April 15, 2020 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Review of the July 2018-December 2019 Annual Automatic Adjustment Reports**
Docket No. E999/AA-20-171

Dear Mr. Seuffert:

Minnesota Rules 7825.2800 through 7825.2830 requires natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports. To provide further context to these reports, the 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 1984 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 July 2018-December 2019 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (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 AAA Report herein provided.

Sincerely,

/s/ MARK A. JOHNSON	/s/ NANCY CAMPBELL
Public Utilities Analyst Coordinator	Public Utilities Analyst Coordinator

MAJ/NC
Attachments

PUBLIC REVIEW OF THE JULY 2018-DECEMBER 2019 ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. E999/AA-20-171

APRIL 15, 2020

TABLE OF CONTENTS

Section Page

I. OVERVIEW 1

II. FILING REQUIREMENTS 1
A. Minnesota Rules 1
B. Summary of Fuel Cost Projections 3

III. COMPLIANCES 6
A. *In the Matter of a Request for Investigation of Northern States Power Company's Practices Regarding Energy Marketing and the Fuel Clause* in Docket No. E002/CI-00-415 8
B. *In the Matter of a Request by Northern States Power Company, d/b/a Xcel Energy for Commission Approval of Gas Financial Instruments Natural Gas Financial Instruments for Wholesale Electric Transactions* in Docket No. E002/M-01-1953 8
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, ... 9
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 in Docket No. E002/GR-05-1428 10
E. Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (*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). 11
F. 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) 12
G. Plant Outages Contingency Plans (*In the Matter of the Review of the 2008 Annual Automatic Adjustment Reports for All Electric Utilities,* Docket No. E999/AA-08-995) 13

H. 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 14
I. *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 14
J. *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 15
K. *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 15
L. *In the Matter of Xcel Energy's Request for Approval of a Community Solar Garden Program*, Docket No. E002/M-13-867 15
M. 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 16
N. *In the Matter of Xcel Energy's Petition for Approval of an Amendment to the Hennepin Energy Recovery Center Power Purchase Agreement,* Docket No. E002/M-17-532. 17
O. *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Renewable*Connect Pilot Programs,* Docket No. E002/M-15-985. 17
P. *In the Matter of the Petition of Northern States Power Company for Approval to Sell Land and Tanks to Flint Hills Resources Pine Bend, LLC,* Docket No. E002/PA-17-529. 18
Q. *In the Matter of the Petition of Northern States Power Company for Approval to Sell 365 Acres of Sherco Land,* Docket No. E002/PA-17-528. 19
R. *In the Matter of the Petition of Northern States Power Company for Approval of Biomass PPA Termination Cost Recovery, Docket Nos. E002/M-17-530, E002/M-17-531 and E002/M-17-551* 19

IV. TOTAL FUEL COST REVIEW 21
A. Overview 21
B. Minnesota Power 22
C. Otter Tail Power Company 22
D. Xcel Electric 22

V. EFFECTS OF THE MISO DAY 1 MARKETS ON MINNESOTA RATEPAYERS 23
A. Any Amount of MISO Administrative Charge Deferred by MISO for Later Recovery 23
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 23

C. Each Instance Where MISO Directed the Curtailment of a 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 23
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 24
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. 24
F. Conclusions Regarding MISO Day 1 25

VI. EFFECTS OF MISO DAY 2 MARKETS ON MINNESOTA RATEPAYERS 26
A. Background on MISO Day 2 26
B. Overall Effects of MISO Day 2 Market on Utilities and Customers 28
C. Overall Review of MISO Day 2 Charges 29
1. Review of Xcel Electric's MISO Day 2 Charges 29
2. Review of MP's MISO Day 2 Charges 31
3. Review of OTP's MISO Day 2 Charges 33
D. Asset-Based Margin or Wholesale Revenue Review 34
1. Xcel Electric 34
2. MP 35
3. OTP 36
E. Department Involvement in MISO Processes 37
F. Summary of Conclusions Regarding MISO Day 2 Costs and Revenues 38
VII. ANCILLARY SERVICES MARKET (ASM) 38
A. Background 38
B. Xcel Electric 41
C. MP 45
D. OTP 47
VIII. FUEL COSTS AND EFFECTS ON CUSTOMER BILLS 48

IX. RECOMMENDATIONS AND REQUESTS OR ADDITIONAL INFORMATION 49
A. Section II, Filing Requirements 49
B. Section III, Compliance Dockets 51
C. Section IV, Fuel Cost Review 51
D. Recommendations for MISO Day 1 51
E. MISO Day 2 Reporting and Allocations 51
F. Recommendations for Asset Based Margins 51
G. Recommendations for Ancillary Services Market 52

I. OVERVIEW

This document provides the Division of Energy Resources of the Minnesota Department of Commerce's (Department) summary and partial review of the automatic adjustment charges for the July 2018 – December 2019 reporting period, which were filed by three Minnesota electric utilities in compliance with Minnesota Rule 7825.2810 as varied by the Minnesota Public Utilities Commission's (Commission) June 12, 2019 Order in Docket No. E999/CI-03-802.

The Department offers recommendations to the Commission, and requests that the Commission review this information and determine whether the rates charged by electric utilities during this period were reasonable.[1]

The utilities included in this report are:[2]

- 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 three rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[3]

The Department's review focused on whether the electric utilities had, during the AAA period of July 1, 2018 to December 31, 2019, 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] Note: per the Commission's June 12, 2019 Order in Docket No. E999/CI-03-802, utilities will file their proposed rates for 2021 by May 1, 2020, which is the same date that utilities' replies to these comments are due. Comments on proposed rates are due July 1, 2020.
[2] Dakota Electric Association filed its FYE19 AAA report on August 28, 2019 in Docket No. E999/AA-19-402.
[3] 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.[4]

With the exceptions of a few costs that are allocated only to the Minnesota jurisdiction, each reporting utility computed billing adjustments and total fuel costs on a system-wide basis.[5] 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 three reporting electric utilities comply with the Commission's filing requirements, as described in Minnesota Rule 7825.2810, subpart 1.

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, for the 18-month period of July 1, 2018 through December 31, 2019.

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:

---

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

[5] For example, the costs of Xcel's Community Solar Gardens are charged only to Xcel's Minnesota ratepayers. However, beyond these exceptions, in the discussion of allocations throughout this report, the Department notes that the two categories to which total system costs and revenues are allocated are 1) retail customers and 2) 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 of Xcel Electric's Part F, MP's Attachment No. 1 and OTP's Part F, all electric utilities provided the above information in their Auditor Reports. As a result, the Department recommends that the Commission accept Xcel Electric's, MP's and OTP's Auditor Reports.

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

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

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

B. SUMMARY OF FUEL COST PROJECTIONS

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.

The utilities' energy cost projections are summarized below:

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	2020	2021	2022	2023	2024
	[TRADE SECRET DATA HAS BEEN EXCISED]				
(1) MP					
(2) OTP					
(3) Xcel Electric					

(1) Attachment 4 of MP's March 2, 2020 AAA report in Docket No. E999/AA-20-171.
(2) Attachment 14 of OTP's May 1, 2019 Forecast report in Docket No. E017/AA-19-297.
(3) Xcel Electric's April 8, 2020 Supplement in Docket No. E999/AA-20-171.

Table 1.2 Annual and Cumulative Percent Change in Forecasted Energy Costs

$/MWh	2020	2021	2022	2023	2024	2020-2024
(1) MP						
(2) OTP	[TRADE SECRET DATA HAS BEEN EXCISED}					
(3) 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' (IOUs) annual energy 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 2019 energy costs to actual 2019 energy costs.[6]

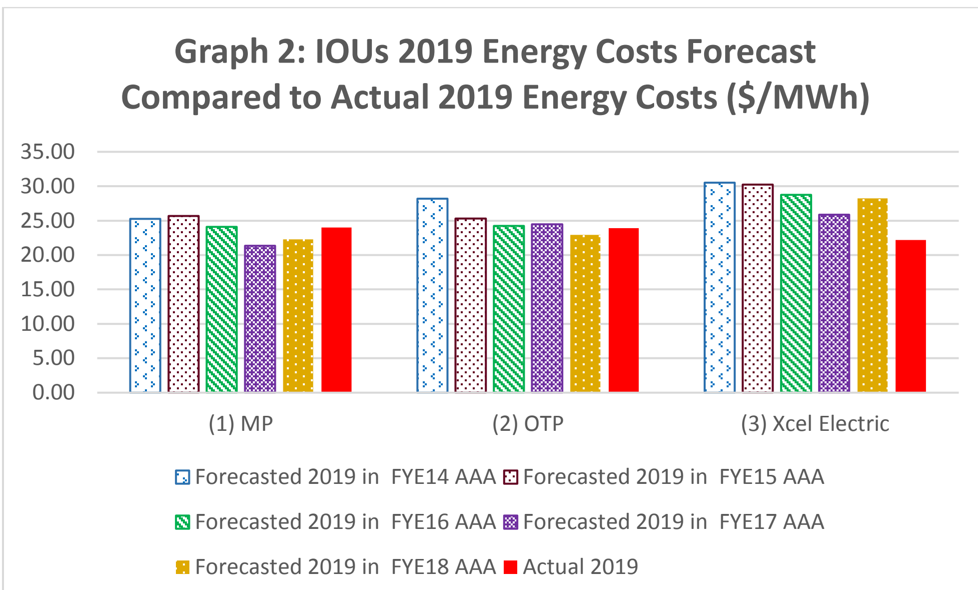


Table 2.1: IOUs' 2019 Energy Cost Forecast Compared to Actual 2019 Energy Costs ($/MWh)

	Forecasted 2019 in FYE14 AAA	Forecasted 2019 in FYE15 AAA	Forecasted 2019 in FYE16 AAA	Forecasted 2019 in FYE17 AAA	Forecasted 2019 in FYE18 AAA	Actual 2019
(1) MP	25.27	25.67	24.08	21.34	22.27	23.98
(2) OTP	28.17	25.32	24.25	24.45	22.94	23.93
(3) Xcel Electric	30.51	30.25	28.74	25.86	28.23	22.18

(1) Attachment 4, page 3 of 3, MP's FYE14-FYE18 AAA reports.
(2) OTP's FYE14-FYE18 AAA reports.
(3) Part G, Section 1, pages 1-5 of 5, Xcel Electric's FYE14-FYE18 AAA reports.

[6] OTP and Xcel Electric's FYE14-FYE18 forecasts for 2019 are calendar year forecasts, while MP's forecast for 2019 is a fiscal year forecast.

As would be expected, the Department notes that the forecasts generally became closer to 2019 actual annual costs, the closer to 2019 the forecasts were made. OTP generally 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 2019 Energy Costs

	Actual 2019 $/MWh	Forecasted 2019 in FYE14 AAA	Forecasted 2019 in FYE15 AAA	Forecasted 2019 in FYE16 AAA	Forecasted 2019 in FYE17 AAA	Forecasted 2019 in FYE18 AAA
MP	23.98	5.4%	7.05%	0.42%	-11.01%	-7.13%
OTP	23.93	17.7%	5.81%	1.34%	2.17%	-4.14%
Xcel Electric	22.18	37.6%	36.38%	29.58%	16.59%	27.28%

III. COMPLIANCES

The Department addresses the following reports in this section.[7]

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 Gas Financial Instruments Natural Gas Financial Instruments for Wholesale Electric Transactions,* Docket No. E002/M-01-1953.

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

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

E. 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).

[7] The Department notes that the analysis of compliances related to the MISO Day 1 market is discussed in Section V of this report, *Effects of the MISO Day 1 Market on Minnesota Ratepayers.* The discussion of the effects of the MISO Day 2 market is discussed in Section VIII of this report, *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

F. 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).

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

H. 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).

I. *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.

J. *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.

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

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

M. 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.

N. *In the Matter of Xcel Energy's Petition for Approval of an Amendment to the Hennepin Energy Recovery Center Power Purchase Agreement,* Docket No. E002/M-17-532.

O. *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Renewable*Connect Pilot Programs,* Docket No. E002/M-15-985.

P. *In the Matter of the Petition of Northern States Power Company for Approval to Sell Land and Tanks to Flint Hills Resources Pine Bend, LLC,* Docket No. E002/PA-17-529.

Q. *In the Matter of the Petition of Northern States Power Company for Approval to Sell 365 Acres of Sherco Land,* Docket No. E002/PA-17-528.

R. *In the Matter of the Petition of Northern States Power Company for Approval of Biomass PPA Termination Cost Recovery, Docket Nos. E002/M-17-530, E002/M-17-531 and E002/M-17-551.*

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 allocations between retail ratepayers and wholesale electric sales was just and reasonable as to retail rates. On April 20, 2001, the OAG stated that a formal investigation was no longer warranted so long as Xcel complies with certain reporting requirements.

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

In Xcel Electric's AAA Report, the monthly generation costs allocated to retail and wholesale customers was provided for 2019.[8] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2019.

The Department reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector, and noted that the information filed by the Company appears to comply with the requirements of the Commission's Order. Xcel's data indicated that for all three months in 2019, 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 lowest cost resources continue to be assigned to retail customers. Based on our review of the 2019 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 2019.

B. IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, D/B/A XCEL ENERGY FOR COMMISSION APPROVAL OF 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. With Commission approval, Xcel Electric proposed

[8] This information was provided in Xcel's AAA Report, Part H, Section 2, Schedule 1.

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 purchased gas adjustment true-up to be filed September 1, 2002, to ensure that the accounting separation is implemented appropriately.

Xcel Electric's AAA Report includes a copy of the prescribed letter by Xcel Electric to its external auditors[9] and a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[10] 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. E999/AA-15-611….
>
> i. Through inspection of a sample of twelve 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 one selection. We did not identify any wholesale electric financial instrument gains or losses recorded in Account 555 or Account 804.

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.

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).

