050	614,453.72		-		77,557.06		-	484,731.61		14,925.76		-
Day Ahead Financial Bilateral Transaction Loss	55500-0022	337,992.64		-		42,722.27		-	267,014.19		8,081.18		-
Real Time Loss	44700-0000 or 55500-0000 or 55500-0050	28,123.91		-		3,549.83		-	22,186.45		683.16		-
Real Time Distribution of Losses	55500-0041	(121,337.27)		(80,519.41)		-		(15,337.03)	(95,856.44)		-		(2,901.09)
Real Time Financial Bilateral Transaction Loss	55500-0038	-		-		-		-	-		-		-
Subtotal		**859,233.00**	**693,797**	**(80,519.41)**	**129,331**	**123,829.16**	**129,331**	**(15,337.03)**	**678,075.80**	**25,912**	**23,690.11**	**25,912**	**(2,901.09)**
Virtual Energy													
Day Ahead Virtual Energy	55500-0030	-		-		-		-	-				
Real Time Virtual Energy	55500-0049	-		-		-		-	-				
Subtotal		**-**	**693,797**	**-**	**129,331**	**-**	**129,331**	**-**	**-**	**25,912**	**-**	**25,912**	**-**
Schedule 16 & 17 1/													
Day Ahead Market Administration (Schedule 17)	55500-0020	122,735.66		-		15,513.79		-	96,961.17		2,934.53		-
Real Time Market Administration (Schedule 17)	55500-0036	9,748.40		-		1,232.20		-	7,701.24		233.08		-
Financial Transmission Rights Market Administration (Schedule 16)	55500-0031	4,105.30		-		518.91		-	3,243.19		98.16		-
Subtotal		**136,589.36**	**693,797**	**-**	**129,331**	**17,264.90**	**129,331**	**-**	**107,905.59**	**25,912**	**3,265.76**	**25,912**	**-**

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MINNESOTA POWER	Account												
MISO MONTHLY ALLOCATION	Number	April 2017	ail		FAC Resale				Subtotal FPE and FAC	MISO Non-Liquidation			
S7 Days													
S14 Days													
			Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Cost/(Revenue)	Mwh	Cost	Mwh	Revenue
Congestion, FTRs & ARRs													
Day Ahead Congestion	44700-0000 or 55500-0000 or 55500-0050	(196,711.26)		(130,352.89)		-		(24,829.12)	(155,182.02)		-		(4,778.34)
Real Time Congestion	44700-0000 or 55500-0000 or 55500-0050	(92,917.46)		(61,572.78)		-		(11,728.15)	(73,300.93)		-		(2,257.07)
Day Ahead Financial Bilateral Transaction Congestion	55500-0021	157,488.28		-		19,906.52		-	124,415.74		3,765.44		-
Real Time Financial Bilateral Transaction Congestion	55500-0037	-		-		-		-	-		-		-
Auction Revenue Rights Transaction Amount	55500-0058	(55,129.21)		(36,583.74)		-		(6,968.33)	(43,552.08)		-		(1,318.10)
Financial Transmission Rights Annual Transaction Amount	55500-0059	146,543.25		-		18,523.07		-	115,769.17		3,503.75		-
Auction Revenue Rights Infeasible Uplift Amount	55500-0060	13,702.75		-		1,732.03		-	10,825.17		327.62		-
Auction Revenue Rights Stage 2 Distribution Amount	55500-0061	(55,277.60)		(36,682.22)		-		(6,987.09)	(43,669.30)		-		(1,321.65)
Financial Transmission Rights Hourly Allocation	55500-0032	(19,702.75)		(13,074.74)		-		(2,490.43)	(15,565.17)		-		(471.08)
Financial Transmission Rights Monthly Allocation	55500-0033	(5,189.74)		(3,443.91)		-		(655.98)	(4,099.89)		-		(124.08)
Financial Transmission Rights Yearly Allocation	55500-0035	-		-		-		-	-		-		-
Financial Transmission Rights Full Funding Guarantee Amount	55500-0054	(3,109.71)		(2,063.60)		-		(393.07)	(2,456.67)		-		(74.35)
FTR Guarantee Uplift Amount	55500-0055	3,109.71		-		393.07		-	2,456.67		74.35		-
Financial Transmission Rights Monthly Transaction Amount	55500-0056	34,302.43		-		4,335.83		-	27,098.92		820.15		-
Financial Transmission Rights Transaction	55500-0034	-		-		-		-	-		-		-
Subtotal		**(72,891.31)**	**693,797**	**(283,773.89)**	**129,331**	**44,890.51**	**129,331**	**(54,052.17)**	**(57,260.39)**	**25,912**	**8,491.32**	**25,912**	**(10,344.67)**
RSG & Make Whole Payments													
Day Ahead Revenue Sufficiency Guarantee Distribution	55500-0028	35,909.40		-		4,538.95		-	28,368.43		858.57		-
Day Ahead Revenue Sufficiency Guarantee Make Whole Payment	55500-0029	(94.42)		(62.66)		-		(11.93)	(74.59)		-		(2.26)
Real Time Price Volatility Make Whole Payment	55500-0057	(5,026.58)		(3,335.64)		-		(635.36)	(3,971.00)		-		(120.18)
Real Time Revenue Sufficiency Guarantee First Pass Dist	55500-0046	81,515.22		-		10,303.52		-	64,397.02		1,948.98		-
Real Time Revenue Sufficiency Guarantee Make Whole Payment	55500-0047	-		-		-		-	-		-		-
Subtotal		**112,303.62**	**693,797**	**(3,398.30)**	**129,331**	**14,842.47**	**129,331**	**(647.29)**	**88,719.86**	**25,912**	**2,807.55**	**25,912**	**(122.44)**
RNU & Misc Charges													
Real Time Miscellaneous	55500-0042	183,008.84		-		23,132.32		-	144,576.98		4,375.62		-
Real Time Net Inadvertent Distribution	55500-0044	18,899.89		-		2,388.95		-	14,930.91		451.88		-
Real Time Revenue Neutrality Uplift Amount	55500-0045	191,927.72		-		24,259.66		-	151,622.90		4,588.87		-
Real Time Uninstructed Deviation	55500-0048	-		-		-		-	-		-		-
Demand Response Allocation Uplift Amount	55500-0077	-		-		-		-	-		-		-
Day Ahead Ramp Capability Amount	55500-0079	(1,777.16)		(1,179.32)		-		(224.63)	(1,403.96)		-		(42.49)
Real Time Ramp Capability Amount	55500-0080	192.82		-		24.37		-	152.33		4.61		-
Subtotal		**392,252.11**	**693,797**	**(1,179.32)**	**129,331**	**49,805.30**	**129,331**	**(224.63)**	**309,879.17**	**25,912**	**9,420.98**	**25,912**	**(42.49)**

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MINNESOTA POWER MISO MONTHLY ALLOCATION	Account Number	April 2017	ail		FAC Resale				Subtotal FPE and FAC	MISO Non-Liquidation			
S7 Days S14 Days			Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Cost/(Revenue)	Mwh	Cost	Mwh	Revenue
Grandfathered Charge Types													
Day Ahead Congestion Rebate on Carve-Out Grandfathered	55500-0023	-							-				
Day Ahead Losses Rebate on Carve-Out Grandfathered	55500-0024	-							-				
Day Ahead Congestion Rebate on Option B Grandfathered	55500-0025	-							-				
Day Ahead Losses Rebate on Option B Grandfathered	55500-0026	-							-				
Real Time Losses Rebate on Carve-Out Grandfathered	55500-0040	-							-				
Real Time Congestion Rebate on Carve-Out Grandfathered	55500-0039	-							-				
Subtotal		**-**	**693,797**	**-**	**129,331**	**-**	**129,331**	**-**	**-**	**25,912**	**-**	**25,912**	**-**
ASM Charge Types (12 Other)													
Day Ahead Regulation Amount	55500-0062	(4,155.40)		(2,757.52)		-		(525.24)	(3,282.77)		-		(99.35)
Day Ahead Spinning Reserve Amount	55500-0063	(28,978.25)		(19,229.97)		-		(3,662.85)	(22,892.82)		-		(692.85)
Day Ahead Supplemental Reserve Amount	55500-0064	-		-		-		-	-		-		-
Contingency Reserve Deployment Failure Charge Amount	55500-0065	-		-		-		-	-		-		-
Net Regulation Adjustment Amount	55500-0068	(339.97)		(225.60)		-		(42.97)	(268.58)		-		(8.13)
Real Time Regulation Amount	55500-0070	290.97		-		36.78		-	229.87		6.96		-
Regulation Reserve Cost Distribution Amount	55500-0071	38,994.24		-		4,928.87		-	30,805.45		932.33		-
Real-Time Excessive Deficient Deployment Charge Amount	55500-0067	4,438.09		-		560.97		-	3,506.09		106.11		-
Real Time Spinning Reserve Amount	55500-0072	3,818.07		-		482.60		-	3,016.28		91.29		-
Spinning Reserve Cost Distribution Amount	55500-0073	57,347.04		-		7,248.67		-	45,304.16		1,371.13		-
Real Time Supplemental Reserve Amount	55500-0074	(12.37)		(8.21)		-		(1.56)	(9.77)		-		(0.30)
Supplemental Reserve Cost Distribution Amount	55500-0075	14,513.15		-		1,834.46		-	11,465.39		347.00		-
Subtotal		**85,915.57**	**693,797**	**(22,221.30)**	**129,331**	**15,092.36**	**129,331**	**(4,232.63)**	**67,873.30**	**25,912**	**2,854.81**	**25,912**	**(800.63)**
Grand Total		**6,231,856.22**	**693,797**	**(391,092.23)**	**129,331**	**1,148,654.88**	**129,331**	**(74,493.76)**	**6,713,507.02**	**25,912**	**50,530.52**	**25,912**	**(14,211.32)**

lected in the Retail column are now in the base cost of fuel (not recovered in the FPE)

55500-0053 are not recovered through the FPE

ecovered through FPE for Resource Adequacy since it relates to capacity

ave been reduced by the generation to load LMP differences (RE) which are then shown in the Day Ahead L
liquidation sales which are not assessed MISO charges as all margins from liquidation sales are allocated to
d RT Non-Asset Energy is not allocated to MISO Non-Liquidation, MISO Liquidation, Others-Liquidation, Oth

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MINNESOTA POWER MISO MONTHLY ALLOCATION	Account Number	April 2017	MISO - Liquidation				Others - Liquidation				Others - Non-Liquidation				Contract Sales			
S7 Days S14 Days			Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue
Day Ahead and Real Time Energy																		
Day Ahead Asset Energy	44700-0000 or 55500-0000 or 55500-0050	6,495,957.60																
Day Ahead Non-Asset Energy	55500-0027	(1,733,015.05)																
Real Time Asset Energy	44700-0000 or 55500-0000 or 55500-0050	232,483.81																
Excessive Energy Amount	55500-0066	42,546.49																
Non-Excessive Energy Amount	55500-0069	(201,658.88)																
Real Time Non-Asset Energy	55500-0043	(117,860.10)																
Subtotal		**4,718,453.87**	**35,792**				**36,000**				**49,955**				**218,103**			
Day Ahead and Real Time Energy Loss																		
Day Ahead Loss	44700-0000 or 55500-0000 or 55500-0050	614,453.72										28,775.37		-		86,020.98		-
Day Ahead Financial Bilateral Transaction Loss	55500-0022	337,992.64										15,579.70		-		47,317.57		-
Real Time Loss	44700-0000 or 55500-0000 or 55500-0050	28,123.91										1,317.07		-		3,937.23		-
Real Time Distribution of Losses	55500-0041	(121,337.27)										-		(5,593.02)		-		(16,986.72)
Real Time Financial Bilateral Transaction Loss	55500-0038	-										-		-		-		-
Subtotal		**859,233.00**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**45,672.14**	**49,955**	**(5,593.02)**	**218,103**	**137,275.78**	**218,103**	**(16,986.72)**
Virtual Energy																		
Day Ahead Virtual Energy	55500-0030	-																
Real Time Virtual Energy	55500-0049	-																
Subtotal		**-**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**-**	**49,955**	**-**	**218,103**	**-**	**218,103**	**-**
Schedule 16 & 17 1/																		
Day Ahead Market Administration (Schedule 17)	55500-0020	122,735.66										5,657.48		-		17,182.48		-
Real Time Market Administration (Schedule 17)	55500-0036	9,748.40										449.35		-		1,364.74		-
Financial Transmission Rights Market Administration (Schedule 16)	55500-0031	4,105.30										189.23		-		574.73		-
Subtotal		**136,589.36**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**6,296.06**	**49,955**	**-**	**218,103**	**19,121.95**	**218,103**	**-**

MINNESOTA POWER	Account																	
MISO MONTHLY ALLOCATION	Number	April 2017	MISO - Liquidation				Others - Liquidation				Others - Non-Liquidation				Contract Sales			
S7 Days																		
S14 Days																		
			Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue
Congestion, FTRs & ARRs																		
Day Ahead Congestion	44700-0000 or 55500-0000 or 55500-0050	(196,711.26)										-		(9,212.15)		-		(27,538.76)
Real Time Congestion	44700-0000 or 55500-0000 or 55500-0050	(92,917.46)										-		(4,351.40)		-		(13,008.06)
Day Ahead Financial Bilateral Transaction Congestion	55500-0021	157,488.28										7,259.39		-		22,047.71		-
Real Time Financial Bilateral Transaction Congestion	55500-0037	-										-		-		-		-
Auction Revenue Rights Transaction Amount	55500-0058	(55,129.21)										-		(2,541.17)		-		(7,717.86)
Financial Transmission Rights Annual Transaction Amount	55500-0059	146,543.25										6,754.88		-		20,515.45		-
Auction Revenue Rights Infeasible Uplift Amount	55500-0060	13,702.75										631.63		-		1,918.33		-
Auction Revenue Rights Stage 2 Distribution Amount	55500-0061	(55,277.60)										-		(2,548.01)		-		(7,738.64)
Financial Transmission Rights Hourly Allocation	55500-0032	(19,702.75)										-		(908.19)		-		(2,758.30)
Financial Transmission Rights Monthly Allocation	55500-0033	(5,189.74)										-		(239.22)		-		(726.54)
Financial Transmission Rights Yearly Allocation	55500-0035	-										-		-		-		-
Financial Transmission Rights Full Funding Guarantee Amount	55500-0054	(3,109.71)										-		(143.34)		-		(435.35)
FTR Guarantee Uplift Amount	55500-0055	3,109.71										143.34		-		435.35		-
Financial Transmission Rights Monthly Transaction Amount	55500-0056	34,302.43										1,581.16		-		4,802.20		-
Financial Transmission Rights Transaction	55500-0034	-										-		-		-		-
Subtotal		**(72,891.31)**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**16,370.40**	**49,955**	**(19,943.49)**	**218,103**	**49,719.03**	**218,103**	**(59,923.51)**
RSG & Make Whole Payments																		
Day Ahead Revenue Sufficiency Guarantee Distribution	55500-0028	35,909.40										1,655.24		-		5,027.17		-
Day Ahead Revenue Sufficiency Guarantee Make Whole Payment	55500-0029	(94.42)										-		(4.35)		-		(13.22)
Real Time Price Volatility Make Whole Payment	55500-0057	(5,026.58)										-		(231.70)		-		(703.70)
Real Time Revenue Sufficiency Guarantee First Pass Dist	55500-0046	81,515.22										3,757.43		-		11,411.79		-
Real Time Revenue Sufficiency Guarantee Make Whole Payment	55500-0047	-										-		-		-		-
Subtotal		**112,303.62**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**5,412.66**	**49,955**	**(236.05)**	**218,103**	**16,438.96**	**218,103**	**(716.92)**
RNU & Misc Charges																		
Real Time Miscellaneous	55500-0042	183,008.84										8,435.76		-		25,620.48		-
Real Time Net Inadvertent Distribution	55500-0044	18,899.89										871.19		-		2,645.91		-
Real Time Revenue Neutrality Uplift Amount	55500-0045	191,927.72										8,846.87		-		26,869.09		-
Real Time Uninstructed Deviation	55500-0048	-										-		-		-		-
Demand Response Allocation Uplift Amount	55500-0077	-										-		-		-		-
Day Ahead Ramp Capability Amount	55500-0079	(1,777.16)										-		(81.92)		-		(248.80)
Real Time Ramp Capability Amount	55500-0080	192.82										8.89		-		26.99		-
Subtotal		**392,252.11**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**18,162.70**	**49,955**	**(81.92)**	**218,103**	**55,162.47**	**218,103**	**(248.80)**

Apr17

MINNESOTA POWER MISO MONTHLY ALLOCATION	Account Number	April 2017	MISO - Liquidation				Others - Liquidation				Others - Non-Liquidation				Contract Sales			
S7 Days S14 Days			Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue	Mwh	Cost	Mwh	Revenue
Grandfathered Charge Types																		
Day Ahead Congestion Rebate on Carve-Out Grandfathered	55500-0023	-														-		-
Day Ahead Losses Rebate on Carve-Out Grandfathered	55500-0024	-														-		-
Day Ahead Congestion Rebate on Option B Grandfathered	55500-0025	-														-		-
Day Ahead Losses Rebate on Option B Grandfathered	55500-0026	-														-		-
Real Time Losses Rebate on Carve-Out Grandfathered	55500-0040	-														-		-
Real Time Congestion Rebate on Carve-Out Grandfathered	55500-0039	-														-		-
Subtotal		**-**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**-**	**49,955**	**-**	**218,103**	**-**	**218,103**	**-**
ASM Charge Types (12 Other)																		
Day Ahead Regulation Amount	55500-0062	(4,155.40)										-		(191.54)		-		(581.74)
Day Ahead Spinning Reserve Amount	55500-0063	(28,978.25)										-		(1,335.75)		-		(4,056.84)
Day Ahead Supplemental Reserve Amount	55500-0064	-										-		-		-		-
Contingency Reserve Deployment Failure Charge Amount	55500-0065	-										-		-		-		-
Net Regulation Adjustment Amount	55500-0068	(339.97)										-		(15.67)		-		(47.59)
Real Time Regulation Amount	55500-0070	290.97										13.41		-		40.73		-
Regulation Reserve Cost Distribution Amount	55500-0071	38,994.24										1,797.43		-		5,459.03		-
Real-Time Excessive Deficient Deployment Charge Amount	55500-0067	4,438.09										204.57		-		621.31		-
Real Time Spinning Reserve Amount	55500-0072	3,818.07										175.99		-		534.51		-
Spinning Reserve Cost Distribution Amount	55500-0073	57,347.04										2,643.40		-		8,028.35		-
Real Time Supplemental Reserve Amount	55500-0074	(12.37)										-		(0.57)		-		(1.73)
Supplemental Reserve Cost Distribution Amount	55500-0075	14,513.15										668.98		-		2,031.78		-
Subtotal		**85,915.57**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**5,503.79**	**49,955**	**(1,543.53)**	**218,103**	**16,715.72**	**218,103**	**(4,687.90)**
Grand Total		**6,231,856.22**	**35,792**	**-**	**35,792**	**-**	**36,000**	**-**	**36,000**	**-**	**49,955**	**97,417.76**	**49,955**	**(27,398.00)**	**218,103**	**294,433.90**	**218,103**	**(82,563.84)**

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **18**
Topic: FTRs & ARRs
Reference(s): Attachment No. 11

Request:

a) Please explain why MP has transactions that sink (see lines 1, 9-12 and 14-15 for example) on Attachment 11 page 3 of 5.

b) Please provide the related revenues to the two sink transactions noted in part (a) and explain why the costs and revenues or net amount benefits ratepayers.

<u>RESPONSE</u>:

a) From time to time, Minnesota Power may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. Minnesota Power actively sells any excess energy to the wholesale market to optimize the value of its generating facilities. Minnesota Power has bilateral transactions with sink locations as noted on Attachment 11 page 3 of 5 and cited in (a) due to its power market activities.

b) Please see TRADE SECRET "Table 1 - Monthly FTR Purchase" below, which illustrates the FTR Costs/Benefits associated with the two sink transactions that align with the bilateral transactions as referenced on Attachment 11 page 3 of 5. Minnesota Power utilizes FTRs to minimize MISO costs incurred by its customers.

To be completed by responder

Response Date: September 20, 2018
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: 201-723-7537

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Table 1

Monthly FTR Purchase

Source	Sink	Class Period	Month	Awarded FTRs	Clearing $/MW Month	Total Monthly Cost	FTR Value $/MW Month	FTR Revenue	FTR Cost/Benefit
TRADE SECRET DATA EXCISED									

To be completed by responder

Response Date: September 20, 2018
Response by: Laurel Udenberg
Email Address: ludenberg@mnpower.com
Phone Number: 201-723-7537

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: 19
Topic: Generation Maintenance Expenses
Reference(s): Attachment No. 12

Request:

a) Please provide the 2017 actuals and 2017 test year amounts approved in GR-16-664 for generation maintenance expense, in the same format as Attachment No. 12. Please explain any significant differences.

RESPONSE:

Refer to DOC IR 19 Attach for the requested 2017 actual and approved test year generation maintenance expense information.

Explanations for significant differences are provided below:

Steam Power Generation Maintenance:
FERC account 510 Maintenance Supervision and Engineering: 2017 actual expense is lower than the 2017 approved test year expense due to the upcoming planned retirement of Boswell Units 1&2 and the resulting staffing reductions. In Docket 16-664 MP did reduce MN Jurisdictional $3 million for an estimated average of 42 unfilled positions (Johnson Rebuttal Schedule 1). MP adjusted the 2017 test year for $3 million using FERC account #920 A&G Salaries. Johnson Rebuttal testimony page 3 states that "One of the main reasons that Minnesota Power has not reached its budgeted headcount is due to the closure of Boswell Energy Center ("BEC") Units 1 & 2 at the end of 2018".