[9] See Part F, Schedule 1 of Xcel Electric's AAA report.
[10] See Part F, Schedule 2 of Xcel Electric's 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. In its April 4, 2006 Order in that docket (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 the 2006 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 AAA Report, the Department reviewed Xcel Electric's wind curtailment data.[11] Curtailment costs have been substantially reduced from their peak during FYE05 from 16.50 percent of the total cost of wind, including curtailments, to 8.3 percent in FYE08 and 1.8 percent in FYE13. While curtailment costs increased substantially to 9.4 percent in FYE14, they were down again at 4.4 percent in FYE15 and 1.28 percent in FYE19.[12]

The Department notes that Xcel Electric's wind curtailment report (Wind Report) indicates that, similar to previous wind reports, most of the curtailment payments are related to MISO directives (curtailment reason code 3).[13]

The Department recommends that the Commission accept Xcel Electric's Wind Report.

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 Department notes that Xcel Electric stated that it "provided details about our plans to manage price risk volatility, including our hedging strategy, in our May 1, 2019 Annual Forecast of Rates filing in Docket No. E002/AA-19-293."[14]

---

[11] Part H, Section 5, Schedule 2 of Xcel Electric's AAA report states that "[t]he Company has typically provided estimates of future potential curtailment payments estimates in the AAA Report. However, going forward, these estimates will be provided in our fuel forecast Petition, including the one that will be filed on May 1, 2020."
[12] Source: Attachment B1 to this report.
[13] Part H, Section 5, Schedule 1, page 4 of 5 of Xcel Electric's AAA report.
[14] Part J, Sections 1-3, page 3 of 3 of Xcel Electric's AAA report.

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. 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."[15] 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."[16] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

In its April 6, 2012 Order in Docket No. E999/AA-10-884 (2012 Order), the Commission required the IOUs to report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by 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.

---

[15] Source: Part H, Sections 1-10, page 3 of 6 of Xcel Electric's AAA report.
[16] Source: Part H, Sections 1-10, page 4 of 6 of Xcel Electric's AAA report.

F. 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.[17] 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 scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 06-1208 Order at 5.

Only Xcel Electric and OTP provided 2019 actuals at the time of filing. MP stated that 2019 actuals would be available after FERC form 1 is filed, in April 2020. MP instead provided the projected maintenance expense for 2019. The Department summarizes the maintenance spending of Xcel, OTP, and MP below. As stated in the Department's FYE18 analysis, Xcel and MP are all spending less on maintenance of their generation facilities than was budgeted in their most recent rate cases, and their spending continues to fall. OTP has increased maintenance spending and actually exceeded the test year amount during the last two years. The Department also notes that, as shown in Department Attachment B2 to the AAA Report, outage costs have decreased as a share of net energy costs since FYE07 and FYE08.

Table 3
Comparison of Generation Maintenance Expense[18]
($ Millions)

	Test Year	Rate Case Budgeted	Actual 2018-2019 Average	Difference
Xcel	2016	184.7	167.3	-9.4%
OTP	2016	15.1	15.5	2.5%
MP*	2020	36.1	36.1	-0.1%

*MP's average is limited to its 2018 actuals.

[17] Department Attachment B2 shows that outage costs have decreased as a share of energy costs since FYE07.
[18] Source: Department Attachment B3.

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 2017 decision[19] 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.

Xcel's maintenance spending declined approximately 7 percent from its 2018 levels, which was already below Xcel's test year budgeted maintenance expense. Xcel has only met or exceeded its budgeted maintenance expense during its 2016 test year and has since underspent substantially. In fact, Xcel underspent by an average of 9.4 percent in 2018 and 2019; in other words, Xcel charged its ratepayers much more in 2018 and 2019 for maintenance costs than the utility actually spent on such efforts.

OTP increased its maintenance expense and exceeded its test year budgeted maintenance expense for the second year in a row. OTP's 2019 maintenance expense was its highest since 2014.

As MP did not provide actuals for 2019, the Department requests that MP provide the actual versus budgeted data for generation maintenance expense for 2019 in reply comments.

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

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

> All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages. The Commission asks the OES [Department] to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.

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

In its FYE07 AAA report, the Department requested suggestions from the utilities regarding improving outage-related contracts to better protect ratepayers. In response, the utilities appeared to jointly state that "while we attempt to include contract terms or performance bonds to indemnify us for

[19] 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.

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 to identify ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities.

While MP stated that "[d]uring this period, there were no delays or lack of performance by contractors, identified which impacted the length of the outages and/or the replacement energy costs"[20] OTP[21] and Xcel[22] shared a useful summary of their processes and procedures to address poor contractor performance.

H. 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 FYE11 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 their July 1, 2018-December 31, 2019 AAA filings, 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.

I. IN THE MATTER OF OTTER TAIL POWER COMPANY'S PETITION FOR APPROVAL OF A MONTHLY FUEL CLAUSE ADJUSTMENT TRUE-UP PROVISION: FCA TRUE-UP REPORT IN DOCKET NO. E017/M-03-30

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

On January 30, 2020, Otter Tail submitted a compliance report and proposal to implement a true-up credit (decrease in rates) of $0.0005 per kWh. In comments filed on February 27, 2020, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit beginning March 1, 2020.

[20] Source: Attachment 18 of MP's AAA report.
[21] Source: Part H, Section 5 of OTP's AAA report.
[22] Source: Part K, Section 3 of Xcel Electric's AAA report.

J. 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."[23] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order in Docket No. E002/M-10-161 regarding WM Renewable Energy.

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

The Commission's March 11, 2011 Order in Docket No. E015/M-10-961 required MP to provide in its annual AAA report information regarding the number of times certain energy products were offered by Manitoba Hydro to MP, the number of times such offers were accepted, and various energy price comparisons.

MP provided the required reporting information in compliance with the Commission's Order in Docket No. E015/M-10-961 regarding Manitoba Hydro PPA.[24]

L. 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,[25] the Commission approved Xcel Electric's proposal to recover Community Solar Garden (CSG) 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 AAA Report, as of December 2019, the Company has been recovering monthly fuel costs from 690 community solar gardens.[26] Xcel's total Community Solar Garden cost recovery in the AAA period was $135,476,279 as shown on Part H, Section 9, Schedule 2, Page 1 of 1.

---

[23] Source: Part H, Sections 1-10, page 4 of 6 of Xcel Electric's AAA report.
[24] Source: Attachment No. 13 of MP's AAA report.
[25] *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.
[26] See Part H, Section 9, Schedule 1, Pages 1 of 7 of Xcel Electric's AAA report for more information on the 690 solar gardens.

The Department reviewed Xcel Electric's Community Solar Garden program costs and was able to tie the solar costs to Xcel Electric's monthly FCA filings. Since Xcel's Minnesota ratepayers pay for Xcel's Community Solar Gardens, 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)[27] at that hour. Market costs are allocated to each jurisdiction based on sales, while costs above market are directly assigned to the Minnesota fuel clause.[28] Based on our review and the determination that Minnesota ratepayers solely bear the costs of Xcel's Community Solar Gardens, the Department concludes that the Community Solar Garden Program costs included in Xcel Electric's FCA appear reasonable.

M. 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:[29]

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.

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:[30]

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, Section 4 and Part K, Section 5 of its AAA Report. In addition, Xcel Electric provided a schedule showing the status of each transformer that exceeds 100 kilovolts in Part H, Schedule 1 of its AAA Report. The Department reviewed Xcel Electric's transformer reporting and concludes that the required information was provided in accordance with the Commission's August 31, 2009 and August 16, 2013 Orders. As a result, the Department

[27] The Locational Marginal Price is the cost of providing the next megawatt of electrical energy at a specific location on the grid.
[28] Part H, Section 9 of Xcel Electric's AAA Report in Docket No. E999/AA-20-171.
[29] See the Commission's August 31, 2009 Order in Docket No. E999/AA-07-1130, Ordering Point No. 16.
[30] See the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792, Ordering Point No. 23.

recommends that the Commission accept Xcel Electric's transformer reporting for the AAA reporting period.

MP provided its transformer reporting in Attachment 12 of its AAA Report. However, the Department notes that MP did not provide their policy for transformer maintenance. The Department requests that MP provide its policy for transformer maintenance in reply comments. The Department will provide its recommendation regarding MP's transformer reporting after reviewing MP's reply comments.

OTP provided its transformer reporting in Part H, Section 8 of its AAA Report. The Department reviewed OTP's transformer reporting and concludes that the required information was provided in accordance with the Commission's August 31, 2009 and August 16, 2013 Orders. As a result, the Department recommends that the Commission accept OTP's transformer reporting for the AAA reporting period.

N. HENNEPIN ENERGY RECOVERY CENTER

The Commission's December 28, 2017 *Order Rejecting Proposed Amendment to Power Purchase Agreement* (December 28 Order) in Docket No. E002/M-17-532 rejected Xcel Electric's proposed amendment to a PPA with the Hennepin Energy Recovery Center (HERC), which was to define pricing terms during a seven-year extension period. Subsequently, Xcel Electric's February 1, 2018 *Response to Reconsideration Request* clarified that "[t]he Second Amendment provides for interim market based pricing for energy sold to the Company after December 31, 2017, at the day-ahead MISO locational marginal price (LMP), adjusted for any applicable MISO market charges and real-time settlement differences."

The Department reviewed the costs Xcel Electric attributed to the HERC power purchase agreement as shown in the Petition's Part H, Section 11, Schedule 1. Based upon this review, the Department concludes that Xcel Electric correctly calculated the interim costs of the HERC PPA. Therefore, the Department concludes that the Xcel Electric complied with the Commission's December 28 Order.

*O. RENEWABLE*CONNECT COSTS*

The Commission's February 27, 2017 *Order Approving Pilot Programs and Requiring Filings* (February 27 Order) in Docket No. E002/M-15-985 approved Xcel Electric's proposals for implementing the Renewable*Connect and Renewable*Connect Government programs (Green Pricing), on a pilot basis. The Commission's approval was contingent upon Xcel Electric adjusting its MISO-accredited wind- and solar-capacity assumptions to reflect MISO's updated values for 2016/2017 planning year.

Regarding the Green Pricing programs and the February 27 Order, the Department reviewed the wind and solar energy mix, the costs of the associated energy mix, the cost exclusion attributable to the neutrality charge, and how the various amounts flowed through the fuel clause adjustment calculations.

The Department did not identify any issues in Xcel Electric's inputs, calculations, or outputs. Therefore, the Department concludes that Xcel Electric correctly calculated the costs of the Green Pricing programs that appear in the fuel clause adjustment.

However, the February 27 Order required Xcel Electric to "provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants." The Department was unable to locate such a discussion. Therefore, the Department recommends that the Xcel Electric in reply comments either indicate where the discussion is located or provide such a discussion.

P. INVER HILLS TANK SALE REFUND

On February 16, 2018, the Commission issued its *Order Approving Petition with Conditions, Approving Cost Recovery Proposal, and Granting Variances* (February 16 Order) in Docket No. E002/PA-17-529 approving Xcel Electric's request to keep a portion of the gain on the sale of land and oil tanks to Flint Hills Resources Pine Bend (Flint Hills). The Order also required Xcel Electric to update 1) its fuel oil loss calculation for fuel prices at the closing of the transaction and 2) file a letter within 10 days of closing on the transaction illustrating Xcel Electric's final calculations.

The Commission's June 18, 2018 *Order Approving Compliance Filing With Modification* (June 18 Order) in Docket No. E002/PA-17-529 approved Xcel Electric's compliance filing, but substituted Commission staff's transaction gain calculation of $0.941 million in place of Xcel Electric's proposed gain calculation; the $0.253 million difference was to be added to the customer's gain portion in the Flint Hills transaction.

The Commission's February 16, 2018 *Order Approving Petition with Conditions, Approving Cost Recovery Proposal, and Granting Variance* in Docket No. E002/PA-17-529 required Xcel Electric to use a placeholder return on equity (ROE) for the Inver Hill asset sale refund until the 2017 Transmission Cost Recovery (TCR) Rider ROE had been decided in Docket No. E002/M-17-797. As required, Xcel Electric filed a journal entries compliance filing on March 12, 2018 with a placeholder ROE of 9.2 percent. This resulted in a sale proceeds credit of $1,929,053, which customers received in the Xcel Electric's April 2018 monthly fuel clause adjustment.

Subsequently, per the Commission's June 18, 2018 *Order Approving Compliance Filing with Modification* (June 18 Order) in Docket No. E00/PA-17-529, Xcel Electric was required to credit customers an additional $253,000 to provide customers with the portion of the gain for the federal and state income tax gross-up. Customers received this credit in the Xcel Electric's August 2018 monthly fuel clause adjustment.

On September 27, 2019, Commission issued its *Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements* (September 27 Order) in the 2017 TCR docket, which specified a 9.06 percent ROE. Xcel Electric's October 31, 2019 compliance filing in Docket No. E002/PA-17-529 provided final journal entries using the 9.06 percent ROE. The total amount due to customers using the 9.06 percent ROE was $2,359,060. Prior to the final compliance filing, Xcel Electric already credited customers $2,182,053 ($1,929,053+$253,000), which resulted in $177,007 still due to customers. That remaining amount was credited to customers in Xcel Electric's November 2019 monthly fuel clause adjustment.

The Department reviewed Xcel Electric's information and concludes that the total credit for the Flint Hills transaction complies with the Commission's February 16 Order, June 18 Order, and September 27 Order.

Q. SHERCO LAND SALE REFUND

On February 6, 2018 in Docket No. E002/PA-17-528, the Commission issued an order (February 6 Order) approving Xcel Electric's proposed options for the potential sales of 50 acres of land at the Sherburne County Generating Station (Sherco) to Northern Metals LLC and 315.2 acres of Sherco land to Jet Stream LLC. The February 6 Order also approved Xcel Electric's proposal to refund the transactions' net gains through the FCA.

Xcel Electric's August 2018 monthly FCA filing in Docket No. E002/AA-18-525 included a credit of $1,275,903 to comply with the Commission's February 6 Order in Docket No. E002/PA-17-528. This amount was slightly above the net gain of $1,222,631 for the Northern Metals LLC transaction estimated by Xcel Electric in its petition in Docket No. E002/PA-17-528.

Xcel Electric's April 2019 monthly FCA filing in Docket No. E002/AA-19-253 at Attachment 1, page 5 included a Sherco Land Sale charge of $54,350. This charge stems from Xcel Electric's over-estimation of the August 2018 net gain and associated refund. Xcel Electric explained that in February 2019 Xcel Electric discovered certain sales charges that were not included in the original calculation. As such there was an over refund in August 2018 FCA. Xcel corrected this difference in April 2019 filing.