To be completed by responder

Response Date: 9/24/2018
Response by: Rhonda Munger, Senior Budget Analyst/Sara Carlson, Cost & Pricing Analyst Senior
Email Address: rmunger@mnpower.com; scarlson@mnpower.com
Phone Number: 218-313-4496; 218-355-3019

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

FERC account 511 Maintenance of Structures: Actual 2017 expenses included items that were that were not originally budgeted. Examples of expenses incurred include filter replacement, preventive maintenance expenses, HVAC systems and safety equipment eye wash stations. These items accounted for $479,000 of the total variance and were identified as necessary for providing utility service during the course of routine 2017 maintenance work.

FERC account 512 Maintenance of Boiler Plant: Actual 2017 expenses were under by $4.3 million compared to the 2017 test year.

Timing related to the Boswell Unit 4 fall 2017 scheduled maintenance outage attributed $1.64 million of this variance. The fall scheduled maintenance outage scope and length changed from 3 weeks to 2 weeks. The 1 week portion of work was rescheduled to 2018 for a thorough inspection of the Unit 4 boiler prior to the extensive planned outage in 2020.

Boswell Unit 3 Main boiler feed pump repair budgeted in 2017 was so extensive it had to be overhauled extending the life of the equipment it qualified as a capitalized investment to the unit.

Hibbard Renewable Energy Center boiler maintenance expenses were included in the 2017 test year however the actual costs were captured primarily in FERC 502 Steam Expenses. This accounted for $1,600,000 of the variance.

FERC account 513 Maintenance of Electrical Plant and 514 Misc. Steam Plant: The variance of $1 million 2017 actuals in 513 being higher compared to the 2017 test year is due to some higher maintenance expenses and partially offset account #514 lower than budget by $383,838. These two maintenance accounts are strongly correlated. The 2017 test year budget amounts were developed in the summer 2016 so variances between actuals and budget occur between these two accounts because the maintenance work anticipated may change slightly based on the actual needs, priorities and performance at the generation units.

Hydro Power Generation

FERC account 543 Maintenance of Reservoirs, Dams and Waterways and 544 Maintenance of Electrical Plant: The variances off set each other as the actual work more accurately was classified to FERC account 543 versus

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To be completed by responder

Response Date: 9/24/2018
Response by: Rhonda Munger, Senior Budget Analyst/Sara Carlson, Cost & Pricing Analyst Senior
Email Address: rmunger@mnpower.com; scarlson@mnpower.com
Phone Number: 218-313-4496; 218-355-3019

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

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544. Continued maintenance at the St. Louis River dams following the 2012 flooding drove the work scope that had not been completed in the prior years.

Other Wind Power Generation

FERC Account 553 Maintenance of Generating and Electrical Plant and FERC Account 554 Maintenance of Misc. Other Pwr Generation Plt.: The variances off set each other as the actual 2017 work was more accurately classified to FERC account 554 versus 553.

To be completed by responder

Response Date: 9/24/2018
Response by: Rhonda Munger, Senior Budget Analyst/Sara Carlson, Cost & Pricing Analyst Senior
Email Address: rmunger@mnpower.com; scarlson@mnpower.com
Phone Number: 218-313-4496; 218-355-3019

DOC IR 19 Attach.xls

Steam Power Generation Maintenance	FERC Acct	2017 Actual Expenses [1]	Final Rates Test Year 2017 [2] E015/GR-16-664	2017 Actual vs. Test Year Variance
Maintenance Supervision and Engineering	510	4,074,056	5,403,455	-1,329,399
Maintenance of Structures	511	1,163,815	582,993	580,822
Maintenance of Boiler Plant	512	11,731,724	16,051,910	-4,320,186
Maintenance of Electric Plant	513	3,226,061	2,143,926	1,082,135
Maintenance of Misc. Steam Plant	514	4,725,423	5,109,261	-383,838
		24,921,079	29,291,545	-4,370,466
Hydraulic Power Generation Maintenance				
Maintenance Supervision and Engineering	541	474,160	514,969	-40,809
Maintenance of Structures	542	45,560	73,962	-28,402
Maintenance of Reservoirs, Dams and Waterways	543	1,152,771	604,374	548,397
Maintenance of Electric Plant	544	1,016,865	1,581,601	-564,736
Maintenance of Misc. Hydraulic Plant	545	1,306,137	1,058,911	247,226
		3,995,493	3,833,817	161,676
Other Power Generation - Wind Maintenance				
Maintenance Supervision and Engineering	551	25,426	0	25,426
Maintenance of Structures	552	32,835	15,000	17,835
Maintenance of Generating and Electric Plant	553	8,000,197	9,116,984	-1,116,787
Maintenance of Misc. Other Pwr Generation Plt.	554	1,580,917	211,331	1,369,586
		9,639,375	9,343,315	296,060
Total Generation Maintenance		38,555,947	42,468,677	-3,912,730

[1] 2017 FERC Form 1, pages 320 and 321, column (b), Amount for the Current Year.
[2] Attachment 12, O&M Schedule page 3, column Total Company Compliance 2017 Cost of Service Model or Docket E015/GR-16-664 Compliance Filing dated 6-28-18, Section VIII, CCOSS, column Total Company.

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Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 9/13/2018
Type of Inquiry:	Financial	Response Due: 9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: **20**
Topic: Offsetting Revenues
Reference(s): Attachment No. 15

Request:

a) On page 2 of 2 of Attachment 15, MP shows Offsetting Revenues for the June 1, 2016 to June 30, 2017 period that are passed back to ratepayers in the fuel clause via Intersystem Sales. Please show that the amount of Offsetting Revenues on page 2 of 2 of Attachment 15 ties to the monthly FCA Intersystem Sales for this AAA period. Please explain any differences.

RESPONSE:

The amount shown on Attachment 3 to the 2016-2017 AAA filing on page 2 of 5 for the line entitled "Less: Fuel Costs Recovered Through Inter-System Sales" includes more than just the amount of the off -setting revenues shown in Attachment 15 on page 2 of 2. Fuel costs recovered through inter-system sales includes all the costs allocated to MP's inter-system sales including but not limited to: company owned generation costs used to make asset based sales, costs of purchases sold to the market that were no longer needed to cover load, margins (gain or loss) from sales of purchases no longer needed to cover load and MISO costs allocated to asset based sales.

The portion of fuel costs recovered through inter- system sales that relates to generation or purchased power costs is calculated on an hourly basis through MP's energy pricing program. In any hour, costs from company generation or one or more purchase could be allocated to a particular inter-system sale depending on the volume of the sale and how many purchase MWh are not needed for load and can be allocated to that sale.

To be completed by responder

Response Date: September 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/AA-17-492	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	9/13/2018
Type of Inquiry:	Financial	Response Due:	9/24/2018

Requested by: Nancy Campbell
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

The current reports from MP's energy pricing program identify how many MWh from each purchase are used to cover load, but do not currently show which particular inter-system sale they allocated to. If a purchase is not used to cover load, then it was "liquidated" or sold to the market. That sale could be to a counterparty or more often than not, it is sold to the MISO market, along with other purchases, not needed to cover load in that particular hour.

Since MP's current reports do not provide a breakdown of which purchases were used to serve each particular sale, MP is unable to show how Attachment 15 "ties to the month FCA Intersystem Sales for the AAA period".

The total for "Fuel Costs Recovered Through Inter-System Sales" for the reporting period were $109,150,549 while the offsetting revenues related to MP's purchase power contracts was only $28,926,210, illustrating that there is more than just purchase power costs and margins included in that number as noted above.

To be completed by responder

Response Date: September 20, 2018
Response by: Leann Oehlerking-Boes
Email Address: lboes@mnpower.com
Phone Number: 218-355-3832

Public
Response to Information Request MN-DOC-30

OTTER TAIL POWER COMPANY
Docket No: E999/AA-17-492

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson, Nancy Campbell and Stephen Collins
Date Received: 09/19/2018
Date Due: 10/01/2018
Date of Response: 10/01/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Has OTP changed any of its allocations for MISO Day 2 and Ancillary Services Market (ASM)? If yes, please identify all changes in allocations and explain why the change is a better method of allocation.

Attachments: 0

Response:

There have been no changes to the allocations of MISO Day 2 and Ancillary Services Market charge types.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-17-492

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson, Nancy Campbell and Stephen Collins
Date Received: 09/19/2018
Date Due: 10/01/2018
Date of Response: 10/01/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Please provide the actual costs and revenues and resulting actual asset based margin for 2017.

Attachments: 1

Attachment 1 to IR MN-DOC-31.pdf

Response:

Attachment 1 to IR MN-DOC-31 contains the Asset Based margin costs and revenues for the time period of July 2016 through June 2017. This information is also found in the initial filing Part H Section 3 Attachment K, Columns F through I.

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2016 - June 2017 Includes Any Adjustments

		(A)	(B)		(C)	(D)		(E)
			ASSET BASED WHOLESALE					
	Charge Type Description	**Acct**	**MWh**		**Cost**	**MWh**		**Revenue**
1	DA Mkt Admin Amount	555.01	0	$	(3,809.05)	0	$	-
2	DA Asset Energy Amount	555.02	0	$	-	52,335	$	1,406,875.97
3	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$	(5,391.61)	0	$	171.17
4	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$	-	0	$	3,378.63
5	DA Schedule 24 Allocation Amount	555.33	0	$	(666.19)	0	$	-
6	RT Mkt Admin Amount	555.18	0	$	(13,841.09)	0	$	937.81
7	RT Misc Amount	555.25	0	$	(9.60)	0	$	-
8	RT Revenue Neutrality Uplift Amount	555.28	0	$	(42,232.04)	0	$	15,617.21
9	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$	(12,316.25)	0	$	929.04
10	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$	(613.99)	0	$	158,730.88
11	RT Schedule 23 Allocation Amount	555.34	0	$	(2,353.61)	0	$	168.75
12	RT Price Volatility Make Whole Payment	555.42	0	$	(62.69)	0	$	11,838.74
13	RT ASM Non-Excessive Energy Amount	555.55	(24,030)	$	(477,488.09)	161,991	$	3,557,670.37
14	RT ASM Excessive Energy Amount	555.56	(19)	$	(240.59)	243	$	4,403.43
15	NET MISO (Rev-Cost and MWh)		(24,049)	$	(559,024.80)	214,569	$	5,160,722.00
16	Fuel Cost					(190,520)	$	(3,775,601.35)
17	**TOTAL ASSET BASED WHOLESALE**					**0**	**$**	**826,095.85**

Public
Response to Information Request MN-DOC-32

OTTER TAIL POWER COMPANY
Docket No: E999/AA-17-492

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson, Nancy Campbell and Stephen Collins
Date Received: 09/19/2018
Date Due: 10/01/2018
Date of Response: 10/01/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Please explain what caused the changes in the following Schedule 10, Attachment I-1, pages 25-26 year-to-date costs from the 16-625 report to the 17-492 report:

- Line 3, DA Non-asset Energy Amount, from 67,244.09 to -1,381,140.51
- Line 22, RT congestion, from -124,207.15 to 156,747.00
- Line 50, RT ASM Non-Excessive Energy Amount, from 3,205,716.51 to 3,879,202.88

Attachments: 0

Response:

The DA non-asset energy charge type includes charges and credits related to all day-ahead interchange schedules and day-ahead financial schedules settled at commercial pricing nodes where an asset owner does not own an asset. Prior to November of 2015, the Otter Tail DA non-asset energy charge was primarily driven by two factors. The first being a credit received from MISO for energy injected by Western Area Power Administration to serve agency and municipal loads within the Otter Tail footprint. The second being a charge for exports of Otter Tail energy, leaving the MISO footprint, to serve Otter Tail load within the Western Area Power Administration footprint. Starting in November of 2015, as a result of Western Area Power Administration joining the Southwest Power Pool, Otter Tail began pseudo tying our load in the Western footprint back into the MISO footprint. Pseudo tying a load utilizes meter measurements and mathematical calculations to allow a balancing area (in this case MISO) to serve a load located geographically outside of its footprint. When the pseudo tie was initiated in November of 2015, load that had previously been viewed as an export to the Western footprint was now viewed as part of Otter Tail's MISO load. The export charge associated with the DA non-asset energy charge type was eliminated, leaving only the credit associated with Western's injection of energy into MISO to serve municipal and agency loads. The charge associated with serving the Otter Tail load geographically located in the Western footprint was shifted from the DA non-asset energy charge to the DA asset energy charge. Due to the magnitude difference between the DA non-asset energy charge and the DA asset energy charge it is difficult notice this change within the DA asset energy charge type.

The RT ASM non-excessive energy charge type is for credits and charges associated with generation imbalance between day-ahead and real-time schedules. The charge or credit is determined by subtracting the day ahead schedule (MWs) from the real time schedule (MWs) and multiplying that MW delta by the real-time LMP. Changing schedules and increased volatility in real-time pricing can result in substantial variability in the RT ASM non-excessive energy charge. The primary reason driving charges and credits in the RT ASM non-excessive energy charge type are due to changing market conditions. As market conditions change, MISO calls for updated dispatch instructions, resulting in changes between the DA and RT generation schedules, which in turn drive the charges and credits associated with the RT ASM non-excessive energy charge type. There are occasions where Otter Tail requires a change in the DA schedule relative to the RT schedule, including generator forced outage, testing, de-rates, etc.

Similarly, the RT congestion charge/credit can vary considerably due to deltas between the DA and RT market. This is evident in reviewing the monthly swings associated with this charge/credit. The specific reasons for changes are difficult to pinpoint as they include many different variables, including changing DA to RT load schedules, DA to RT generation schedules, changing transmission constraints, and numerous other market factors.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-17-492

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson, Nancy Campbell and Stephen Collins
Date Received: 09/19/2018
Date Due: 10/01/2018
Date of Response: 10/01/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Please explain all procedures used to allocate costs to the Minnesota jurisdiction. If already explained in the report, please cite the corresponding pages.

Attachments: 0

Response:

Otter Tail understands this question to refer to fuel and purchased power costs and how they are allocated to the Minnesota jurisdiction. As reflected in the monthly energy adjustment rider rate calculations, the monthly fuel clause rates are computed on a system basis, and then subsequently applied to Minnesota kWhs subject to the Fuel Clause Adjustment. The annual true-up filing, included in Part E, Section 8 page 1 of 1 reflects the total system energy coast in column G and the portion attributable to Minnesota based on the % of MN sales (subject to FCA) to total system sales.

Public
Response to Information Request MN-DOC-34

OTTER TAIL POWER COMPANY
Docket No: E999/AA-17-492

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson, Nancy Campbell and Stephen Collins
Date Received: 09/19/2018
Date Due: 10/01/2018
Date of Response: 10/01/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Please provide the amount of asset-based margins returned to ratepayers via the fuel clause for the FYE17 reporting period, or cite where in the report this information is provided.

Please provide support for the development of the asset-based margins.

Attachments: 2

Attachment 1 to IR MN-DOC-34.pdf
Attachment 2 to IR MN-DOC-34.pdf

Response:

See Part H Section 3 Attachment K (marked s Not Public) in Docket No. E999/AA-17-492 Part H Section 3 of AAA Report for the total asset-based margins. This information is also summarized in Attachment 1 of IR MN-DOC-31 in same docket.

Asset based margins are determined through Otter Tail's internal program developed at the beginning of the MISO market which matches Otter Tail load to Otter Tail's supply stack (generation , PPA's, Market purchases) on a least cost, committed basis. In the event Otter Tail Resources sell excess energy into the MISO market, those asset based sales and associated costs, including fuel (collectively asset-based margins), are accounted for in Otter Tail's Marketing book. All asset-based margins are passed through the fuel clause.

Attachment 1 to IR MN-DOC-34 provides excerpts from the monthly reports generated from OTP's system that provides the detail behind the MISO costs and revenues attributable to OTP generation in excess of those levels necessary to serve retail load and accounted for in the Marketing Book. A summary page is included which reflects the total MISO revenues of $5,160,722.00 and MISO costs of $(559,024.80) as reported in Part H Section 3 Attachment K (marked s Not Public) in Docket No. E999/AA-17-492 Part H Section.

Attachment 2 to IR MN-DOC-34 provides support detail for the associated fuel costs attributable to the Marketing Book sales. Total fuel costs were $(3,775,601.35).

Monthly Allocation Report - Monthly Plus Adjustments July 2016

Operating Dates: 4/1/2005 -- 7/21/2016

Settlement Dates: 6/30/2016 -- 7/28/2016

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	4,895.399	-334.21	4,895.399	-334.21
DA_ASSET_EN	MARKET	5035.0002.0962	4,895.399	120,889.64	0.000	0.00	4,895.399	120,889.64
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	3.34	0.000	-507.57	0.000	-504.23
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	291.57	0.000	0.00	0.000	291.57
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4,895.399	-52.35	4,895.399	-52.35
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	19,250.863	-1,313.16	19,250.863	-1,313.16
RT_ASM_EXE	MARKET	5035.0056.0962	18.900	377.87	-0.226	0.00	18.674	377.87
RT_ASM_NXE	MARKET	5035.0055.0962	17,508.588	408,154.34	-1,724.251	-37,738.18	15,784.337	370,416.16
RT_PV_MWP	MARKET	5035.0042.0962	0.000	822.11	0.000	-4.27	0.000	817.84
RT_RNU	MARKET	5035.0028.0962	0.000	1,092.50	0.000	-5,884.41	0.000	-4,791.91
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	146.80	0.000	-2,065.73	0.000	-1,918.93
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	15,476.54	0.000	0.00	0.000	15,476.54
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	19,250.863	-206.03	19,250.863	-206.03

Monthly Allocation Report - Monthly Plus Adjustments August 2016

Operating Dates: 4/1/2005 -- 8/23/2016

Settlement Dates: 7/29/2016 -- 8/30/2016

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	4,595.244	-252.26	4,595.244	-252.26
DA_ASSET_EN	MARKET	5035.0002.0962	4,595.244	139,781.73	0.000	0.00	4,595.244	139,781.73
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	15.09	0.000	-299.13	0.000	-284.04
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	525.75	0.000	0.00	0.000	525.75
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4,595.244	-47.24	4,595.244	-47.24
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	12,204.443	-697.03	12,204.443	-697.03
RT_ASM_EXE	MARKET	5035.0056.0962	36.772	486.15	0.000	0.00	36.772	486.15
RT_ASM_NXE	MARKET	5035.0055.0962	10,511.248	278,154.16	-1,606.077	-28,434.30	8,905.171	249,719.86
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,791.72	0.000	-13.41	0.000	1,778.31
RT_RNU	MARKET	5035.0028.0962	0.000	2,005.61	0.000	-5,518.28	0.000	-3,512.67
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	195.47	0.000	-824.27	0.000	-628.80
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	6,288.70	0.000	0.00	0.000	6,288.70
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	12,204.443	-125.73	12,204.443	-125.73

Monthly Allocation Report - Monthly Plus Adjustments September 2016

Operating Dates: 4/1/2005 -- 9/22/2016

Settlement Dates: 8/31/2016 -- 9/29/2016

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	12,062.013	-882.58	12,062.013	-882.58
DA_ASSET_EN	MARKET	5035.0002.0962	12,062.013	354,088.31	0.000	0.00	12,062.013	354,088.31
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	74.35	0.000	-873.62	0.000	-799.27
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	1,566.08	0.000	0.00	0.000	1,566.08
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	12,062.013	-156.78	12,062.013	-156.78
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	23,137.278	-1,732.48	23,137.278	-1,732.48
RT_ASM_EXE	MARKET	5035.0056.0962	3.499	6.37	0.000	0.00	3.499	6.37
RT_ASM_NXE	MARKET	5035.0055.0962	18,435.127	367,045.11	-3,948.018	-81,952.85	14,487.109	285,092.26
RT_MISC	MARKET	5035.0025.0962	0.000	0.00	0.000	-0.01	0.000	-0.01
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,632.24	0.000	0.00	0.000	1,632.24
RT_RNU	MARKET	5035.0028.0962	0.000	2,975.33	0.000	-2,920.36	0.000	54.97
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	149.75	0.000	-3,007.39	0.000	-2,857.64
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	72,721.75	0.000	0.00	0.000	72,721.75
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	23,137.278	-300.75	23,137.278	-300.75

Monthly Allocation Report - Monthly Plus Adjustments October 2016

Operating Dates: 4/1/2005 -- 10/23/2016

Settlement Dates: 9/30/2016 -- 10/30/2016

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	1,134.215	-81.28	1,134.215	-81.28
DA_ASSET_EN	MARKET	5035.0002.0962	1,134.215	28,293.15	0.000	0.00	1,134.215	28,293.15
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	27.85	0.000	-400.66	0.000	-372.81
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	170.06	0.000	0.00	0.000	170.06
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	1,134.215	-22.51	1,134.215	-22.51
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	12,916.106	-991.95	12,916.106	-991.95
RT_ASM_NXE	MARKET	5035.0055.0962	12,715.270	195,044.20	-200.836	-4,434.47	12,514.434	190,609.73
RT_PV_MWP	MARKET	5035.0042.0962	0.000	722.85	0.000	0.00	0.000	722.85
RT_RNU	MARKET	5035.0028.0962	0.000	1,792.12	0.000	-3,778.25	0.000	-1,986.13
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	203.71	0.000	-691.40	0.000	-487.69
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	3,455.80	0.000	0.00	0.000	3,455.80
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	12,916.106	-178.21	12,916.106	-178.21

Monthly Allocation Report - Monthly Plus Adjustments November 2016

Operating Dates: 4/1/2005 -- 11/22/2016

Settlement Dates: 10/31/2016 -- 11/29/2016

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	6,723.789	-488.74	6,723.789	-488.74
DA_ASSET_EN	MARKET	5035.0002.0962	6,723.789	161,028.97	0.000	0.00	6,723.789	161,028.97
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	2.01	0.000	-478.75	0.000	-476.74
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	48.45	0.000	0.00	0.000	48.45
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	6,723.789	-92.45	6,723.789	-92.45
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	16,470.842	-1,198.32	16,470.842	-1,198.32
RT_ASM_EXE	MARKET	5035.0056.0962	45.842	809.52	0.000	0.00	45.842	809.52
RT_ASM_NXE	MARKET	5035.0055.0962	12,207.040	243,911.91	-4,218.256	-71,320.58	7,988.784	172,591.33
RT_PV_MWP	MARKET	5035.0042.0962	0.000	987.60	0.000	0.00	0.000	987.60
RT_RNU	MARKET	5035.0028.0962	0.000	783.63	0.000	-3,926.44	0.000	-3,142.81
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	39.20	0.000	-979.13	0.000	-939.93
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	13,909.28	0.000	0.00	0.000	13,909.28
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	16,470.842	-225.65	16,470.842	-225.65