The Department reviewed Xcel Electric's information and concludes that the $54,350 update complies with the Commission's February 6 Order.

R. BENSON, PINE BEND AND LAURENTIAN PPAs

1. *Benson PPA*

On January 23, 2018 the Commission issued its *Order Approving Petitions, Approving Cost Recovery Proposals, and Granting Variances* (January 23 Order) in Docket Nos. E002/M-17-530 and E002/M-17-551 approving Xcel Electric's request to terminate a PPA with Benson Power, LLC, acquire the Benson Power, LLC's biomass plant, subsequently close the facility, and recover the associated costs through the FCA. The January 23 Order specifically approved Xcel's proposed FCA variance request to recover investments, expenses and costs, and earnings associated with the Benson Power PPA transaction through the FCA.

The Department reviewed Xcel Electric's calculations used to produce the Minnesota jurisdiction's Benson Power PPA termination and plant purchase. In response to Department Information Request No. 5 Xcel Electric stated:

> In preparing the data response, the Company noted that there was a small cumulative difference ($4,468) between the calculation and the amounts included in the Actual Cost of Fuel for the Benson Amortization and ROE. The difference results from normal monthly updates to the Benson expenditures and the resulting impact to rate base and the return calculation. The Company will reduce the March 2020 Actual Cost of Fuel to recognize the $4,468 over collection.
>
> Additionally, in preparing the response the Company noted differences between the Actual Cost of Fuel amounts and the supporting general ledger detail for the O&M Pass Through amounts for October 2018 and November 2018. In those months, certain transactions in the general ledger were either inadvertently not included or inadvertently not excluded from the Actual Cost of Fuel calculation. These errors resulted in a $7,258 under collection from customers in October 2018 and a $57,606 over collection from customers in November 2018. The Company will reduce the March 2020 Actual Cost of Fuel to recognize the $57,606 over collection for November 2018. The Company does not plan to make an adjustment to collect the $7,258 under collection from customers for October 2018.

Based upon this review the Department concludes that, with the corrections noted by Xcel Electric, the total amount for the Minnesota jurisdiction for the Benson Power transaction in the reporting period complies with the Commission's January 23 Order.

2. Pine Bend PPA

On November 8, 2017 the Commission issued an order (November 8 Order) in Docket No. E002/M-17-531 approving Xcel Electric's request to terminate a PPA with Gas Recovery System Energy, LLC (GRS) and recover through the FCA the expenses and costs associated with the transaction. The November 8 Order specifically approved Xcel Electric's proposed FCA variance request to recover through the FCA monthly payments made by Xcel Electric to GRS until GRS has received a total of $1,050,000 or until the end of three years after monthly payments have begun, whichever is earlier. The monthly payment is equal to the difference between the baseline agreement price and the monthly average of the hourly day-ahead MISO LMP priced at MISO Node NSP.NSP plus $10/ MWh for a presumed energy quantity of 3,000 MWh.

The Department reviewed Xcel Electric's calculations used to produce the Minnesota jurisdiction's Pine Bend PPA termination cost recovery allocation as shown in Part E, Section 5, Schedule 1, line [1b 30] of the Petition. Based upon this review the Department concludes that the total amount of $650,246 for the Minnesota jurisdiction for the GRS transaction complies with the Commission's November 8 Order.

3. *Laurentian PPA*

The January 23 Order approved Xcel Electric's request to terminate a PPA with Laurentian Energy Authority I, LLC (LEA) and recover the associated costs through the FCA. The January 23 Order specifically approved Xcel's proposed FCA variance request to recover through the FCA Xcel Electric's payments to LEA totaling $108.5 million, being paid in equal installments of just over $18 million over six years.

The Department reviewed Xcel Electric's calculations used to produce the Minnesota jurisdiction's LEA PPA termination cost recovery allocation as shown in Part E, Section 5, Schedule 1, line [1b 29] of the Petition. Based upon this review the Department concludes that the total amount of $26,393,071 for the Minnesota jurisdiction for the LEA transaction in the reporting period complies with the Commission's January 23 Order.

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 (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 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. OTP has an annual true-up to refund or recover previous over- and under-recoveries of their energy costs. In MP's base cost of fuel filing (Docket No. E015/MR-19-443) filed concurrently with MP's rate case proposed to recover fuel costs in a method similar to Xcel's method; the Commission approved MP's proposal in its December 23, 2019 Order Accepting Filing and Suspending Rates. Final determination of the method of MP's fuel cost recovery may depend on the outcome of MP's rate case in Docket No. E015/GR-19-442.

B. MINNESOTA POWER

Minnesota Power serves about 122,000 electric customers in northeastern Minnesota. MP's Minnesota Jurisdictional fuel costs were $201,477,350 for FYE19.[31] MP over-recovered its fuel costs by about $1.06 million in FYE19, or approximately 0.53 percent of its actual costs. Compared to FYE18 fuel costs of $21.75/MWh, MP's costs in FYE19 of $23.98/MWh were 10.2 percent higher.[32]

The Department notes that MP's level of under-/over-recovery varies from month to month. In FYE19, MP's monthly under-/over-recoveries ranged from a $6.7 million under-recovery (July 2019), to a $5.1 million over-recovery (October 2019). For reference, the Department notes that, for calendar year 2019, MP had a cumulative over-recovery of approximately $3.99 million.

C. OTTER TAIL POWER COMPANY

Otter Tail serves more than 61,000 Minnesota electric customers, primarily in western Minnesota. During the July 2018-December 2019 reporting period, Otter Tail experienced a 1.6 percent over recovery as a whole, about $1.4 million. As a result, Otter Tail submitted a compliance report on January 30, 2020 with a proposal to implement a true-up credit (decrease in rates) of $0.0005 per kWh.[33] In comments filed on February 27, 2020, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit beginning March 1, 2020.

D. XCEL ELECTRIC

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-recovery of costs that it experienced two months prior to the month in which it applies a new FCA.

Xcel Electric serves about 1.2 million electric customers in Minnesota, primarily in the metro area. At the end of 2019, Xcel Electric experienced a cumulative over recovery of about $13.6 million. As a result, Xcel Electric submitted a compliance report on January 31, 2020 with a proposal to implement this true-up credit in equal parts ($6,805,274) over the March and April 2020 fuel cost charges.[34] In comments filed on March 2, 2020, the Department recommended that the Commission approve Xcel Electric's proposed March and April 2020 fuel cost charges with true-up, subject to any input adjustment to Xcel's calculations following the Commission's Order in Docket No. E999/AA-20-171.

[31] See Department Attachment B4.
[32] See Department Attachment B5.
[33] Docket No. E017/M-03-30.
[34] Docket No. E002/AA-20-182.

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.

In the past, these three Minnesota electric investor-owned utility companies were required to provide the information below as part of their AAA reports. The Department summarizes the companies' responses to the seven ordering paragraphs as discussed below.

On June 12, 2019, the Commission in Docket No. E999/AA-03-802 approved excluding the MISO Schedule 10 review in the AAA reports.[35] Since this reporting requirement ended during this reporting period, the Department has largely excluded the MISO Schedule 10 review from our MISO Day 1 review below.

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.

The only remaining deferred costs for this reporting period regards MISO's 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. These deferred integration costs will be recovered over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company. On January 1, 2019, amortization of those costs ended.

In their AAA reports, the utilities noted that there are no new MISO cost deferrals.

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 AAA reporting period.

C. EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF DELIVERY OF A FIRM PURCHASED 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 AAA reporting period.

---

[35] See the Commission's June 12, 2019 Order in Docket No. E999/AA-03-802.

D. CHANGES TO MISO TARIFFS THAT MAY ULTIMATELY AFFECT THE RATES OF RETAIL CUSTOMERS IN 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, 2018 to December 31, 2019, MISO submitted a significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect rates of retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available by month at the MISO web site (www.midwestiso.org) at the "FERC Filings and Orders" tab available under the "Library" tab on the MISO home page.

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

- MISO has included Schedules 16 and 17 in its Open Access Transmission, Energy and Operating Reserve 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 note that an overall net increase in transmission costs has occurred due to an increase in costs charged under Schedule 10, which pertains to MISO's administrative charges, offset by a decrease in costs due to elimination of transmission rate "pancaking" and elimination of the Mid-Continent Area Power Pool (MAPP) or Mid-America Interconnected Network (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 current AAA report and past AAA reports, Xcel Electric provided the following response[36] 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 available to MISO both its Company-owned and purchased resources for 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 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, our 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 MISO's provision of 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

As noted above, the Commission discontinued the requirement that utilities report on MISO Day 1 data. The Department still 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.

---

[36] Xcel Electric's AAA Report in Docket No. E999/AA-20-171 in Part I, Sections 1-7 pp. 7-8.

VI. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

This AAA Report is based on thirteen 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[37] 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[38]), 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 Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). 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 of their generation resources (either owned generation or purchases) that are "Network Resources" of the market participant. At the same time, each MISO load-serving entity (LSE) participant must bid their load requirements into the market. (Since utilities are market participants with generation and are also LSEs, utilities participate with both bids and offers.) After receiving the generation offers and load bids, MISO determines the optimal supply of resources that reflects delivery constraints on the transmission grid. MISO "clears" both the day-ahead and real-time markets over its entire footprint, based on participants' bids and offers and the limitations of the transmission system, with the optimized cost of supply.

---

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

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 FCA on an interim basis subject to refund.[39]

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.[40]

In addition, the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions tend to cancel each other, the utility's records reflect the net, or actual, cost or revenue from the operations. Finally, the Commission proposed an investigation into the best method for assuring low-cost electricity in Minnesota.[41] These basic principles are still in place.

Third, on reconsideration, the 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 adjustment. While this recovery remained as interim, subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring the MISO Day 2 administrative costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[42]

---

[39] *Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest* (April 7, 2005) in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406.

[40] *Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation* (December 21, 2005 Order) in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406.

[41] December 21, 2005 Order in Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406 at Ordering Paragraph 10.

[42] *Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings* at 7-8.

On June 22, 2006, the parties filed the *Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery* (Joint Report) with the Commission.[43] 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 clause adjustments. 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 an unexpected mechanical failure at a power plant.

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

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the

[43] 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.

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 *Order Establishing Accounting Treatment for MISO Day 2 Costs*, Ordering Paragraph 7, part g. This MISO Day 2 spreadsheet of charges and additional support for MISO Day 2 net cost allocations, especially between retail and wholesale, was updated in the Commission's February 6, 2008 Order for the 2006 AAA, in Ordering Paragraphs 21 to 24.

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

Xcel Electric allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale/intersystem, and non-asset-based wholesale/intersystem. The Company's invoices from MISO 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 19 of 19 of Xcel's Electric's AAA Report for the 18-month period from July 2018 to December 2019. 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 4.1: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE11	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18	FYE19[44]	FYE20[45]
Net Costs	$195.9[46]	$196.6[47]	$200.5[48]	$222.9[49]	$101.7[50]	$54.6[51]	$87.9[52]	$63.1[53]	$84.0[54]	$28.2[55]

The Department notes that the total or net[56] MISO Day 2 costs assigned to Xcel Electric's retail ratepayers increased from the FYE18 reporting period but remain quite low compared to previous periods (FYE11 – FYE15).

The Department reviewed Xcel Electric's MISO Day 2 charges for FYE19 (July 2018 through June 2019) and FYE20 (July 2019 through December 2019). The Department performed a limited review of some charge types that appeared to show significant changes between FYE18 and FYE19/FYE20. In addition, the Department reviewed Xcel Electric's allocation of MISO Day 2 costs.

The Department notes that Xcel Electric's total net MISO Day 2 costs/(revenues) totaled ($176,156,831) for retail and asset-based wholesale/intersystem for the 18-month period ending December 31, 2019.[57] Of this amount, $112,210,193 in net costs were assigned to retail and ($288,367,024) in net revenues were assigned to asset-based wholesale/intersystem.[58]

The Department notes that Xcel Electric's total net MISO Day 2 costs/(revenues) increased significantly from $6,584,399 in September 2018 to $10,058,540 in October 2018 to $6,555,026 in November 2018. The Department recommends that Xcel Electric explain the significant increase in October 2018 total net MISO Day costs in reply comments.

---

44 For comparison purposes with previous AAA filings, the Department used the figures for the 12-months ending June 30, 2019 (FYE19).

45 Represents the six-month period from July 1, 2019 through December 31, 2019 (FYE20).

46 Source: Xcel Electric's initial filing in Docket No. E999/AA-11-792, Part J, Section 5, Schedule 7, Page 13 of 13.

47 Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.

48 Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.

49 Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 7, Page 13 of 13.

50 Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 7, Page 13 of 13.

51 Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 7, Page 13 of 13.

52 Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 7, Page 13 of 13.

53 Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 7, Page 13 of 13.

54 Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 7, Sum of Pages 1-12.

55 Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 7, Sum of Pages 13-18.

56 As discussed in section VI A above, the Commission directed the 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.

57 Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 7, Page 19 of 19.

58 *Id.*

The Department also 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*.[59] The Department asked Xcel Electric via email if they had changed any of the allocation methods used to allocate MISO Day 2 charges between retail and asset-based wholesale from FYE18 to the current AAA reporting period (July 2018 to December 2019). Xcel Electric confirmed via email that there have been no changes to the allocation methods for MISO Day 2 charges between retail and asset-based wholesale from FYE18 to the current AAA reporting period. Thus, the explanation referenced above, which the Department incorporates by reference, remains valid.

The Department will provide its recommendation regarding Xcel Electric's MISO Day 2 reporting and allocations for the current AAA reporting period after it has reviewed Xcel Electric's reply comments.

2. Review of MP's MISO Day 2 Charges

Attachment 8 to Minnesota Power's AAA Report contains 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 FYE19 and FYE20 increased significantly compared to prior years, as shown in the below table.

Table 4.2: 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%
FYE18	55.7	24.9%	47.4	5.8%
FYE19	90.0	61.4%	71.6	51.1%
FYE20[60]	44.7	-0.4%	34.4	-3.9%

Source: Attachment 9 (FYE11-FYE18) and Attachment 8 (FYE19-FYE20) MP AAA Report

[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.

[60] FYE20 represents the 6 month period July 1, 2019 to December 31, 2019.

The Department notes that MP's AAA Report on page 114 of Attachment 8, shows that Total MISO Day 2 and ASM net charges for the (July 1, 2018 to December 31, 2019 or 18 month period) was $134.7 million[61] of which $106.0 million[62] was assigned to retail customers. The Department used MP's AAA Report information on page 114 of Attachment 8 to determine the $134.7 million in MISO Day 2 and ASM net charges was assigned $134.6 million to MISO Day 2 charges and $0.1 million to ASM charges for Total MISO Charges.

As part of our review, the Department noted that a significant portion of the $134.7 million Total MISO Day 2 and ASM net charges (for the July 1, 2018 to December 31, 2019 or 18 month period) was for Day-Ahead and Real-Time Energy of $108.0 million related to 14.9 million megawatt hours as shown on page 112 of Attachment 8 of MP's AAA Report. The Department noted that a significant portion of the $55.7 million in Total MISO Day 2 and ASM net charges (for July 1, 2017 to June 30, 2018 or 12 month period) was for Day-Ahead and Real-Time Energy of $35.5 million related to 10.5 million megawatt hours as shown on page 75 of Attachment 9 of MP's 2018 AAA Report.

As a result of the significant increase in MISO Day 2 charges for FYE19 and FYE20 compared to FYE18, as shown in Table 4.2 above, the Department requests that MP explain in its reply comments the main drivers that caused these increases. Additionally, the Department requests that MP in its reply comments provide the MISO bills that support the $13.6 million in MISO Day 2 and ASM net charges for the month February 2019. The Department also requests that MP in its reply comments support its cost allocation of $10.9 million to retail customers "FPE Retail" for February 2019 (as shown on MP's Attachment 8, page 48) and provide any plant outages information for February 2019.

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*.[63] Because those allocation methods have not changed, the Department will describe them only briefly in this report.[64]

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

---

[61] Table 4.2 shows FYE19 of $90.0 million plus FYE20 of $44.7 million.

[62] Table 4.2 shows FYE19 of $71.6 million plus FYE20 of $34.4 million.

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

[64] MP via email confirmed that there have been no allocation changes for MISO Day 2 and ASM charges.

The Department requests the above information from MP in reply comments, before the Department can conclude that MP's MISO Day 2 charges as reported in Attachment 8 to MP's AAA Report for the period July 2018 to December 2019 are reasonable.

3. *Review of OTP's MISO Day 2 Charges*

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part H Section 3 Attachment K of OTP's 2018-2019 AAA Report. The Department notes that amounts reflected in Attachment K are at the total-Company level and not the Minnesota jurisdictional level.

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

Table 4.3: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	July-December 2019
Revenues	$102.6	$70.8	$94.1	$115.3	$109.9	$43.1
Costs	$142.7	$111.5	$132.4	$151.8	$159.5	$61.3
Net Costs	$40.1	$40.1	$38.3	$36.5	$49.6	$18.3

The Department has included all of the information request responses for MISO Day 2, Asset Based Margins and Ancillary Services Market (ASM) as Department Attachment A for OTP. The Department reviewed OTP's MISO Day 2 charges as reported in Part H Section 3 Attachment K to OTP's 2018-2019 AAA Report.

In Department Information Request No. 8, 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:

> MISO defines the Day-Ahead Non-Asset Energy Amount as the net charges and credits expressed in dollars 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. Otter Tail is the supplemental energy supplier for certain tribal, agency, and municipal loads within our service territory. The base energy for these loads is provided by the Western Area Power Administration (WAUE). WAUE is an SPP member, not a MISO member. For WAUE to serve these tribal, agency, and municipal loads within MISO, they must inject energy at the MISO/SPP interface node. MISO credits Otter Tail for the WAUE injection at the MISO/SPP interface (hence a non-asset energy source), and then charges

> Otter Tail when the load is withdrawn at the tribal, agency, and municipal loads. The WAUE energy schedules vary by month and by hour. Furthermore, the locational marginal price (LMP), which determines how much Otter Tail is credited for the WAUE energy injection, varies by hour based on market conditions. These ever-changing injection schedules and the attributable LMP pricing result in fluctuating amounts from reporting period to reporting period.
>
> Real-Time Congestion fluctuation is the result of changing market conditions, generation levels, and loading levels. Congestion is one component of LMP pricing (along with energy and losses). Each pricing node has an LMP price with an associated congestion component. Real-Time Congestion is simply measuring, and quantifying, the difference between the Otter Tail load zone congestion and the Otter Tail generation congestion. Changing LMP market pricing is often driven by a change in the congestion component of the price. Any number of factors can cause congestion changes between our generation and load, including, but not limited to, changing weather patterns, transmission constraints or outages, loss of generation, increased loading, etc. It should also be noted that the real-time market is always truing up to deviations (dollars and MWs) that have already been settled in the day-ahead market. The combination of these factors results in a Real-Time Congestion charge that fluctuates significantly (including positive to negative) from one reporting period to another reporting period.

The Department also reviewed OTP's allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[65] In Department Information Request No. 7, the Department requested that OTP explain if any of the Company's allocation methods have changed from the 2010-2011 method for the FYE19 reporting period and if so what the nature of these changes were and the effect these changes have had on the charges assigned to various customer categories. OTP responded that there were no changes to the allocation methods used for FYE19.

The Department recommends that the Commission accept OTP's MISO Day 2 reporting as the Company has provided the required information.

D. ASSET-BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

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

[65] 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 4.4: Xcel Electric
Minnesota Net Asset-Based Margins (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18	FYE19	FYE20
Asset-Based Margins	($4.8)[66]	($7.9)[67]	($7.2)[68]	($4.0)[69]	($4.0)[70]	($18.3)[71]	($21.5)[72]	($XX.X)[73]	($XX.X)[74]

In past AAA filings, the Department asked Xcel Electric to provide its Minnesota net asset-based margins for the reporting period in an information request. Similarly, the Department recommends that Xcel Electric provide its Minnesota net asset-based margins for the July 2018 to June 2019 (FYE19) reporting period and the July 2019 to December 2019 (FYE20) reporting periods in reply comments.

In past AAA filings, the Department also selected a monthly MISO Day 2 asset-based sales amount and traced the Minnesota Net Portion, which was provided by Xcel Electric in an information request response, back to the monthly FCA in which it was returned to ratepayers. For purposes of this proceeding, the Department selects the month of February 2019 and the asset-based sales amount of ($15.3 million)[75] for testing. The Department recommends that Xcel Electric provide the asset-based margin calculation showing the February 2019 Minnesota Net Portion and identify the monthly FCA in which it was passed back to Minnesota ratepayers in reply comments. The Department will provide its recommendations regarding asset-based margins after reviewing Xcel Electric's reply comments.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2019, and compares actual margins to the revenue credit built into MP's base rates each year. The Department does a detailed review of asset-based margins in MP's rate cases. As shown in the table below, the sum of MP's actual margins over the eleven-year period ($419.9 million) is greater than its total credits provided in rates to customers of ($401.6 million) over the same period by 4.6 percent. Based on our review, the Department concludes that MP's asset-based margins appears to be reasonable.

---

66 Per Xcel Electric's Response to Department Information Request No. 35, Attachments A-B in Docket No. E999/AA-16-523; includes monthly true-up amounts.
67 *Id.*
68 *Id.*
69 *Id.*
70 *Id.*
71 Per Xcel Electric's Response to Department Information Request No. 24, Attachment A in Docket No. E999/AA-17-492; includes monthly true-up amounts.
72 Per Xcel Electric's Response to Department Information Request No. 13, Attachment A in Docket No. E999/AA-18-373; includes monthly true-up amounts.
73 To be provided by Xcel Electric in reply comments.
74 *Id.*
75 Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 7, Page 8.

Table 4.5: Minnesota Power Wholesale Asset-Based Margins 2009-2019[76] [77]

Minnesota Power
Wholesale Asset-Based Margins
2009-2019

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Loss)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
2014	$34.7	$37.7	($3.0)	-8.1%
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%
2018	$39.7	$35.8	$3.9	10.9%
2019	$42.3	$35.8	$6.5	18.2%
11 Yr. Total	$419.9	$401.6	$18.3	4.6%

3. *OTP*

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

[76] Source for Revenue Credit in Base Rates: 2009 per May 4, 2009 Order in Docket No. E015/GR-08-415; 2010-2016 per November 2, 2010 Order in Docket E015/GR-09-1151; 2017-2018 per J. Pierce Supp. Direct p. 10 & Sch. 5 p. 17 in Docket E015/GR-16-664.

[77] Actual Margin: Department August 25, 2016 *Review of the 2014-2015 Annual Automatic Adjustment Reports* Part II, page 15; 2016 Actual per MP Response to Department Information Request No. 9 in Docket No. E999/AA-16-523; 2017 Actual per MP's response to Department Information Request No. 13 in Docket No.E999/AA-17-492; 2018 Actual per MP's response to Department Information Request No. 18 in Docket No. E999/AA-18-373.

Table 4.6: Otter Tail Power's Minnesota Asset-Based Margins

AAA Reporting Period	FYE15	FYE16	FYE17	FYE18	FYE 19[78]	July-December 2019
Asset-Based Margins	$1,545,701	$11,812	$826,096	$915,598	$1,151,574	$222,852

The Department notes that OTP's asset-based margins have fluctuated significantly from year-to-year as shown in the above table. The fluctuations of asset-based margins appear 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 the reporting period to ensure asset-based margins were returned to ratepayers via the FCA.

Based on our review of OTP's response to Department Information Request No. 9, including Attachments 1, 2, and 3 the Department concludes that OTP has returned its asset-based margins through the monthly FCAs for the reporting period. Based on our review, the Department concludes that OTP's asset-based margins appear to be reasonable.

E. DEPARTMENT 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 state 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 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.

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.

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

[78] Source: OTP's FYE19 AAA filing, Part H, Section 3, Attachment K, page 38 of 42. Figures for the previous years were provided in the same section of the relevant previous filings, although page numbers may differ.

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, and the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions. The Department has asked Xcel and MP for additional information related to MISO Day 2 in reply comments; therefore, the Department will wait until reviewing this additional information before providing final recommendations to the Commission regarding Xcel's and MP's AAA Reports for MISO Day 2.

The Department recommends that the Commission accept OTP's MISO Day 2 reporting for the AAA reporting period.

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 Deployment 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. E001, 015, 002, 017/M-08-528 (Commission's August 23, 2010 ASM Order) approved Xcel Electric's, MP's, and Interstate Power and Light Company's ASM accounting and recovery via the FCA and required reporting requirements as follows (the Department notes that OTP's ASM was approved via OTP's rate case in Docket No. E017/GR-10-239):

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

2. The Commission finds that the record demonstrates overall benefits from the three utilities' participation in the MISO ancillary services market and that the record supports the continued use of the Fuel Clause Adjustment to pass through the costs and revenues associated with that participation. The three utilities are authorized to continue using the Fuel Clause Adjustment to pass through the costs and revenues associated with their participation in the MISO ancillary services market.

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

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

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

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

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

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

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

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

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

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

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

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

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in Part J, Section 5, Schedules 8 to 13 and in Part J, Section 6 of its AAA Report as required by the Commission's August 23, 2010 ASM Order.

The Department notes that Xcel Electric's total net ASM charges/(revenues) assigned to retail totaled \$16,517,320[79] for the period from July 2018 through June 2019 (FYE19) and \$11,326,340[80] for the period from July 2019 through December 2019 (FYE20).

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:

---

[79] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 13, Sum of Pages 1-12.

[80] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 13, Sum of Pages 13-18.

Table 5: Xcel Electric
Total MISO ASM Charges Assigned to Retail (in millions)

AAA Reporting Period	FYE12	FYE13	FYE14	FYE15	FYE16	FYE17	FYE18	FYE19	FYE20
Net Costs	$13.9[81]	$24.7[82]	$23.5[83]	$24.6[84]	$23.0[85]	$8.3[86]	$24.4[87]	$16.5[88]	$11.3[89]

The Department notes that Xcel Electric's retail ASM costs have decreased significantly from $24.4 million in FYE18 to $16.5 million in FYE19. In addition, the Department notes that FYE20 retail ASM costs of on an annualized basis ($11.3 million x 2 = $22.6 million) are similar to many previous years' costs (FYE18 and FYE13-FYE16). The Department notes that the vast majority of the FYE19 decrease can be attributed to decreases in Real Time Non Excessive Energy Charges.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE19 and FYE20.[90] Xcel Electric indicated net ASM net savings of $3.1 million[91] for the total NSP system and $2.3 million[92] for the Minnesota jurisdiction in FYE19 and FYE20 combined.

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 does not include any additional benefits that have accrued to ratepayers for the reduction in regional regulation 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.

[81] Source: Xcel Electric's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[82] Source: Xcel Electric's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[83] Source: Xcel Electric's initial filing in Docket No. E999/AA-14-579, Part J, Section 5, Schedule 13, Page 13 of 13.
[84] Source: Xcel Electric's initial filing in Docket No. E999/AA-15-611, Part J, Section 5, Schedule 13, Page 13 of 13.
[85] Source: Xcel Electric's initial filing in Docket No. E999/AA-16-523, Part J, Section 5, Schedule 13, Page 13 of 13.
[86] Source: Xcel Electric's initial filing in Docket No. E999/AA-17-492, Part J, Section 5, Schedule 13, Page 13 of 13.
[87] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Page 13 of 13.
[88] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 13, Sum of Pages 1-12.
[89] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171, Part J, Section 5, Schedule 13, Sum of Pages 13-18.
[90] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171 Part J, Section 6, Page 3 of 6.
[91] Source: Xcel Electric's initial filing in Docket No. E999/AA-20-171 Part J, Section 6, Page 3 of 6.
[92] Calculated; $3.1 million x 75% = $2.3 million.

The Department notes that Xcel Electric's total system EDEDC decreased from $1.0 million[93] in FYE18 to $840,468[94] in FYE19 and $262,127[95] in FYE20.