Monthly Allocation Report - Monthly Plus Adjustments December 2016

Operating Dates: 4/1/2005 -- 12/26/2016

Settlement Dates: 11/30/2016 -- 1/2/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	2,010.400	-150.31	2,010.400	-150.31
DA_ASSET_EN	MARKET	5035.0002.0962	2,010.400	48,269.43	0.000	0.00	2,010.400	48,269.43
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	16.15	0.000	-798.09	0.000	-781.94
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	4.24	0.000	0.00	0.000	4.24
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	2,010.400	-26.58	2,010.400	-26.58
RT_ADMIN	MARKET	5035.0018.0962	0.000	20.55	18,936.589	-1,431.85	18,936.589	-1,411.30
RT_ASM_EXE	MARKET	5035.0056.0962	4.067	89.50	0.000	0.00	4.067	89.50
RT_ASM_NXE	MARKET	5035.0055.0962	17,994.849	476,145.89	-937.977	-17,787.37	17,056.872	458,358.52
RT_MISC	MARKET	5035.0025.0962	0.000	0.00	0.000	-9.59	0.000	-9.59
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,361.09	0.000	-0.19	0.000	1,360.90
RT_RNU	MARKET	5035.0028.0962	0.000	1,326.04	0.000	-3,677.61	0.000	-2,351.57
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	45.52	0.000	-1,834.17	0.000	-1,788.65
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	15,901.47	0.000	0.00	0.000	15,901.47
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	3.96	18,936.589	-247.13	18,936.589	-243.17

Monthly Allocation Report - Monthly Plus Adjustments January 2017

Operating Dates: 4/1/2005 -- 1/23/2017

Settlement Dates: 1/3/2017 -- 1/30/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.02	0.000	-429.37	0.000	-429.35
RT_ADMIN	MARKET	5035.0018.0962	0.000	42.86	15,935.044	-1,123.31	15,935.044	-1,080.45
RT_ASM_EXE	MARKET	5035.0056.0962	7.963	130.15	0.000	0.00	7.963	130.15
RT_ASM_NXE	MARKET	5035.0055.0962	15,922.615	349,364.84	-4.814	-6,705.83	15,917.801	342,659.01
RT_PV_MWP	MARKET	5035.0042.0962	0.000	887.29	0.000	-0.27	0.000	887.02
RT_RNU	MARKET	5035.0028.0962	0.000	918.90	0.000	-1,252.55	0.000	-333.65
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	2.32	0.000	-903.56	0.000	-901.24
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	5,293.18	0.000	0.00	0.000	5,293.18
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	8.00	15,935.044	-196.54	15,935.044	-188.54

Monthly Allocation Report - Monthly Plus Adjustments February 2017

Operating Dates: 4/1/2005 -- 2/20/2017

Settlement Dates: 1/31/2017 -- 2/27/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	1,935.192	-126.34	1,935.192	-126.34
DA_ASSET_EN	MARKET	5035.0002.0962	1,935.192	52,025.51	0.000	0.00	1,935.192	52,025.51
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	22.49	0.000	-71.75	0.000	-49.26
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	1,935.192	-24.42	1,935.192	-24.42
RT_ADMIN	MARKET	5035.0018.0962	0.000	257.81	8,217.024	-539.62	8,217.024	-281.81
RT_ASM_EXE	MARKET	5035.0056.0962	3.319	57.03	0.000	0.00	3.319	57.03
RT_ASM_NXE	MARKET	5035.0055.0962	6,877.974	139,358.57	-1,338.989	-28,090.15	5,538.985	111,268.42
RT_PV_MWP	MARKET	5035.0042.0962	0.000	225.39	0.000	-0.26	0.000	225.13
RT_RNU	MARKET	5035.0028.0962	0.000	287.05	0.000	-2,205.18	0.000	-1,918.13
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	60.39	0.000	-90.49	0.000	-30.10
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	3,855.40	0.000	0.00	0.000	3,855.40
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	46.22	8,217.024	-102.39	8,217.024	-56.17

Monthly Allocation Report - Monthly Plus Adjustments March 2017

Operating Dates: 4/1/2005 -- 3/23/2017

Settlement Dates: 2/28/2017 -- 3/30/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	950.438	-84.71	950.438	-84.71
DA_ASSET_EN	MARKET	5035.0002.0962	950.438	27,548.45	0.000	0.00	950.438	27,548.45
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	9.31	0.000	-300.52	0.000	-291.21
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	950.438	-12.49	950.438	-12.49
RT_ADMIN	MARKET	5035.0018.0962	0.000	616.59	14,433.590	-1,205.72	14,433.590	-589.13
RT_ASM_EXE	MARKET	5035.0056.0962	60.695	1,099.74	-18.422	-240.59	42.273	859.15
RT_ASM_NXE	MARKET	5035.0055.0962	13,772.479	266,340.27	-655.656	-14,380.48	13,116.823	251,959.79
RT_PV_MWP	MARKET	5035.0042.0962	0.000	975.31	0.000	-44.29	0.000	931.02
RT_RNU	MARKET	5035.0028.0962	0.000	607.26	0.000	-2,792.22	0.000	-2,184.96
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	49.13	0.000	-301.76	0.000	-252.63
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	4,459.88	0.000	-0.04	0.000	4,459.84
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	110.56	14,433.590	-187.18	14,433.590	-76.62

Monthly Allocation Report - Monthly Plus Adjustments April 2017

Operating Dates: 4/1/2005 -- 4/20/2017

Settlement Dates: 3/31/2017 -- 4/27/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	2,632.548	-211.51	2,632.548	-211.51
DA_ASSET_EN	MARKET	5035.0002.0962	2,632.548	67,903.52	0.000	0.00	2,632.548	67,903.52
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.07	0.000	-383.27	0.000	-383.20
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	2,632.548	-35.84	2,632.548	-35.84
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	11,452.097	-964.99	11,452.097	-964.99
RT_ASM_EXE	MARKET	5035.0056.0962	5.598	144.90	0.000	0.00	5.598	144.90
RT_ASM_NXE	MARKET	5035.0055.0962	10,099.426	201,457.86	-1,265.071	-27,883.04	8,834.355	173,574.82
RT_PV_MWP	MARKET	5035.0042.0962	0.000	343.94	0.000	0.00	0.000	343.94
RT_RNU	MARKET	5035.0028.0962	0.000	869.29	0.000	-2,689.47	0.000	-1,820.18
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	16.70	0.000	-599.16	0.000	-582.46
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	1,971.88	0.000	0.00	0.000	1,971.88
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	11,452.097	-154.09	11,452.097	-154.09

Monthly Allocation Report - Monthly Plus Adjustments May 2017

Operating Dates: 4/1/2005 -- 5/23/2017

Settlement Dates: 4/28/2017 -- 5/30/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	7,775.972	-616.56	7,775.972	-616.56
DA_ASSET_EN	MARKET	5035.0002.0962	7,775.972	198,490.96	0.000	0.00	7,775.972	198,490.96
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.15	0.000	-430.03	0.000	-429.88
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	7,775.972	-104.11	7,775.972	-104.11
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	15,055.388	-1,193.71	15,055.388	-1,193.71
RT_ASM_EXE	MARKET	5035.0056.0962	4.585	87.12	0.000	0.00	4.585	87.12
RT_ASM_NXE	MARKET	5035.0055.0962	10,652.659	261,226.11	-4,398.144	-79,409.81	6,254.515	181,816.30
RT_PV_MWP	MARKET	5035.0042.0962	0.000	818.91	0.000	0.00	0.000	818.91
RT_RNU	MARKET	5035.0028.0962	0.000	953.60	0.000	-2,939.05	0.000	-1,985.45
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	5.60	0.000	-412.75	0.000	-407.15
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	10,351.44	0.000	0.00	0.000	10,351.44
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	15,055.388	-201.96	15,055.388	-201.96

Monthly Allocation Report - Monthly Plus Adjustments June 2017

Operating Dates: 4/1/2005 -- 6/22/2017

Settlement Dates: 5/31/2017 -- 6/29/2017

Charge Type	Portfolio	Account Cd	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	7,620.257	-580.55	7,620.257	-580.55
DA_ASSET_EN	MARKET	5035.0002.0962	7,620.257	208,556.30	0.000	0.00	7,620.257	208,556.30
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.34	0.000	-418.85	0.000	-418.51
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	772.48	0.000	0.00	0.000	772.48
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	7,620.257	-91.42	7,620.257	-91.42
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	19,028.950	-1,448.95	19,028.950	-1,448.95
RT_ASM_EXE	MARKET	5035.0056.0962	50.681	1,115.08	0.000	0.00	50.681	1,115.08
RT_ASM_NXE	MARKET	5035.0055.0962	15,293.634	371,467.11	-3,731.847	-79,351.03	11,561.787	292,116.08
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,270.29	0.000	0.00	0.000	1,270.29
RT_RNU	MARKET	5035.0028.0962	0.000	2,005.88	0.000	-4,648.22	0.000	-2,642.34
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	14.45	0.000	-606.44	0.000	-591.99
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	5,045.56	0.000	-613.95	0.000	4,431.61
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.01	19,028.950	-227.95	19,028.950	-227.94

Summary of Allocation Reports - Monthly Plus Adjustments July 2016 - June 2017

Operating Dates: 4/1/2005 -- 6/22/2017

Settlement Dates: 6/30/2016 -- 6/29/2017

Charge Type	Portfolio	Account Cd		MW Rev	Dollar Rev	MW Cost	Dollar Cost
DA_ADMIN	MARKET	5035.0001.0962		0	$0.00		($3,809.05)
DA_ASSET_EN	MARKET	5035.0002.0962		52,335	$1,406,875.97		$0.00
DA_RSG_DIST	MARKET	5035.0010.0962		0	$171.17		($5,391.61)
DA_RSG_MWP	MARKET	5035.0011.0962		0	$3,378.63		$0.00
DA_SCHD_24_ALC	MARKET	5035.0033.0962		0	$0.00		($666.19)
RT_ADMIN	MARKET	5035.0018.0962		0	$937.81		($13,841.09)
RT_MISC	MARKET	5035.0025.0962		0	$0.00		($9.60)
RT_ASM_EXE	MARKET	5035.0056.0962		242	$4,403.43	(19)	($240.59)
RT_ASM_NXE	MARKET	5035.0055.0962		161,991	$3,557,670.37	(24,030)	($477,488.09)
RT_PV_MWP	MARKET	5035.0042.0962		0	$11,838.74		($62.69)
RT_RNU	MARKET	5035.0028.0962		0	$15,617.21		($42,232.04)
RT_RSG_DIST1	MARKET	5035.0029.0962			$929.04		($12,316.25)
RT_RSG_MWP	MARKET	5035.0030.0962		0	$158,730.88		($613.99)
RT_SCHD_24_ALC	MARKET	5035.0034.0962		0	$168.75		($2,353.61)
Totals				214,568	$5,160,722.00	(24,049)	($559,024.80)