Xcel Electric stated the following in its AAA Report regarding EDEDC:

> A certain level of EDEDCs is unavoidable given the current design of the ASM market. Currently for each generator, the Company can only submit a single ramp rate value that represents the average rate at which the generator can increase or decrease output across its entire dispatchable range. For a typical coal unit, the ramp rate varies significantly as the unit moves from minimum load to full load. For example, a coal generator with a minimum capability of 200 MWs and a maximum capability of 400 MWs might be able to operate to 300 MWs with one coal pulverizer in operation, while a generator with a capability between 300 MWs and 400 MWs would require two coal pulverizers to be in operation. The unit might be able to ramp at a rate of 10 MWs/min up to 300 MWs, then slow to 3 MWs/min while the second pulverizer is starting, and then ramp at 5 MWs/min up to 400 MWs. The Company could offer only 3 MWs/min of ramp capability to MISO for dispatch, which would ensure that the unit would be able to follow its dispatch instruction close to 100% of the time, but would drastically under-represent the capability of the unit over most of its dispatchable range.
>
> Offers with low ramp rates mean that the unit will not be able to clear for as much regulation reserve or spinning reserve, and therefore will not be available to fully hedge the Company's cost to procure these services. Low ramp rates also limit the unit's ability to respond to increasing or decreasing LMP prices, which ultimately leads to higher purchase power costs in the market. A more prudent strategy would be to offer 5 or 6 MWs/min of ramp capability for the entire range to strike an appropriate balance between incurring penalties during the limited intervals that the unit would not be able to "keep up," and ensuring the unit can provide sufficient quantities of ancillary and load following services to hedge exposure to market prices.
>
> The ASM benefit calculation is a measure of the extent to which the Company has struck the appropriate balance between too much or too little flexibility being offered to MISO. For the 2018-2019 AAA reporting period, the net benefit for the Company was approximately $2.0 million while the amount incurred in EDEDCs was $1.1 million. The $3.5 million in gross benefits would not have been achievable if the Company had been

---

[93] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 6, Page 5 of 7.

[94] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Pages 1-12.

[95] Source: Xcel Electric's initial filing in Docket No. E999/AA-18-373, Part J, Section 5, Schedule 13, Pages 13-18.

> offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy charge.
>
> 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. [Footnotes omitted]

The Department reviewed Xcel Electric's total system EDEDC charges and notes that they have been decreasing over the last few years and remain minimal. Moreover, the Department agrees with Xcel Electric that some level of EDEDC charges are inevitable. As a result, the Department concludes that Xcel Electric's EDEDC charges for the AAA reporting period appear reasonable.

2) Contingency Reserve Deployment Failure Charges (CRDFC)

Xcel Electric provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for the AAA reporting period (FYE19 and FYE20) 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 increased from $10,176 in FYE18 to $70,994 in the current AAA reporting period.

Xcel Electric provided a long explanation of CRDFC's in Part J, Section 6 of its AAA Report and stated the following in summary:

> 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 our review, the Department concludes that Xcel Electric's CRDFC charges for the AAA reporting period appear reasonable.

3) Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount

As explained in the Department's February 7, 2018 Response Comments in Docket E999/AA-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 (see Order Point 6 of the Commission's March 16, 2018 Order in Docket No. E999/AA-16-523).

Xcel Electric complied with the Commission's March 16, 2018 Order in Docket 16-523 by providing a breakout of the two new charge types as shown in Part J, Section 5, Schedule 8, Page 13 of 13 of its AAA Report. As shown therein, Xcel Electric's Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount totaled ($119,082) and ($50,983), respectively, for the AAA reporting period.

Based on our review, the Department concludes that Xcel Electric's Day Ahead Ramp Capability Amount and Real Time Ramp Capability Amount for the AAA reporting period appear reasonable. The Department will continue to monitor these charge types in future AAA filings.

4) *ASM Summary*

The Department reviewed Xcel Electric's ASM charges and concludes that, although there is some fluctuation in various amounts, Xcel Electric's ASM charges for the AAA reporting period appear to be reasonable. As a result, the Department recommends that the Commission accept Xcel Electric's ASM reporting for the AAA reporting period.

C. MP

1. Overall Review of ASM Costs and Revenues

MP addressed ASM costs and revenues in Attachment 9 to MP's AAA Report for the period July 2018 to December 2019 (18 month period). MP reported net costs of $122,969 for the 18 month period, which was lower than the net costs of $457,229 for FYE18. The Department reviewed MP's Table 9A - Summary of ASM Charge Types, and Table 9B - Summary of ASM Products Purchased and Supplied, found in MP's Attachment 9, and did not note anything unusual.

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. The Department notes that MP allocated $87,293 of net ASM costs to the Retail FCA of the total $122,969 net ASM costs for the period July 2018 to December 2019.

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 Charge (EDEDC) and the Contingency Reserve Deployment Failure Charges for the current period July 2018 to December 2019, since these are basically performance penalties.

The Department notes that MP's real time EDEDC amount increased to $467,373 for the current 18 month period, compared to the $91,031 in FYE18. According to MP the majority of the EDEDC occurs during start-up, shut downs, set point deviations, or when the unit is having equipment problems and is not considered dispatchable by MISO. Additionally, MP incurred only $285 in Contingency Reserve Deployment Failure Charges for the current 18 month period, compared to the $1,167 in FYE18. MP explained that the penalties were due to 3 operating days during which MP was short a total of 10.8 MWh. The Department notes that overall these charges continue to be minimal.

3. *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. 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.

MP's Day Ahead and Real Time Ramp Capability Amounts during May and June of 2016 totaled approximately negative/credit of $1,600. In FYE17 and FYE18, the Day Ahead and Real Time Ramp Capability Amounts totaled a negative/credit of $20,780 and $24,018. For the period July 2018 to December 2019, the Day Ahead and Real Time Ramp Capability Amounts totaled a negative/credit of $5,753 (that is a reduction to MP's total MISO charges).

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 circumstance 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 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 is billed via the Real-Time Revenue

Neutrality Uplift Amount, an existing charge type that is already included in the fuel clause. The Department notes that if the Ramp Capability Products were to be excluded from the fuel clause adjustment, 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 associated revenues.

4. *Schedule 17, MISO Administrative Costs for ASM*

Attachment 9, Table 9-C compared MP's MISO Schedule 17 charges prior to the start of the ASM market to its Schedule 17 charges in the current MP AAA Report. In the current MP AAA Report, the average monthly MISO Schedule 17 charges were $151,533 or $10,610 higher than the average monthly charges prior to the start of the ASM market. This amount equates to an average monthly increase of $0.010366 on a per MWh basis. This comparison attempts to identify the MISO Schedule 17 charges of approximately $151,533 that are related to ASM.

The Department reviewed MP's AAA Report regarding ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept Minnesota Power's ASM reporting for the period July 2018 to December 31, 2019.

D. OTP

In Part H Section 4, Attachment L of its FYE19 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 ASM Order. Specifically, OTP noted that ASM market transition has been smooth from an operational standpoint. OTP noted that there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has led to greater operational efficiency. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, Ramp Capacity and Supplemental Reserve). As a result, ASM provided net benefits of $118,991 to Minnesota ratepayers from July 2018 through June 2019 and net benefits of $103,308 from July through December 2019. OTP allocates all ASM charges on a per-MWh approach, netting costs and benefits of the various charges. The Company stated, in response to Department Information Request No. 7, that there have been no changes to the allocations of the ASM costs (revenues) during the FYE19 reporting period.

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

According to OTP on page 232-233 of OTP's FYE19 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 FYE19 there was a total of ($17,493) of penalties (Page 1, Schedule 1 of Part H, Section 4, Attachment L column R, line 17) and a total of ($7,359) of penalties from July to December of 2019 assessed to Otter Tail units (Page 2, 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 situations would normally be short intervals where some mechanical failure occurred. For the FYE19, there was a total of ($9,425) in charges (Page 1 Schedule 1 of Part H, Section 4, Attachment L, column R, line 16) and there were no charges (Page 2 Schedule 1 of Part H, Section 4, Attachment L, column R, line 16).

The Department notes that OTP's total deployment charges/penalties of $26,918 for the FYE19 and $7,359 for July through December of 2019 were relatively minor.

2. Day-Ahead Ramp Capability Amount and Real-Time Ramp Capability Amount

Beginning in FYE17 OTP began reporting on a new MISO ASM charge for Ramp Capabilities. In Part H, Section 4, Attachment L, page 2 of 4 of their FYE19 AAA Report OTP stated that the MISO Ramp Capability product was designed to increase reliability and decrease the cost of serving load by allowing MISO to be able to better react to changes in power demand. The cost MISO incurs by creating additional ramp capability is offset by the reduced likelihood of insufficient ramp and shortage pricing. OTP received a net benefit of $6,645 for the FYE19 AAA period (Page 1 Schedule 1 of Part H Section 4 Attachment L, column R, line 15) and $3,197 for July through December 2019 (Page 2 Schedule 1 of Part H Section 4 Attachment L, column R, line 15) from these charges.

The Department reviewed OTP's ASM charges and concludes that, although there is some fluctuation in various amounts, OTP's ASM charges appear to be reasonable and are consistent with historical numbers. As a result the Department recommends that the Commission accept OTP's ASM reporting for the reporting period.

VIII. FUEL COSTS AND EFFECTS ON CUSTOMER BILLS

Department Attachment B6 shows various aspects of fuel charges and the effects on customers' bills for informational purposes.

1. Average Residential Bills for 2019

The graph on page 1 of Department Attachment B6 illustrates the monthly average bills for residential customers in calendar year 2019. The information includes customer charges, energy charges, fuel clause adjustments, and Conservation Improvement Program (CIP) surcharges. Overall, Otter Tail Power had the highest average monthly residential bill of $101.05, followed by Minnesota Power at $87.98 and Xcel with the lowest average of $87.21 per month.

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

The graph on page 2 of 4 of Department Attachment B6 shows the amounts that residential customers paid during calendar year 2019 in energy charges plus fuel clause adjustments. The ranking from highest to lowest average monthly amounts paid are: Xcel Electric with an average of 12.01¢/kWh, Minnesota Power with an average of 10.83¢/kWh, and Otter Tail 9.46¢/kWh. However, the Department notes that, because utilities recover different amounts of fixed costs in the energy charges, this comparison is not as useful as the bill comparison in item 1 above.

IX. RECOMMENDATIONS AND REQUESTS FOR ADDITIONAL INFORMATION

A. SECTION II, FILING REQUIREMENTS

The Department recommends that the Commission accept Xcel Electric's, MP's and OTP's Auditor Reports.

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 2019.

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 Report.

The Department was not a party to the FCA Settlement Agreement approved by the Commission in Docket No. E002/GR-05-1428, 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.

The Department requests that MP provide data for generation maintenance expense for 2019 in reply comments.

The Department concludes that the IOUs complied with the reporting requirement of Order Points 8 and 22 of the April 6, 2012 Order in Docket No. E999/AA-10-884.

The Department concludes that Xcel Electric complied with the April 30, 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 March 11, 2011 Order in Docket No. E015/M-10-961 regarding the Manitoba Hydro PPA.

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

The Department recommends that the Commission accept Xcel Electric's transformer reporting for the AAA reporting period.

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 after it has reviewed MP's reply comments.

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

The Department concludes that Xcel Electric has correctly calculated the interim costs of the HERC power purchase agreement.

The Department concludes that Xcel Electric has correctly calculated the costs of the Renewable*Connect Green Pricing programs that appear in the fuel clause adjustment. However, the February 27 Order required Xcel Electric to "provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants." The Department was unable to locate such a discussion. Therefore, the Department recommends that the Xcel Electric in reply comments either indicate where the discussion is located or provide such a discussion.

The Department concludes that the total credit for the Flint Hills transaction complies with the Commission's Orders in Docket No. E002/PA-17-529.

The Department concludes that the total credit for the options for the potential Sherco land sales complies with the Commission's February 6 Order in Docket No. E002/PA-17-528.

The Department concludes that, with the corrections noted by Xcel Electric, the total amount for the Minnesota jurisdiction for the Benson Power transaction in the reporting period complies with the Commission's January 23 Order.

The Department concludes that the total amount of $650,246 for the Minnesota jurisdiction for the GRS transaction complies with the Commission's November 8 Order.

The Department concludes that the total amount of $26,393,071 for the Minnesota jurisdiction for the LEA transaction in the reporting period complies with the Commission's January 23 Order.

C. SECTION IV, FUEL COST REVIEW

In comments filed on February 27, 2020 in Docket No. E017/M-03-30, the Department recommended that the Commission approve Otter Tail's compliance report for the AAA reporting period and the true-up credit beginning March 1, 2020.

In comments filed on March 2, 2020 in Docket No. E002/AA-20-182, the Department recommended that the Commission approve Xcel Electric's proposed March and April 2020 fuel cost charges with true-up, subject to any input adjustment to Xcel's calculations following the Commission's Order in Docket No. E999/AA-20-171.

D. RECOMMENDATIONS FOR MISO DAY 1

The Commission's June 12, 2019 Order in Docket No. E999/AA-03-802 suspended the need to report data on MISO Day 1. The Department still 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.

E. MISO DAY 2 REPORTING AND ALLOCATIONS

- The Department recommends that Xcel Electric explain the significant increase in October 2018 total net MISO Day costs in reply comments. The Department will provide its recommendation regarding Xcel Electric's MISO Day 2 reporting and allocations for the current AAA reporting period after it has reviewed Xcel Electric's reply comments.

- As a result of the significant increase in MISO Day 2 charges for FYE19 and FYE20 compared to FYE18, as shown in Table 4.2 above, the Department requests that MP in its reply comments to explain the main drivers that caused these increases. Additionally, the Department requests that MP in its reply comments provide the MISO bills that support the $13.6 million in MISO Day 2 and ASM net charges for the month February 2019. The Department also requests that MP in its reply comments support its cost allocation of $10.9 million to retail customers "FPE Retail" for February 2019 (as shown on MP's Attachment 8, page 48) and provide any plant outages information for February 2019.

- The Department recommends that the Commission accept OTP's MISO Day 2 reporting and allocations for the reporting period.

F. RECOMMENDATIONS FOR ASSET BASED MARGINS

- The Department recommends that Xcel Electric provide the asset-based margin calculation showing the February 2019 Minnesota Net Portion and identify the monthly FCA in which it was passed back to Minnesota ratepayers in reply comments. The Department will provide its recommendations regarding asset-based margins after reviewing Xcel Electric's reply comments.