Marketing Book Costs - Monthly July 2016

Operating Dates: 6/23/2016 -- 7/21/2016

Settlement Dates: 6/30/2016 -- 7/28/2016

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	3,828.838	$88,166.26	-$74,383.40	$13,782.86
	Real Time	11,739.905	$273,445.48	-$231,466.26	$41,979.22
	Total:	**15,568.743**	**$361,611.74**	**-$305,849.66**	**$55,762.08**
OTP.COYOT1	Day Ahead	205.767	$2,914.30	-$1,962.54	$951.76
	Real Time	1,952.679	$33,422.44	-$19,053.80	$14,368.64
	Total:	**2,158.446**	**$36,336.74**	**-$21,016.34**	**$15,320.40**
OTP.HOOTL2	Day Ahead	49.001	$1,440.88	-$1,327.93	$112.95
	Real Time	324.265	$7,201.62	-$8,787.56	-$1,585.94
	Total:	**373.266**	**$8,642.50**	**-$10,115.49**	**-$1,472.99**
OTP.HOOTL3	Day Ahead	315.776	$10,229.72	-$8,702.79	$1,526.93
	Real Time	-71.966	-$4,710.91	$1,983.40	-$2,727.51
	Total:	**243.810**	**$5,518.81**	**-$6,719.39**	**-$1,200.58**
OTP.SLWAYO1	Day Ahead	496.017	$18,138.48	-$14,114.47	$4,024.01
	Real Time	1,858.128	$61,473.09	-$50,572.13	$10,900.96
	Total:	**2,354.145**	**$79,611.57**	**-$64,686.60**	**$14,924.97**
Day Ahead	**Total**	**4,895.399**	**$120,889.64**	**-$100,491.13**	**$20,398.51**
Real Time	**Total**	**15,803.011**	**$370,831.72**	**-$307,896.35**	**$62,935.37**
Margins	**Total**	**20,698.410**	**$491,721.36**	**-$408,387.48**	**$83,333.88**

Marketing Book Costs - Monthly August 2016

Operating Dates: 7/22/2016 -- 8/23/2016

Settlement Dates: 7/29/2016 -- 8/30/2016

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	2,366.458	$66,590.11	-$50,866.40	$15,723.71
	Real Time	6,212.525	$142,366.43	-$133,614.85	$8,751.58
	Total:	**8,578.983**	**$208,956.54**	**-$184,481.25**	**$24,475.29**
OTP.COYOT1	Day Ahead	393.919	$6,401.18	-$4,334.28	$2,066.90
	Real Time	1,048.802	$36,728.65	-$11,537.74	$25,190.91
	Total:	**1,442.721**	**$43,129.83**	**-$15,872.02**	**$27,257.81**
OTP.HETLA	Day Ahead	47.000	$1,554.55	-$1,368.23	$186.32
	Real Time	-11.385	-$467.41	$467.41	$0.00
	Total:	**35.615**	**$1,087.14**	**-$900.82**	**$186.32**
OTP.HOOTL2	Day Ahead	24.000	$823.92	-$650.40	$173.52
	Real Time	106.181	$2,612.42	-$2,877.50	-$265.08
	Total:	**130.181**	**$3,436.34**	**-$3,527.90**	**-$91.56**
OTP.HOOTL3	Day Ahead	727.014	$25,683.67	-$20,036.52	$5,647.15
	Real Time	606.624	$20,845.75	-$16,718.57	$4,127.18
	Total:	**1,333.638**	**$46,529.42**	**-$36,755.09**	**$9,774.33**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.867	$32.82	-$32.82	$0.00
	Total:	**0.867**	**$32.82**	**-$32.82**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	35.936	$1,383.77	-$1,383.77	$0.00
	Total:	**35.936**	**$1,383.77**	**-$1,383.77**	**$0.00**
OTP.SLWAYO1	Day Ahead	1,036.853	$38,728.30	-$31,056.62	$7,671.68
	Real Time	942.393	$46,895.30	-$24,904.42	$21,990.88
	Total:	**1,979.246**	**$85,623.60**	**-$55,961.04**	**$29,662.56**
Day Ahead	**Total**	**4,595.244**	**$139,781.73**	**-$108,312.45**	**$31,469.28**
Real Time	**Total**	**8,941.943**	**$250,397.73**	**-$190,602.26**	**$59,795.47**
Margins	**Total**	**13,537.187**	**$390,179.46**	**-$298,914.71**	**$91,264.75**

Marketing Book Costs - Monthly September 2016

Operating Dates: 8/24/2016 -- 9/22/2016

Settlement Dates: 8/31/2016 -- 9/29/2016

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	7,980.501	$213,992.32	-$170,676.13	$43,316.19
	Real Time	6,896.559	$135,546.77	-$147,453.42	-$11,906.65
	Total:	**14,877.060**	**$349,539.09**	**-$318,129.55**	**$31,409.54**
OTP.COYOT1	Day Ahead	723.271	$11,453.49	-$7,771.26	$3,682.23
	Real Time	6,108.195	$99,399.24	-$66,794.16	$32,605.08
	Total:	**6,831.466**	**$110,852.73**	**-$74,565.42**	**$36,287.31**
OTP.HOOTL2	Day Ahead	328.963	$12,435.56	-$8,747.12	$3,688.44
	Real Time	9.331	-$1,005.23	-$248.10	-$1,253.33
	Total:	**338.294**	**$11,430.33**	**-$8,995.22**	**$2,435.11**
OTP.HOOTL3	Day Ahead	1,352.147	$50,138.72	-$38,609.47	$11,529.25
	Real Time	197.170	$4,876.87	-$5,673.85	-$796.98
	Total:	**1,549.317**	**$55,015.59**	**-$44,283.32**	**$10,732.27**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	47.701	$1,792.75	-$25,778.18	-$23,985.43
	Total:	**47.701**	**$1,792.75**	**-$25,778.18**	**-$23,985.43**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	48.984	$1,830.65	-$25,709.43	-$23,878.78
	Total:	**48.984**	**$1,830.65**	**-$25,709.43**	**-$23,878.78**
OTP.SLWAYO1	Day Ahead	1,677.131	$66,068.22	-$48,230.03	$17,838.19
	Real Time	1,182.668	$42,715.77	-$32,373.65	$10,342.12
	Total:	**2,859.799**	**$108,783.99**	**-$80,603.68**	**$28,180.31**
Day Ahead	**Total**	**12,062.013**	**$354,088.31**	**-$274,034.01**	**$80,054.30**
Real Time	**Total**	**14,490.608**	**$285,156.82**	**-$304,030.79**	**-$18,873.97**
Margins	**Total**	**26,552.621**	**$639,245.13**	**-$578,064.80**	**$61,180.33**

Marketing Book Costs - Monthly October 2016

Operating Dates: 9/23/2016 -- 10/23/2016

Settlement Dates: 9/30/2016 -- 10/30/2016

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2,854.852	$44,380.25	-$61,065.29	-$16,685.04
	Total:	**2,854.852**	**$44,380.25**	**-$61,065.29**	**-$16,685.04**
OTP.COYOT1	Day Ahead	795.138	$15,197.12	-$8,508.45	$6,688.67
	Real Time	8,204.175	$101,494.62	-$89,293.62	$12,201.00
	Total:	**8,999.313**	**$116,691.74**	**-$97,802.07**	**$18,889.67**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	18.345	$581.04	-$581.04	$0.00
	Total:	**18.345**	**$581.04**	**-$581.04**	**$0.00**
OTP.HOOTL2	Day Ahead	20.000	$567.40	-$557.80	$9.60
	Real Time	202.998	$6,106.45	-$5,661.60	$444.85
	Total:	**222.998**	**$6,673.85**	**-$6,219.40**	**$454.45**
OTP.HOOTL3	Day Ahead	111.730	$4,405.39	-$3,207.77	$1,197.62
	Real Time	665.099	$15,859.32	-$19,094.99	-$3,235.67
	Total:	**776.829**	**$20,264.71**	**-$22,302.76**	**-$2,038.05**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	17.982	$345.25	-$345.25	$0.00
	Total:	**17.982**	**$345.25**	**-$345.25**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	9.706	$262.19	-$262.19	$0.00
	Total:	**9.706**	**$262.19**	**-$262.19**	**$0.00**
OTP.SLWAYO1	Day Ahead	207.347	$8,123.24	-$6,775.70	$1,347.54
	Real Time	541.277	$21,580.61	-$17,736.56	$3,844.05
	Total:	**748.624**	**$29,703.85**	**-$24,512.26**	**$5,191.59**
Day Ahead	**Total**	**1,134.215**	**$28,293.15**	**-$19,049.72**	**$9,243.43**
Real Time	**Total**	**12,514.434**	**$190,609.73**	**-$194,040.54**	**-$3,430.81**
Margins	**Total**	**13,648.649**	**$218,902.88**	**-$213,090.26**	**$5,812.62**

Marketing Book Costs - Monthly   November 2016

Operating Dates: 10/24/2016 -- 11/22/2016

Settlement Dates: 10/31/2016 -- 11/29/2016

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	6,202.142	$149,430.51	-$125,221.31	$24,209.20
	Real Time	1,753.554	$51,046.10	-$35,404.22	$15,641.88
	Total:	**7,955.696**	**$200,476.61**	**-$160,625.53**	**$39,851.08**
OTP.COYOT1	Day Ahead	406.062	$7,872.37	-$4,690.00	$3,182.37
	Real Time	3,861.872	$67,300.44	-$44,604.61	$22,695.83
	Total:	**4,267.934**	**$75,172.81**	**-$49,294.61**	**$25,878.20**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	36.746	$992.51	-$992.51	$0.00
	Total:	**36.746**	**$992.51**	**-$992.51**	**$0.00**
OTP.HOOTL2	Day Ahead	51.313	$1,554.00	-$1,431.12	$122.88
	Real Time	47.341	$543.03	-$1,320.35	-$777.32
	Total:	**98.654**	**$2,097.03**	**-$2,751.47**	**-$654.44**
OTP.HOOTL3	Day Ahead	44.000	$1,369.72	-$1,263.24	$106.48
	Real Time	1,366.163	$25,535.75	-$39,222.54	-$13,686.79
	Total:	**1,410.163**	**$26,905.47**	**-$40,485.78**	**-$13,580.31**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	9.802	$215.79	-$215.79	$0.00
	Total:	**9.802**	**$215.79**	**-$215.79**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	15.202	$299.36	-$299.36	$0.00
	Total:	**15.202**	**$299.36**	**-$299.36**	**$0.00**
OTP.SLWAYO1	Day Ahead	20.272	$802.37	-$525.04	$277.33
	Real Time	943.946	$27,536.40	-$29,194.94	-$1,658.54
	Total:	**964.218**	**$28,338.77**	**-$29,719.98**	**-$1,381.21**
Day Ahead	**Total**	**6,723.789**	**$161,028.97**	**-$133,130.71**	**$27,898.26**
Real Time	**Total**	**8,034.626**	**$173,469.38**	**-$151,254.32**	**$22,215.06**
Margins	**Total**	**14,758.415**	**$334,498.35**	**-$284,385.03**	**$50,113.32**