- The Department concludes that MP's asset-based margins for the AAA reporting period appear to be reasonable.

- The Department concludes that OTP's asset-based margins for the AAA reporting period appear to be reasonable.

G. RECOMMENDATIONS FOR ANCILLARY SERVICES MARKET

- The Department reviewed Xcel Electric's ASM charges and concludes that, although there is some fluctuation in various amounts, Xcel Electric's ASM charges for the AAA reporting period appear to be reasonable. As a result, the Department recommends that the Commission accept Xcel Electric's ASM reporting for the AAA reporting period.

- Department reviewed MP's ASM charges and concludes that they are reasonable. As a result, the Department recommends that the Commission accept MP's ASM reporting for the AAA reporting period.

- 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 for the AAA reporting period.

OTTER TAIL POWER COMPANY
Docket No: E999-AA-20-171

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/11/2020
Date Due: 03/23/2020
Date of Response: 03/12/2020
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Reference(s): Initial AAA Filing Part H, Section 3, Attachment K, Page 37-38

1. Did Otter Tail change any of the allocation methods used to allocate MISO Day 2 charges (revenues) between retail and asset-based wholesale during the 2018-2019 reporting period?

2. Did Otter Tail change any of the allocation methods used to allocate ASM costs (revenues) during the 2018-2019 reporting period?

Attachments: 0

Response:

1. Otter Tail did not make any changes to the allocation methods used to allocation MISO Day 2 charges (revenues) during the 2018-2019 reporting period.

2. Otter Tail did not make any changes to the allocation methods used to allocation ASM costs (revenues) during the 2018-2019 reporting period.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-20-171

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/11/2020
Date Due: 03/23/2020
Date of Response: 03/19/2020
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

Reference(s): Initial AAA Filing Part H, Section 3, Attachment K, Page 1-42

Please provide a narrative on why MISO Day 2 charges for Day-Ahead Non-Asset Energy Amount and Real-Time Congestion fluctuate from reporting period to reporting period.

Attachments: 0

Response:

MISO defines the Day-Ahead Non-Asset Energy Amount as the net charges and credits expressed in dollars 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. Otter Tail is the supplemental energy supplier for certain tribal, agency, and municipal loads within our service territory. The base energy for these loads is provided by the Western Area Power Administration (WAUE). WAUE is an SPP member, not a MISO member. For WAUE to serve these tribal, agency, and municipal loads within MISO, they must inject energy at the MISO/SPP interface node. MISO credits Otter Tail for the WAUE injection at the MISO/SPP interface (hence a non-asset energy source), and then charges Otter Tail when the load is withdrawn at the tribal, agency, and municipal loads. The WAUE energy schedules vary by month and by hour. Furthermore, the locational marginal price (LMP), which determines how much Otter Tail is credited for the WAUE energy injection, varies by hour based on market conditions. These ever-changing injection schedules and the attributable LMP pricing result in fluctuating amounts from reporting period to reporting period.

Real-Time Congestion fluctuation is the result of changing market conditions, generation levels, and loading levels. Congestion is one component of LMP pricing (along with energy and losses). Each pricing node has an LMP price with an associated congestion component. Real-Time Congestion is simply measuring, and quantifying, the difference between the Otter Tail load zone congestion and the Otter Tail generation congestion. Changing LMP market pricing is often driven by a change in the congestion component of the price. Any number of factors can cause congestion changes between our generation and load, including, but not limited to, changing weather patterns, transmission constraints or outages, loss of generation, increased loading, etc. It should also be noted that the real-time market is always truing up to deviations (dollars and MWs) that have already been settled in the day-ahead market. The combination of these factors results in a Real-Time Congestion charge that fluctuates significantly (including positive to negative) from one reporting period to another reporting period.

OTTER TAIL POWER COMPANY
Docket No: E999/AA-20-171

Response to: Minnesota Department of Commerce
Analyst: Michael Zajicek
Date Received: 03/11/2020
Date Due: 03/23/2020
Date of Response: 03/16/2020
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Information Request:

1. Please provide the actual costs and revenues and resulting actual asset-based margin for the 2018-2019 reporting period.

2. Please provide the amount of asset-based margins returned to ratepayers via the fuel clause for the 2018-2019 reporting period, or cite where in the report this information is provided. Please provide support for the development of asset-based margins.

Attachments: 3

Attachment 1 to IR MN-DOC-009.pdf
Attachment 2 to IR MN-DOC-009.pdf
Attachment 3 to IR MN-DOC-009.pdf

Response:

Attachment 1 to IR MN-DOC-09 contains the Asset Based margin costs and revenues for the time periods of July 2018 through June 2019 and July 2019 through December 2019. This information is also found in the initial filing Part H Section 3 Attachment K, Columns F through I.

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 the Otter Tail's Marketing book. One hundred percent of asset-based margins are passed through the fuel clause.

Attachment 2 to the IR MN-DOC-09 provides excerpts from the monthly reports generated from Otter Tail's system that provides the detail behind the MISO costs and revenues attributable to Otter Tail generation in excess of those levels necessary to serve retail load and accounted for in the Marketing Book. The summary page for July 2018 through June 2019 reflects the total MISO revenues of $7,061,674.09 and MISO costs of ($690,188.19). The summary page for July 2019 through December 2019 reflects the total MISO revenues of $2,548,695.21 and MISO costs of ($126,481.48). The MISO revenues and costs are also reported in Part H Section 3 Attachment K in Docket No. E999/AA-20-171.

Attachment 3 to IR MN-DOC-09 provides support detail for the associated fuel costs attributable to the Marketing Book sales. Total fuel costs for July 2018 through June 2019 were ($5,219,912.14). Total fuel costs for July 2019 through December 2019 were ($2,198,361.90).

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2018 - June 2019 Includes Any Adjustments

		(A)	(B)	(C)	(D)	(E)
			ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue
No.						
1	DA Mkt Admin Amount	555.01	0	$ (10,344.39)	0	$ -
2	DA Asset Energy Amount	555.02	0	$ -	120,543	$ 3,482,918.49
3	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (4,610.33)	0	$ 12.53
4	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 6,565.08
5	DA Schedule 24 Allocation Amount	555.33	0	$ (1,552.71)	0	$ -
6	RT Mkt Admin Amount	555.18	0	$ (14,290.37)	0	$ 121.11
7	RT Revenue Neutrality Uplift Amount	555.28	0	$ (30,283.31)	0	$ 11,378.06
8	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (20,450.54)	0	$ 581.46
9	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ 415,171.17
10	RT Schedule 23 Allocation Amount	555.34	0	$ (2,072.75)	0	$ 15.51
11	RT Price Volatility Make Whole Payment	555.42	0	$ (0.04)	0	$ 6,390.08
12	RT ASM Non-Excessive Energy Amount	555.55	(28,514)	$ (605,616.82)	123,846	$ 3,136,105.07
13	RT ASM Excessive Energy Amount	555.56	(48)	$ (966.93)	141	$ 2,415.53
14	NET MISO (Rev-Cost and MWh)		(28,562)	$ (690,188.19)	244,531	$ 7,061,674.09
15	Fuel Cost				(215,991)	$ (5,219,912.14)
16	**TOTAL ASSET BASED WHOLESALE**				**(22)**	**$ 1,151,573.76**

Explanation of Asset Based MWh deviation: On July 1, 2018 MISO implemented 5-minute real-time settlements for generation, going from hourly meter data to using 5-minute meter data in the settlement calculations. Extensive programming was needed for Otter Tail to report meter data on a 5-minute level, Otter Tail chose to continue reporting to MISO at the hourly level until programming could be completed. Once MISO implemented this change Otter Tail had an issue with their Progress software allocating the correct amounts for excessive and non-excessive energy charge types. A programming fix was made in October 2018 that corrected the allocating, however, this caused the Monthly Allocation Reports (excessive and non-excessive energy charge types) to report the volumes using MISO 5-minute data and the Marketing Book Costs report to use Otter Tail's hourly data. This resulted in the marketing book volumes to no longer be the same on both reports. Programming to report generation on a 5-minute basis is near completion. Once implemented Otter Tail may see these volumes match again. This does not impact revenues or costs in any way and 100% of Asset Based margins were passed through the fuel clause.

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2019 - December 2019 Includes Any Adjustments

		(A)	(B)	(C)	(D)	(E)
			ASSET BASED WHOLESALE			
No.	**Charge Type Description**	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**
1	DA Mkt Admin Amount	555.01	0	$ (1,252.80)	0	$ -
2	DA Asset Energy Amount	555.02	0	$ -	17,594	$ 463,283.72
3	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (2,206.89)	0	$ 50.45
4	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 2,717.57
5	DA Schedule 24 Allocation Amount	555.33	0	$ (205.52)	0	$ -
6	RT Mkt Admin Amount	555.18	0	$ (9,063.28)	0	$ 46.05
7	RT Revenue Neutrality Uplift Amount	555.28	0	$ (13,388.34)	0	$ 3,860.80
8	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (5,830.79)	0	$ 281.73
9	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ (1.03)	0	$ 37,974.54
10	RT Schedule 23 Allocation Amount	555.34	0	$ (1,353.33)	0	$ 6.73
11	RT Price Volatility Make Whole Payment	555.42	0	$ (7.92)	0	$ 3,499.51
12	RT ASM Non-Excessive Energy Amount	555.55	(4,651)	$ (93,163.98)	102,123	$ 2,031,819.55
13	RT ASM Excessive Energy Amount	555.56	(6)	$ (7.60)	354	$ 5,154.56
14	NET MISO (Rev-Cost and MWh)		(4,656)	$ (126,481.48)	120,070	$ 2,548,695.21
15	Fuel Cost				(115,219)	$ (2,198,361.90)
16	**TOTAL ASSET BASED WHOLESALE**				**195**	**$ 223,851.83**

Explanation of Asset Based MWh deviation: On July 1, 2018 MISO implemented 5-minute real-time settlements for generation, going from hourly meter data to using 5-minute meter data in the settlement calculations. Extensive programming was needed for Otter Tail to report meter data on a 5-minute level, Otter Tail chose to continue reporting to MISO at the hourly level until programming could be completed. Once MISO implemented this change Otter Tail had an issue with their Progress software allocating the correct amounts for excessive and non-excessive energy charge types. A programming fix was made in October 2018 that corrected the allocating, however, this caused the Monthly Allocation Reports (excessive and non-excessive energy charge types) to report the volumes using MISO 5-minute data and the Marketing Book Costs report to use Otter Tail's hourly data. This resulted in the marketing book volumes to no longer be the same on both reports. Programming to report generation on a 5-minute basis is near completion. Once implemented Otter Tail may see these volumes match again. This does not impact revenues or costs in any way and 100% of Asset Based margins were passed through the fuel clause.

Monthly Allocation Report - Monthly Plus Adjustments July 2018 - June 2019

Operating Dates: 4/1/2005 -- 6/20/2019
Settlement Dates: 6/29/2018 -- 6/27/2019

Charge Type	Portfolio	Account Cd		MW Rev	Dollar Rev	MW Cost	Dollar Cost
DA_ADMIN	MARKET	5035.0001.0962		0	$ -	0	$ (10,344.39)
DA_ASSET_EN	MARKET	5035.0002.0962		120,543	$ 3,482,918.49	0	$ -
DA_RSG_DIST	MARKET	5035.0010.0962		0	$ 12.53	0	$ (4,610.33)
DA_RSG_MWP	MARKET	5035.0011.0962		0	$ 6,565.08	0	$ -
DA_SCHD_24_ALC	MARKET	5035.0033.0962		0	$ -	0	$ (1,552.71)
RT_ADMIN	MARKET	5035.0018.0962		0	$ 121.11	0	$ (14,290.37)
RT_ASM_EXE	MARKET	5035.0056.0962		141	$ 2,415.53	(48)	$ (966.93)
RT_ASM_NXE	MARKET	5035.0055.0962		123,846	$ 3,136,105.07	(28,514)	$ (605,616.82)
RT_PV_MWP	MARKET	5035.0042.0962		0	$ 6,390.08	0	$ (0.04)
RT_RNU	MARKET	5035.0028.0962		0	$ 11,378.06	0	$ (30,283.31)
RT_RSG_DIST1	MARKET	5035.0029.0962		0	$ 581.46	0	$ (20,450.54)
RT_RSG_MWP	MARKET	5035.0030.0962		0	$ 415,171.17	0	$ -
RT_SCHD_24_ALC	MARKET	5035.0034.0962		0	$ 15.51	0	$ (2,072.75)
				244,531	$ 7,061,674.09	(28,562)	$ (690,188.19)

Monthly Allocation Report - Monthly Plus Adjustments July 2019 - December 2019

Operating Dates: 4/1/2005 -- 12/25/2019
Settlement Dates: 6/29/2018 -- 1/1/2020

Charge Type	Portfolio	Account Cd		MW Rev	Dollar Rev	MW Cost	Dollar Cost
DA_ADMIN	MARKET	5035.0001.0962		0	$ -	0	$ (1,252.80)
DA_ASSET_EN	MARKET	5035.0002.0962		17,594	$ 463,283.72	0	$ -
DA_RSG_DIST	MARKET	5035.0010.0962		0	$ 50.45	0	$ (2,206.89)
DA_RSG_MWP	MARKET	5035.0011.0962		0	$ 2,717.57	0	$ -
DA_SCHD_24_ALC	MARKET	5035.0033.0962		0	$ -	0	$ (205.52)
RT_ADMIN	MARKET	5035.0018.0962		0	$ 46.05	0	$ (9,063.28)
RT_ASM_EXE	MARKET	5035.0056.0962		354	$ 5,154.56	(6)	$ (7.60)
RT_ASM_NXE	MARKET	5035.0055.0962		102,123	$ 2,031,819.55	(4,651)	$ (93,163.98)
RT_PV_MWP	MARKET	5035.0042.0962		0	$ 3,499.51	0	$ (7.92)
RT_RNU	MARKET	5035.0028.0962		0	$ 3,860.80	0	$ (13,388.34)
RT_RSG_DIST1	MARKET	5035.0029.0962		0	$ 281.73	0	$ (5,830.79)
RT_RSG_MWP	MARKET	5035.0030.0962		0	$ 37,974.54	0	$ (1.03)
RT_SCHD_24_ALC	MARKET	5035.0034.0962		0	$ 6.73	0	$ (1,353.33)
				120,070	$ 2,548,695.21	(4,656)	$ (126,481.48)