Marketing Book Costs - Monthly December 2016

Operating Dates: 11/23/2016 -- 12/26/2016

Settlement Dates: 11/30/2016 -- 1/2/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,748.047	$39,665.30	-$34,829.31	$4,835.99
	Real Time	9,823.113	$244,444.86	-$199,805.77	$44,639.09
	Total:	**11,571.160**	**$284,110.16**	**-$234,635.08**	**$49,475.08**
OTP.COYOT1	Day Ahead	36.496	$810.58	-$338.68	$471.90
	Real Time	4,029.318	$80,754.28	-$39,854.16	$40,900.12
	Total:	**4,065.814**	**$81,564.86**	**-$40,192.84**	**$41,372.02**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	56.869	$967.84	-$967.84	$0.00
	Total:	**56.869**	**$967.84**	**-$967.84**	**$0.00**
OTP.HOOTL2	Day Ahead	81.579	$2,644.31	-$2,237.25	$407.06
	Real Time	497.678	$16,404.04	-$13,647.33	$2,756.71
	Total:	**579.257**	**$19,048.35**	**-$15,884.58**	**$3,163.77**
OTP.HOOTL3	Day Ahead	67.247	$2,412.26	-$1,968.32	$443.94
	Real Time	580.556	$19,624.94	-$16,618.31	$3,006.63
	Total:	**647.803**	**$22,037.20**	**-$18,586.63**	**$3,450.57**
OTP.SLWAYO1	Day Ahead	77.031	$2,736.98	-$1,901.90	$835.08
	Real Time	2,069.743	$96,171.99	-$76,124.06	$20,047.93
	Total:	**2,146.774**	**$98,908.97**	**-$78,025.96**	**$20,883.01**
Day Ahead	**Total**	**2,010.400**	**$48,269.43**	**-$41,275.46**	**$6,993.97**
Real Time	**Total**	**17,057.277**	**$458,367.95**	**-$347,017.47**	**$111,350.48**
Margins	**Total**	**19,067.677**	**$506,637.38**	**-$388,292.93**	**$118,344.45**

Marketing Book Costs - Monthly Adjustments December 2016

Operating Dates: 4/1/2005 -- 11/22/2016

Settlement Dates: 11/30/2016 -- 1/2/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.718	$61.26	-$54.77	$6.49
	Total:	**2.718**	**$61.26**	**-$54.77**	**$6.49**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.944	$18.77	-$10.92	$7.85
	Total:	**0.944**	**$18.77**	**-$10.92**	**$7.85**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**3.662**	**$80.03**	**-$65.69**	**$14.34**
Margins	**Total**	**3.662**	**$80.03**	**-$65.69**	**$14.34**

Marketing Book Costs - Monthly January 2017

Operating Dates: 12/27/2016 -- 1/23/2017

Settlement Dates: 1/3/2017 -- 1/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	8,744.588	$195,486.30	-$182,327.91	$13,158.39
	Total:	**8,744.588**	**$195,486.30**	**-$182,327.91**	**$13,158.39**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	5,893.441	$98,364.34	-$64,919.43	$33,444.91
	Total:	**5,893.441**	**$98,364.34**	**-$64,919.43**	**$33,444.91**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	393.465	$10,768.15	-$10,812.93	-$44.78
	Total:	**393.465**	**$10,768.15**	**-$10,812.93**	**-$44.78**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	417.579	$10,716.51	-$11,654.63	-$938.12
	Total:	**417.579**	**$10,716.51**	**-$11,654.63**	**-$938.12**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	476.624	$27,464.10	-$17,783.50	$9,680.60
	Total:	**476.624**	**$27,464.10**	**-$17,783.50**	**$9,680.60**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**15,925.697**	**$342,799.40**	**-$287,498.40**	**$55,301.00**
Margins	**Total**	**15,925.697**	**$342,799.40**	**-$287,498.40**	**$55,301.00**

Marketing Book Costs - Monthly Adjustments January 2017

Operating Dates: 4/1/2005 -- 12/26/2016

Settlement Dates: 1/3/2017 -- 1/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.067	-$0.11	-$1.73	-$1.84
	Total:	**0.067**	**-$0.11**	**-$1.73**	**-$1.84**

Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.067**	**-$0.11**	**-$1.73**	**-$1.84**
Margins	**Total**	**0.067**	**-$0.11**	**-$1.73**	**-$1.84**

Marketing Book Costs - Monthly   February 2017

Operating Dates: 1/24/2017 -- 2/20/2017

Settlement Dates: 1/31/2017 -- 2/27/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,518.335	$38,500.40	-$33,674.31	$4,826.09
	Real Time	2,469.825	$54,832.30	-$53,478.87	$1,353.43
	Total:	**3,988.160**	**$93,332.70**	**-$87,153.18**	**$6,179.52**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2,648.610	$46,538.60	-$31,084.75	$15,453.85
	Total:	**2,648.610**	**$46,538.60**	**-$31,084.75**	**$15,453.85**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	58.179	$1,308.29	-$1,616.78	-$308.49
	Total:	**58.179**	**$1,308.29**	**-$1,616.78**	**-$308.49**
OTP.HOOTL3	Day Ahead	383.340	$12,071.16	-$10,944.36	$1,126.80
	Real Time	210.411	$4,203.36	-$6,007.20	-$1,803.84
	Total:	**593.751**	**$16,274.52**	**-$16,951.56**	**-$677.04**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.287	$5.88	-$5.88	$0.00
	Total:	**0.287**	**$5.88**	**-$5.88**	**$0.00**
OTP.JAMSPK2	Day Ahead	8.000	$188.56	-$152.40	$36.16
	Real Time	-0.452	-$8.54	$8.54	$0.00
	Total:	**7.548**	**$180.02**	**-$143.86**	**$36.16**
OTP.SLWAYO1	Day Ahead	25.517	$1,265.39	-$1,212.06	$53.33
	Real Time	126.515	$3,873.73	-$5,246.13	-$1,372.40
	Total:	**152.032**	**$5,139.12**	**-$6,458.19**	**-$1,319.07**
Day Ahead	**Total**	**1,935.192**	**$52,025.51**	**-$45,983.13**	**$6,042.38**
Real Time	**Total**	**5,513.375**	**$110,753.62**	**-$97,431.07**	**$13,322.55**
Margins	**Total**	**7,448.567**	**$162,779.13**	**-$143,414.20**	**$19,364.93**

Marketing Book Costs - Monthly Adjustments   February 2017

Operating Dates: 4/1/2005 -- 1/23/2017

Settlement Dates: 1/31/2017 -- 2/27/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	6.772	$134.96	-$146.08	-$11.12
	Total:	**6.772**	**$134.96**	**-$146.08**	**-$11.12**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.812	$48.01	-$30.73	$17.28
	Total:	**2.812**	**$48.01**	**-$30.73**	**$17.28**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	19.345	$388.86	-$537.61	-$148.75
	Total:	**19.345**	**$388.86**	**-$537.61**	**-$148.75**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**28.929**	**$571.83**	**-$714.42**	**-$142.59**
Margins	**Total**	**28.929**	**$571.83**	**-$714.42**	**-$142.59**

Marketing Book Costs - Monthly March 2017

Operating Dates: 2/21/2017 -- 3/23/2017

Settlement Dates: 2/28/2017 -- 3/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	491.810	$12,984.16	-$10,906.67	$2,077.49
	Real Time	6,529.596	$133,281.14	-$146,074.46	-$12,793.32
	Total:	**7,021.406**	**$146,265.30**	**-$156,981.13**	**-$10,715.83**
OTP.COYOT1	Day Ahead	183.844	$4,045.57	-$2,228.18	$1,817.39
	Real Time	5,414.247	$79,146.87	-$69,004.06	$10,142.81
	Total:	**5,598.091**	**$83,192.44**	**-$71,232.24**	**$11,960.20**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	9.943	$128.23	-$128.23	$0.00
	Total:	**9.943**	**$128.23**	**-$128.23**	**$0.00**
OTP.HOOTL2	Day Ahead	140.455	$4,663.31	-$3,901.84	$761.47
	Real Time	281.015	$7,211.34	-$7,808.17	-$596.83
	Total:	**421.470**	**$11,874.65**	**-$11,710.01**	**$164.64**
OTP.HOOTL3	Day Ahead	5.000	$165.60	-$142.75	$22.85
	Real Time	161.644	$3,624.52	-$4,614.96	-$990.44
	Total:	**166.644**	**$3,790.12**	**-$4,757.71**	**-$967.59**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.368	$7.22	-$7.22	$0.00
	Total:	**0.368**	**$7.22**	**-$7.22**	**$0.00**
OTP.SLWAYO1	Day Ahead	129.329	$5,689.81	-$4,363.49	$1,326.32
	Real Time	621.606	$25,953.64	-$19,098.74	$6,854.90
	Total:	**750.935**	**$31,643.45**	**-$23,462.23**	**$8,181.22**
Day Ahead	**Total**	**950.438**	**$27,548.45**	**-$21,542.93**	**$6,005.52**
Real Time	**Total**	**13,018.419**	**$249,352.96**	**-$246,735.84**	**$2,617.12**
Margins	**Total**	**13,968.857**	**$276,901.41**	**-$268,278.77**	**$8,622.64**

Marketing Book Costs - Monthly Adjustments March 2017

Operating Dates: 4/1/2005 -- 2/20/2017

Settlement Dates: 2/28/2017 -- 3/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	140.639	$3,517.97	-$3,859.13	-$341.16
	Total:	**140.639**	**$3,517.97**	**-$3,859.13**	**-$341.16**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.038	$1.10	-$1.99	-$0.89
	Total:	**0.038**	**$1.10**	**-$1.99**	**-$0.89**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**140.677**	**$3,519.07**	**-$3,861.12**	**-$342.05**
Margins	**Total**	**140.677**	**$3,519.07**	**-$3,861.12**	**-$342.05**