Monthly Allocation Report - Monthly Plus Adjustments July 2018

Operating Dates: 4/1/2005 -- 7/23/2018

Settlement Dates: 6/29/2018 -- 7/30/2018

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	18,474.142	-1,426.89	18,474.142	-1,426.89
DA_ASSET_EN	MARKET	5035.0002.0962	18,474.142	645,119.34	0.000	0.00	18,474.142	645,119.34
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.32	0.000	-532.66	0.000	-532.34
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	1,891.22	0.000	0.00	0.000	1,891.22
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	18,474.142	-205.79	18,474.142	-205.79
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	16,429.978	-1,274.74	16,429.978	-1,274.74
RT_ASM_EXE	MARKET	5035.0056.0962	10.907	167.11	-27.718	-966.93	-16.811	-799.82
RT_ASM_NXE	MARKET	5035.0055.0962	13,666.000	307,497.84	-4,419.739	-79,796.74	9,246.261	227,701.10
RT_PV_MWP	MARKET	5035.0042.0962	0.000	2,397.77	0.000	0.00	0.000	2,397.77
RT_RNU	MARKET	5035.0028.0962	0.000	672.61	0.000	-3,445.42	0.000	-2,772.81
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	15.31	0.000	-3,360.22	0.000	-3,344.91
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	28,193.73	0.000	0.00	0.000	28,193.73
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	16,429.978	-183.61	16,429.978	-183.61

Monthly Allocation Report - Monthly Plus Adjustments August 2018

Operating Dates: 4/1/2005 -- 8/23/2018
Settlement Dates: 7/31/2018 -- 8/30/2018

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	22,122.251	-1,447.02	22,122.251	-1,447.02
DA_ASSET_EN	MARKET	5035.0002.0962	22,122.251	666,826.41	0.000	0.00	22,122.251	666,826.41
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.59	0.000	-419.65	0.000	-419.06
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	544.12	0.000	0.00	0.000	544.12
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	22,122.251	-246.23	22,122.251	-246.23
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	14,281.811	-942.48	14,281.811	-942.48
RT_ASM_EXE	MARKET	5035.0056.0962	4.729	106.39	0.000	0.00	4.729	106.39
RT_ASM_NXE	MARKET	5035.0055.0962	10,100.311	243,110.70	-4,184.269	-92,337.67	5,916.042	150,773.03
RT_PV_MWP	MARKET	5035.0042.0962	0.000	550.47	0.000	0.00	0.000	550.47
RT_RNU	MARKET	5035.0028.0962	0.000	1,448.48	0.000	-1,749.87	0.000	-301.39
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	11.04	0.000	-3,801.12	0.000	-3,790.08
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	8,120.40	0.000	0.00	0.000	8,120.40
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	14,281.811	-159.96	14,281.811	-159.96

Monthly Allocation Report - Monthly Plus Adjustments September 2018

Operating Dates: 4/1/2005 -- 9/20/2018

Settlement Dates: 8/31/2018 -- 9/27/2018

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	39,401.470	-3,288.03	39,401.470	-3,288.03
DA_ASSET_EN	MARKET	5035.0002.0962	39,401.470	1,012,471.30	0.000	0.00	39,401.470	1,012,471.30
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.16	0.000	-448.22	0.000	-448.06
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	3,202.99	0.000	0.00	0.000	3,202.99
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	39,401.470	-526.22	39,401.470	-526.22
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,118.713	-1,644.21	20,118.713	-1,644.21
RT_ASM_EXE	MARKET	5035.0056.0962	13.146	142.65	0.000	0.00	13.146	142.65
RT_ASM_NXE	MARKET	5035.0055.0962	9,166.472	214,759.09	-10,963.949	-230,339.44	-1,797.477	-15,580.35
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,065.31	0.000	0.00	0.000	1,065.31
RT_RNU	MARKET	5035.0028.0962	0.000	3,603.63	0.000	-3,910.04	0.000	-306.41
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	107.61	0.000	-4,168.93	0.000	-4,061.32
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	39,162.12	0.000	0.00	0.000	39,162.12
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	20,118.713	-258.72	20,118.713	-258.72

Monthly Allocation Report - Monthly Plus Adjustments October 2018

Operating Dates: 4/1/2005 -- 10/23/2018

Settlement Dates: 9/28/2018 -- 10/30/2018

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	11,920.359	-1,308.20	11,920.359	-1,308.20
DA_ASSET_EN	MARKET	5035.0002.0962	11,920.359	380,706.48	0.000	0.00	11,920.359	380,706.48
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.03	0.000	-326.66	0.000	-326.63
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	207.19	0.000	0.00	0.000	207.19
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	11,920.359	-182.71	11,920.359	-182.71
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	7,384.639	-772.53	7,384.639	-772.53
RT_ASM_EXE	MARKET	5035.0056.0962	3.100	59.99	0.000	0.00	3.100	59.99
RT_ASM_NXE	MARKET	5035.0055.0962	4,054.480	113,980.16	-1,716.240	-37,900.94	2,338.240	76,079.22
RT_PV_MWP	MARKET	5035.0042.0962	0.000	371.95	0.000	0.00	0.000	371.95
RT_RNU	MARKET	5035.0028.0962	0.000	1,198.19	0.000	-3,674.30	0.000	-2,476.11
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	42.36	0.000	-888.15	0.000	-845.79
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	10,155.71	0.000	0.00	0.000	10,155.71
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	7,384.639	-110.15	7,384.639	-110.15

Monthly Allocation Report - Monthly Plus Adjustments November 2018

Operating Dates: 4/1/2005 -- 11/22/2018

Settlement Dates: 10/31/2018 -- 11/29/2018

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	8,760.749	-1,039.94	8,760.749	-1,039.94
DA_ASSET_EN	MARKET	5035.0002.0962	8,760.749	224,838.08	0.000	0.00	8,760.749	224,838.08
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	4.18	0.000	-603.89	0.000	-599.71
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	235.42	0.000	0.00	0.000	235.42
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	8,760.103	-121.71	8,760.103	-121.71
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	15,797.657	-1,985.40	15,797.657	-1,985.40
RT_ASM_EXE	MARKET	5035.0056.0962	17.860	286.06	0.000	0.00	17.860	286.06
RT_ASM_NXE	MARKET	5035.0055.0962	10,552.600	279,464.50	-4,714.118	-113,437.17	5,838.482	166,027.33
RT_PV_MWP	MARKET	5035.0042.0962	0.000	159.63	0.000	0.00	0.000	159.63
RT_RNU	MARKET	5035.0028.0962	0.000	279.64	0.000	-2,191.28	0.000	-1,911.64
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	150.10	0.000	-2,080.64	0.000	-1,930.54
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	19,672.68	0.000	0.00	0.000	19,672.68
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	15,797.657	-235.14	15,797.657	-235.14

Monthly Allocation Report - Monthly Plus Adjustments December 2018

Operating Dates: 4/1/2005 -- 12/25/2018

Settlement Dates: 11/30/2018 -- 1/1/2019

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	7,179.513	-655.41	7,179.513	-655.41
DA_ASSET_EN	MARKET	5035.0002.0962	7,179.513	205,080.16	0.000	0.00	7,179.513	205,080.16
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.25	0.000	-607.43	0.000	-607.18
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	7,179.513	-92.96	7,179.513	-92.96
RT_ADMIN	MARKET	5035.0018.0962	0.000	5.27	8,543.275	-789.82	8,543.275	-784.55
RT_ASM_EXE	MARKET	5035.0056.0962	25.430	533.77	0.000	0.00	25.430	533.77
RT_ASM_NXE	MARKET	5035.0055.0962	6,828.630	208,217.82	-698.520	-16,486.50	6,130.110	191,731.32
RT_PV_MWP	MARKET	5035.0042.0962	0.000	208.88	0.000	-0.04	0.000	208.84
RT_RNU	MARKET	5035.0028.0962	0.000	936.62	0.000	-2,820.02	0.000	-1,883.40
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	129.88	0.000	-874.37	0.000	-744.49
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	16,626.27	0.000	0.00	0.000	16,626.27
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.80	8,543.275	-111.05	8,543.275	-110.25

Monthly Allocation Report - Monthly Plus Adjustments January 2019

Operating Dates: 4/1/2005 -- 1/23/2019
Settlement Dates: 1/2/2019 -- 1/30/2019

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	530.789	-40.77	530.789	-40.77
DA_ASSET_EN	MARKET	5035.0002.0962	530.789	13,580.65	0.000	0.00	530.789	13,580.65
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	1.27	0.000	-243.16	0.000	-241.89
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	6.82	0.000	0.00	0.000	6.82
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	530.789	-6.61	530.789	-6.61
RT_ADMIN	MARKET	5035.0018.0962	0.000	83.10	11,689.460	-835.95	11,689.460	-752.85
RT_ASM_EXE	MARKET	5035.0056.0962	15.850	298.58	0.000	0.00	15.850	298.58
RT_ASM_NXE	MARKET	5035.0055.0962	11,191.770	272,337.82	-137.990	-3,420.18	11,053.780	268,917.64
RT_PV_MWP	MARKET	5035.0042.0962	0.000	242.30	0.000	0.00	0.000	242.30
RT_RNU	MARKET	5035.0028.0962	0.000	817.82	0.000	-1,073.06	0.000	-255.24
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	14.47	0.000	-532.22	0.000	-517.75
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	12,638.10	0.000	0.00	0.000	12,638.10
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	9.65	11,689.460	-156.61	11,689.460	-146.96

Monthly Allocation Report - Monthly Plus Adjustments February 2019

Operating Dates: 4/1/2005 -- 2/20/2019

Settlement Dates: 1/31/2019 -- 2/27/2019

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	138.234	-10.16	138.234	-10.16
DA_ASSET_EN	MARKET	5035.0002.0962	138.234	4,999.38	0.000	0.00	138.234	4,999.38
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.41	0.000	-293.52	0.000	-293.11
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	138.234	-1.66	138.234	-1.66
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.11	11,011.285	-713.09	11,011.285	-712.98
RT_ASM_EXE	MARKET	5035.0056.0962	16.220	327.55	0.000	0.00	16.220	327.55
RT_ASM_NXE	MARKET	5035.0055.0962	10,859.880	482,937.96	-28.870	-767.54	10,831.010	482,170.42
RT_PV_MWP	MARKET	5035.0042.0962	0.000	153.99	0.000	0.00	0.000	153.99
RT_RNU	MARKET	5035.0028.0962	0.000	180.03	0.000	-4,385.48	0.000	-4,205.45
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	3.35	0.000	-1,524.93	0.000	-1,521.58
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	250,339.31	0.000	0.00	0.000	250,339.31
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.02	11,011.285	-132.22	11,011.285	-132.20

Monthly Allocation Report - Monthly Plus Adjustments March 2019

Operating Dates: 4/1/2005 -- 3/21/2019

Settlement Dates: 2/28/2019 -- 3/28/2019

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	4,982.126	-462.41	4,982.126	-462.41
DA_ASSET_EN	MARKET	5035.0002.0962	4,982.126	153,937.17	0.000	0.00	4,982.126	153,937.17
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	1.29	0.000	-356.42	0.000	-355.13
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4,982.126	-67.34	4,982.126	-67.34
RT_ADMIN	MARKET	5035.0018.0962	0.000	17.67	12,787.151	-1,122.19	12,787.151	-1,104.52
RT_ASM_EXE	MARKET	5035.0056.0962	4.310	86.07	0.000	0.00	4.310	86.07
RT_ASM_NXE	MARKET	5035.0055.0962	10,890.970	280,698.85	-654.610	-13,434.36	10,236.360	267,264.49
RT_PV_MWP	MARKET	5035.0042.0962	0.000	196.42	0.000	0.00	0.000	196.42
RT_RNU	MARKET	5035.0028.0962	0.000	301.63	0.000	-1,881.59	0.000	-1,579.96
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	13.29	0.000	-1,285.85	0.000	-1,272.56
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	15,601.28	0.000	0.00	0.000	15,601.28
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	2.86	12,787.151	-168.09	12,787.151	-165.23

Monthly Allocation Report - Monthly Plus Adjustments April 2019

Operating Dates: 4/1/2005 -- 4/22/2019

Settlement Dates: 3/29/2019 -- 4/29/2019

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	3,799.369	-358.33	3,799.369	-358.33
DA_ASSET_EN	MARKET	5035.0002.0962	3,799.369	93,747.56	0.000	0.00	3,799.369	93,747.56
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	1.77	0.000	-288.75	0.000	-286.98
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	217.70	0.000	0.00	0.000	217.70
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	3,799.369	-53.85	3,799.369	-53.85
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.42	9,924.223	-956.00	9,924.223	-955.58
RT_ASM_EXE	MARKET	5035.0056.0962	13.080	183.96	-20.420	0.00	-7.340	183.96
RT_ASM_NXE	MARKET	5035.0055.0962	8,517.980	178,648.73	-569.250	-12,485.64	7,948.730	166,163.09
RT_PV_MWP	MARKET	5035.0042.0962	0.000	345.60	0.000	0.00	0.000	345.60
RT_RNU	MARKET	5035.0028.0962	0.000	378.95	0.000	-1,537.69	0.000	-1,158.74
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	13.92	0.000	-374.80	0.000	-360.88
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	10,851.09	0.000	0.00	0.000	10,851.09
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.08	9,924.223	-147.16	9,924.223	-147.08