Marketing Book Costs - Monthly   April 2017

Operating Dates: 3/24/2017 -- 4/20/2017

Settlement Dates: 3/31/2017 -- 4/27/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,972.392	$52,223.83	-$43,635.22	$8,588.61
	Real Time	4,727.065	$115,534.52	-$104,722.04	$10,812.48
	Total:	**6,699.457**	**$167,758.35**	**-$148,357.26**	**$19,401.09**
OTP.COYOT1	Day Ahead	347.662	$5,575.31	-$4,213.68	$1,361.63
	Real Time	3,323.656	$36,614.61	-$40,222.25	-$3,607.64
	Total:	**3,671.318**	**$42,189.92**	**-$44,435.93**	**-$2,246.01**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	101.116	$3,097.74	-$3,097.74	$0.00
	Total:	**101.116**	**$3,097.74**	**-$3,097.74**	**$0.00**
OTP.HOOTL2	Day Ahead	31.976	$973.80	-$888.30	$85.50
	Real Time	72.380	$2,155.08	-$2,010.75	$144.33
	Total:	**104.356**	**$3,128.88**	**-$2,899.05**	**$229.83**
OTP.HOOTL3	Day Ahead	280.518	$9,130.58	-$8,008.79	$1,121.79
	Real Time	467.344	$12,044.95	-$13,342.66	-$1,297.71
	Total:	**747.862**	**$21,175.53**	**-$21,351.45**	**-$175.92**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	148.392	$4,295.26	-$4,347.94	-$52.68
	Total:	**148.392**	**$4,295.26**	**-$4,347.94**	**-$52.68**
Day Ahead	**Total**	**2,632.548**	**$67,903.52**	**-$56,745.99**	**$11,157.53**
Real Time	**Total**	**8,839.953**	**$173,742.16**	**-$167,743.38**	**$5,998.78**
Margins	**Total**	**11,472.501**	**$241,645.68**	**-$224,489.37**	**$17,156.31**

Marketing Book Costs - Monthly May 2017

Operating Dates: 4/21/2017 -- 5/23/2017

Settlement Dates: 4/28/2017 -- 5/30/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	6,286.033	$164,787.15	-$136,763.30	$28,023.85
	Real Time	2,030.974	$89,966.84	-$43,606.96	$46,359.88
	Total:	**8,317.007**	**$254,753.99**	**-$180,370.26**	**$74,383.73**
OTP.COYOT1	Day Ahead	1,214.292	$24,641.17	-$13,174.47	$11,466.70
	Real Time	2,945.703	$51,790.63	-$32,185.38	$19,605.25
	Total:	**4,159.995**	**$76,431.80**	**-$45,359.85**	**$31,071.95**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.204	$6.34	-$6.34	$0.00
	Total:	**0.204**	**$6.34**	**-$6.34**	**$0.00**
OTP.HOOTL3	Day Ahead	275.647	$9,062.64	-$7,869.72	$1,192.92
	Real Time	307.369	$6,264.32	-$8,775.37	-$2,511.05
	Total:	**583.016**	**$15,326.96**	**-$16,645.09**	**-$1,318.13**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.215	$45.20	-$45.20	$0.00
	Total:	**0.215**	**$45.20**	**-$45.20**	**$0.00**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.242	$44.05	-$44.05	$0.00
	Total:	**1.242**	**$44.05**	**-$44.05**	**$0.00**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	973.393	$33,786.04	-$31,276.55	$2,509.49
	Total:	**973.393**	**$33,786.04**	**-$31,276.55**	**$2,509.49**
Day Ahead	**Total**	**7,775.972**	**$198,490.96**	**-$157,807.49**	**$40,683.47**
Real Time	**Total**	**6,259.100**	**$181,903.42**	**-$115,939.85**	**$65,963.57**
Margins	**Total**	**14,035.072**	**$380,394.38**	**-$273,747.34**	**$106,647.04**

Marketing Book Costs - Monthly June 2017

Operating Dates: 5/24/2017 -- 6/22/2017

Settlement Dates: 5/31/2017 -- 6/29/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	5,142.826	$122,260.40	-$109,841.79	$12,418.61
	Real Time	6,488.802	$153,004.01	-$138,553.43	$14,450.58
	Total:	**11,631.628**	**$275,264.41**	**-$248,395.22**	**$26,869.19**
OTP.COYOT1	Day Ahead	798.456	$16,045.03	-$8,447.67	$7,597.36
	Real Time	2,714.566	$52,579.98	-$29,655.07	$22,924.91
	Total:	**3,513.022**	**$68,625.01**	**-$38,102.74**	**$30,522.27**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	125.550	$2,650.53	-$2,650.53	$0.00
	Total:	**125.550**	**$2,650.53**	**-$2,650.53**	**$0.00**
OTP.HOOTL2	Day Ahead	221.126	$7,376.41	-$6,125.19	$1,251.22
	Real Time	771.668	$28,877.23	-$21,466.78	$7,410.45
	Total:	**992.794**	**$36,253.64**	**-$27,591.97**	**$8,661.67**
OTP.HOOTL3	Day Ahead	430.544	$18,545.59	-$12,158.57	$6,387.02
	Real Time	663.908	$13,300.49	-$18,838.55	-$5,538.06
	Total:	**1,094.452**	**$31,846.08**	**-$30,997.12**	**$848.96**
OTP.JAMSPK1	Day Ahead	8.000	$191.44	-$173.36	$18.08
	Real Time	-1.898	-$41.13	$41.13	$0.00
	Total:	**6.102**	**$150.31**	**-$132.23**	**$18.08**
OTP.JAMSPK2	Day Ahead	6.716	$180.32	-$229.49	-$49.17
	Real Time	-1.225	-$41.86	$41.86	$0.00
	Total:	**5.491**	**$138.46**	**-$187.63**	**-$49.17**
OTP.SLWAYO1	Day Ahead	1,012.589	$43,957.11	-$30,961.30	$12,995.81
	Real Time	851.129	$42,931.54	-$23,377.06	$19,554.48
	Total:	**1,863.718**	**$86,888.65**	**-$54,338.36**	**$32,550.29**
Day Ahead	**Total**	**7,620.257**	**$208,556.30**	**-$167,937.37**	**$40,618.93**
Real Time	**Total**	**11,612.500**	**$293,260.79**	**-$234,458.43**	**$58,802.36**
Margins	**Total**	**19,232.757**	**$501,817.09**	**-$402,395.80**	**$99,421.29**

Marketing Book Costs - Monthly Adjustments June 2017

Operating Dates: 4/1/2005 -- 5/23/2017

Settlement Dates: 5/31/2017 -- 6/29/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.032	-$0.65	$0.70	$0.05
	Total:	**-0.032**	**-$0.65**	**$0.70**	**$0.05**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-0.032**	**-$0.65**	**$0.70**	**$0.05**
Margins	**Total**	**-0.032**	**-$0.65**	**$0.70**	**$0.05**

Marketing Book Costs - Monthly Adjustments July 2016 - June 2017

Operating Dates: 6/23/2016 -- 06/22/2017
Settlement Dates: 6/30/2016 -- 6/29/2017

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	37,537.382	$948,600.44	($790,797.84)	$157,802.60
	Real Time	70,280.816	$1,633,530.57	($1,477,773.63)	$155,756.94
	Total:	**107,818.198**	**$2,582,131.01**	**($2,268,571.47)**	**$313,559.54**
OTP.COYOT1	Day Ahead	5,104.907	$94,956.12	($55,669.21)	$39,286.91
	Real Time	48,149.020	$784,201.48	($538,250.68)	$245,950.80
	Total:	**53,253.927**	**$879,157.60**	**($593,919.89)**	**$285,237.71**
OTP.HETLA	Day Ahead	47.000	$1,554.55	($1,368.23)	$186.32
	Real Time	337.388	$7,956.82	($7,956.82)	$0.00
	Total:	**384.388**	**$9,511.37**	**($9,325.05)**	**$186.32**
OTP.HOOTL2	Day Ahead	948.413	$32,479.59	($25,866.95)	$6,612.64
	Real Time	2,924.485	$86,089.25	($80,654.59)	$5,434.66
	Total:	**3,872.898**	**$118,568.84**	**($106,521.54)**	**$12,047.30**
OTP.HOOTL3	Day Ahead	3,992.963	$143,215.05	($112,912.30)	$30,302.75
	Real Time	5,571.901	$132,185.87	($158,578.23)	($26,392.36)
	Total:	**9,564.864**	**$275,400.92**	**($271,490.53)**	**$3,910.39**
OTP.JAMSPK1	Day Ahead	8.000	$191.44	($173.36)	$18.08
	Real Time	75.324	$2,403.78	($26,389.21)	($23,985.43)
	Total:	**83.324**	**$2,595.22**	**($26,562.57)**	**($23,967.35)**
OTP.JAMSPK2	Day Ahead	14.716	$368.88	($381.89)	($13.01)
	Real Time	109.393	$3,769.62	($27,648.40)	($23,878.78)
	Total:	**124.109**	**$4,138.50**	**($28,030.29)**	**($23,891.79)**
OTP.SLWAYO1	Day Ahead	4,682.086	$185,509.90	($139,140.61)	$46,369.29
	Real Time	10,735.919	$434,678.46	($332,039.40)	$102,639.06
	Total:	**15,418.005**	**$620,188.36**	**($471,180.01)**	**$149,008.35**
Day Ahead	**Total**	**52,335.467**	**$1,406,875.97**	**($1,126,310.39)**	**$280,565.58**
Real Time	**Total**	**138,184.246**	**$3,084,815.85**	**($2,649,290.96)**	**$435,524.89**
Margins	**Total**	**190,519.713**	**$4,491,691.82**	**($3,775,601.35)**	**$716,090.47**

Monthly Allocation Report - Monthly Plus Adjustments July 2016
Operating Dates: 4/1/2005 -- 7/21/2016
Settlement Dates: 6/30/2016 -- 7/28/2016

Charge Type	Portfolio	Account CD	MW Rev	Dollar Rev	MW Cost	Dollar Cost	MW Net	Dollar Net
DA_ADMIN	MARKET	5035.0001.0962	0.000	0.00	4,895.399	(334.21)	4,895.40	(334.21)
DA_ASSET_EN	MARKET	5035.0002.0962	4,895.399	120,889.64	0.000	0.00	4,895.40	120,889.64
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	3.34	0.000	(507.57)	0.00	(504.23)
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	291.57	0.000	0.00	0.00	291.57
DA_SCH_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4,895.399	(52.35)	4,895.40	(52.35)
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	19,250.863	(1,313.16)	19,250.86	(1,313.16)
RT_ASM_EXE	MARKET	5035.0056.0962	18.900	377.87	(0.226)	0.00	18.67	377.87
RT_ASM_NXE	MARKET	5035.0055.0962	17,508.588	408,154.34	(1,724.251)	(37,738.18)	15,784.34	370,416.16
RT_PV_MWP	MARKET	5035.0042.0962	0.000	822.11	0.000	(4.27)	0.00	817.84
RT_RNU	MARKET	5035.0028.0962	0.000	1,092.50	0.000	(5,884.41)	0.00	(4,791.91)
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	146.80	0.000	(2,065.73)	0.00	(1,918.93)
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	15,476.54	0.000	0.00	0.00	15,476.54
RT_SCH_24_ALC	MARKET	5035.0034.0962	0.000	0.00	19,250.863	(206.03)	19,250.86	(206.03)

		Dollar Rev	Dollar Cost	Dollar Net	
Part H Section 3 Attachment K Asset Based Wholesale Line 58		547,254.71	(47,847.53)	499,407.18	Net MISO Asset Based
Attachment 2 to IR MN-DOC-34 Page 1	Part E Section 2 Attachment D Page 5 Line 6			(408,387.48)	Less: Fuel Cost (Intersystem Sales)
Part H Section 3 Attachment K Asset Based Wholesale Line 72				(258.38)	Less: Schedule 24 for Asset Based Sales Does not flow through FCA
Part E Section 2 Attachment D Page 5 Line 7				90,761.32	Total Asset Based Margin