Monthly Allocation Report - Monthly Plus Adjustments May 2019

Operating Dates: 4/1/2005 -- 5/23/2019

Settlement Dates: 4/30/2019 -- 5/30/2019

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	3,230.031	-306.82	3,230.031	-306.82
DA_ASSET_EN	MARKET	5035.0002.0962	3,230.031	81,523.54	0.000	0.00	3,230.031	81,523.54
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.52	0.000	-230.70	0.000	-230.18
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	259.62	0.000	0.00	0.000	259.62
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	3,230.031	-47.58	3,230.031	-47.58
RT_ADMIN	MARKET	5035.0018.0962	0.000	14.54	10,861.022	-1,101.85	10,861.022	-1,087.31
RT_ASM_EXE	MARKET	5035.0056.0962	16.230	223.40	0.000	0.00	16.230	223.40
RT_ASM_NXE	MARKET	5035.0055.0962	7,966.840	157,874.06	-418.770	-5,053.01	7,548.070	152,821.05
RT_PV_MWP	MARKET	5035.0042.0962	0.000	518.68	0.000	0.00	0.000	518.68
RT_RNU	MARKET	5035.0028.0962	0.000	337.51	0.000	-1,649.17	0.000	-1,311.66
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	17.49	0.000	-320.93	0.000	-303.44
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	161.46	0.000	0.00	0.000	161.46
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	2.10	10,861.022	-165.18	10,861.022	-163.08

Monthly Allocation Report - Monthly Plus Adjustments June 2019

Operating Dates: 4/1/2005 -- 6/20/2019
Settlement Dates: 5/31/2019 -- 6/27/2019

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	4.450	-0.41	4.450	-0.41
DA_ASSET_EN	MARKET	5035.0002.0962	4.450	88.42	0.000	0.00	4.450	88.42
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	1.74	0.000	-259.27	0.000	-257.53
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4.450	-0.05	4.450	-0.05
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,051.858	-2,152.11	20,051.858	-2,152.11
RT_ASM_NXE	MARKET	5035.0055.0962	20,050.460	396,577.54	-7.590	-157.63	20,042.870	396,419.91
RT_PV_MWP	MARKET	5035.0042.0962	0.000	179.08	0.000	0.00	0.000	179.08
RT_RNU	MARKET	5035.0028.0962	0.000	1,222.95	0.000	-1,965.39	0.000	-742.44
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	62.64	0.000	-1,238.38	0.000	-1,175.74
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	3,649.02	0.000	0.00	0.000	3,649.02
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	20,051.858	-244.86	20,051.858	-244.86

Monthly Allocation Report - Monthly Plus Adjustments July 2019

Operating Dates: 4/1/2005 -- 7/23/2019

Settlement Dates: 6/28/2019 -- 7/30/2019

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	109.476	-8.31	109.476	-8.31
DA_ASSET_EN	MARKET	5035.0002.0962	109.476	4,478.13	0.000	0.00	109.476	4,478.13
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	41.50	0.000	-448.84	0.000	-407.34
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	109.476	-1.25	109.476	-1.25
RT_ADMIN	MARKET	5035.0018.0962	0.000	2.63	22,535.714	-1,892.81	22,535.714	-1,890.18
RT_ASM_EXE	MARKET	5035.0056.0962	20.290	278.06	0.000	0.00	20.290	278.06
RT_ASM_NXE	MARKET	5035.0055.0962	22,551.210	538,653.02	-4.100	-108.68	22,547.110	538,544.34
RT_PV_MWP	MARKET	5035.0042.0962	0.000	1,142.67	0.000	-7.92	0.000	1,134.75
RT_RNU	MARKET	5035.0028.0962	0.000	427.09	0.000	-2,991.75	0.000	-2,564.66
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	33.38	0.000	-2,412.12	0.000	-2,378.74
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	17,863.27	0.000	0.00	0.000	17,863.27
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.43	22,535.714	-268.01	22,535.714	-267.58

Monthly Allocation Report - Monthly Plus Adjustments August 2019

Operating Dates: 4/1/2005 -- 8/22/2019

Settlement Dates: 7/31/2019 -- 8/29/2019

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	5,491.240	-287.02	5,491.240	-287.02
DA_ASSET_EN	MARKET	5035.0002.0962	5,491.240	174,866.44	0.000	0.00	5,491.240	174,866.44
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	8.64	0.000	-287.03	0.000	-278.39
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	905.11	0.000	0.00	0.000	905.11
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	5,491.240	-61.23	5,491.240	-61.23
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	20,916.211	-1,351.87	20,916.211	-1,351.87
RT_ASM_EXE	MARKET	5035.0056.0962	197.770	3,153.76	0.000	0.00	197.770	3,153.76
RT_ASM_NXE	MARKET	5035.0055.0962	18,476.210	360,124.31	-1,341.620	-25,644.54	17,134.590	334,479.77
RT_PV_MWP	MARKET	5035.0042.0962	0.000	915.84	0.000	0.00	0.000	915.84
RT_RNU	MARKET	5035.0028.0962	0.000	426.18	0.000	-2,639.28	0.000	-2,213.10
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	154.23	0.000	-1,255.20	0.000	-1,100.97
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	1,693.83	0.000	0.00	0.000	1,693.83
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	20,916.211	-249.52	20,916.211	-249.52

Monthly Allocation Report - Monthly Plus Adjustments September 2019

Operating Dates: 4/1/2005 -- 9/22/2019

Settlement Dates: 8/30/2019 -- 9/29/2019

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	6,415.764	-496.25	6,415.764	-496.25
DA_ASSET_EN	MARKET	5035.0002.0962	6,415.764	158,160.59	0.000	0.00	6,415.764	158,160.59
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.00	0.000	-327.78	0.000	-327.78
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	1,731.75	0.000	0.00	0.000	1,731.75
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	6,415.764	-76.09	6,415.764	-76.09
RT_ADMIN	MARKET	5035.0018.0962	0.000	5.01	23,226.031	-1,654.87	23,226.031	-1,649.86
RT_ASM_EXE	MARKET	5035.0056.0962	73.760	920.19	0.000	0.00	73.760	920.19
RT_ASM_NXE	MARKET	5035.0055.0962	20,229.990	367,309.26	-623.630	-11,263.05	19,606.360	356,046.21
RT_PV_MWP	MARKET	5035.0042.0962	0.000	524.30	0.000	0.00	0.000	524.30
RT_RNU	MARKET	5035.0028.0962	0.000	556.66	0.000	-1,417.62	0.000	-860.96
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	28.24	0.000	-754.44	0.000	-726.20
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	3,508.31	0.000	0.00	0.000	3,508.31
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	1.15	23,226.031	-274.97	23,226.031	-273.82

Monthly Allocation Report - Monthly Plus Adjustments October 2019

Operating Dates: 4/1/2005 -- 10/23/2019
Settlement Dates: 9/30/2019 -- 10/30/2019

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	4,372.328	-352.69	4,372.328	-352.69
DA_ASSET_EN	MARKET	5035.0002.0962	4,372.328	96,157.35	0.000	0.00	4,372.328	96,157.35
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.02	0.000	-235.57	0.000	-235.55
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	30.04	0.000	0.00	0.000	30.04
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	4,372.328	-52.22	4,372.328	-52.22
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.61	11,184.346	-1,041.96	11,184.346	-1,041.35
RT_ASM_EXE	MARKET	5035.0056.0962	16.090	141.36	-0.360	-7.60	15.730	133.76
RT_ASM_NXE	MARKET	5035.0055.0962	7,800.520	103,263.49	-2,086.080	-40,066.84	5,714.440	63,196.65
RT_PV_MWP	MARKET	5035.0042.0962	0.000	301.67	0.000	0.00	0.000	301.67
RT_RNU	MARKET	5035.0028.0962	0.000	583.81	0.000	-1,544.77	0.000	-960.96
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	27.45	0.000	-269.47	0.000	-242.02
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	2,678.82	0.000	-0.42	0.000	2,678.40
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.11	11,184.346	-143.19	11,184.346	-143.08

Monthly Allocation Report - Monthly Plus Adjustments November 2019

Operating Dates: 4/1/2005 -- 11/21/2019
Settlement Dates: 10/31/2019 -- 11/28/2019

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	916.192	-82.83	916.192	-82.83
DA_ASSET_EN	MARKET	5035.0002.0962	916.192	21,325.66	0.000	0.00	916.192	21,325.66
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.03	0.000	-425.18	0.000	-425.15
DA_RSG_MWP	MARKET	5035.0011.0962	0.000	50.67	0.000	0.00	0.000	50.67
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	915.881	-11.22	915.881	-11.22
RT_ADMIN	MARKET	5035.0018.0962	0.000	0.00	14,673.401	-1,333.71	14,673.401	-1,333.71
RT_ASM_EXE	MARKET	5035.0056.0962	21.480	271.68	-5.180	0.00	16.300	271.68
RT_ASM_NXE	MARKET	5035.0055.0962	14,381.020	327,707.16	-120.580	-2,445.60	14,260.440	325,261.56
RT_PV_MWP	MARKET	5035.0042.0962	0.000	124.81	0.000	0.00	0.000	124.81
RT_RNU	MARKET	5035.0028.0962	0.000	1,307.70	0.000	-2,062.96	0.000	-755.26
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	28.28	0.000	-581.14	0.000	-552.86
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	7,178.01	0.000	-0.61	0.000	7,177.40
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	0.00	14,673.401	-180.47	14,673.401	-180.47

Monthly Allocation Report - Monthly Plus Adjustments December 2019

Operating Dates: 4/1/2005 -- 12/25/2019
Settlement Dates: 11/29/2019 -- 1/1/2020

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	288.812	-25.70	288.812	-25.70
DA_ASSET_EN	MARKET	5035.0002.0962	288.812	8,295.55	0.000	0.00	288.812	8,295.55
DA_RSG_DIST	MARKET	5035.0010.0962	0.000	0.26	0.000	-482.49	0.000	-482.23
DA_SCHD_24_ALC	MARKET	5035.0033.0962	0.000	0.00	288.812	-3.51	288.812	-3.51
RT_ADMIN	MARKET	5035.0018.0962	0.000	37.80	18,808.326	-1,788.06	18,808.326	-1,750.26
RT_ASM_EXE	MARKET	5035.0056.0962	24.530	389.51	0.000	0.00	24.530	389.51
RT_ASM_NXE	MARKET	5035.0055.0962	18,683.810	334,762.31	-474.600	-13,635.27	18,209.210	321,127.04
RT_PV_MWP	MARKET	5035.0042.0962	0.000	490.22	0.000	0.00	0.000	490.22
RT_RNU	MARKET	5035.0028.0962	0.000	559.36	0.000	-2,731.96	0.000	-2,172.60
RT_RSG_DIST1	MARKET	5035.0029.0962	0.000	10.15	0.000	-558.42	0.000	-548.27
RT_RSG_MWP	MARKET	5035.0030.0962	0.000	5,052.30	0.000	0.00	0.000	5,052.30
RT_SCHD_24_ALC	MARKET	5035.0034.0962	0.000	5.04	18,808.326	-237.17	18,808.326	-232.13

Marketing Book Costs - Monthly Adjustments July 2018 - June 2019

Operating Dates: 6/22/2018 -- 6/20/2019
Settlement Dates: 6/29/2018 -- 6/27/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	52,340.271	$1,211,903.40	($977,760.33)	$234,143.07
	Real Time	52,603.815	$1,025,421.12	($1,098,356.45)	($72,935.33)
	Total:	**104,944.086**	**$2,237,324.52**	**($2,076,116.78)**	**$161,207.74**
OTP.COYOT1	Day Ahead	8,556.007	$179,458.35	($99,465.97)	$79,992.38
	Real Time	18,056.648	$422,654.78	($203,570.67)	$219,084.11
	Total:	**26,612.655**	**$602,113.13**	**($303,036.64)**	**$299,076.49**
OTP.HETLA	Day Ahead	8.000	$270.72	($2,842.96)	($2,572.24)
	Real Time	403.460	$26,371.14	($152,200.03)	($125,828.89)
	Total:	**411.460**	**$26,641.86**	**($155,042.99)**	**($128,401.13)**
OTP.HOOTL2	Day Ahead	13,038.224	$395,452.94	($314,831.85)	$80,621.09
	Real Time	3,322.442	$92,613.39	($82,436.92)	$10,176.47
	Total:	**16,360.666**	**$488,066.33**	**($397,268.77)**	**$90,797.56**
OTP.HOOTL3	Day Ahead	26,555.897	$856,015.91	($655,403.82)	$200,612.09
	Real Time	6,441.249	$355,480.53	($161,111.66)	$194,368.87
	Total:	**32,997.146**	**$1,211,496.44**	**($816,515.48)**	**$394,980.96**
OTP.JAMSPK1	Day Ahead	44.000	$1,742.58	($17,624.36)	($15,881.78)
	Real Time	289.909	$23,304.03	($141,464.88)	($118,160.85)
	Total:	**333.909**	**$25,046.61**	**($159,089.24)**	**($134,042.63)**
OTP.JAMSPK2	Day Ahead	68.000	$2,057.64	($23,944.08)	($21,886.44)
	Real Time	274.477	$23,893.65	($134,967.77)	($111,074.12)
	Total:	**342.477**	**$25,951.29**	**($158,911.85)**	**($132,960.56)**
OTP.SLWAYO1	Day Ahead	19,933.084	$836,016.95	($625,812.98)	$210,203.97
	Real Time	14,055.140	$528,375.97	($528,117.41)	$258.56
	Total:	**33,988.224**	**$1,364,392.92**	**($1,153,930.39)**	**$210,462.53**
Day Ahead	**Total**	**120,543.483**	**$3,482,918.49**	**($2,717,686.35)**	**$765,232.14**
Real Time	**Total**	**95,447.140**	**$2,498,114.61**	**($2,502,225.79)**	**($4,111.18)**
Margins	**Total**	**215,990.623**	**$5,981,033.10**	**($5,219,912.14)**	**$761,120.96**

Marketing Book Costs - Monthly Adjustments July 2019 - December 2019

Operating Dates: 6/21/2019 -- 12/25/2019
Settlement Dates: 6/28/2019 -- 1/1/2020

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	8,832.724	$185,280.21	($160,409.33)	$24,870.88
	Real Time	54,695.688	$994,375.32	($1,092,685.49)	($98,310.17)
	Total:	**63,528.412**	**$1,179,655.53**	**($1,253,094.82)**	**($73,439.29)**
OTP.COYOT1	Day Ahead	625.819	$8,732.75	($8,496.70)	$236.05
	Real Time	31,600.095	$549,790.38	($378,431.24)	$171,359.14
	Total:	**32,225.914**	**$558,523.13**	**($386,927.94)**	**$171,595.19**
OTP.HETLA	Day Ahead	11.340	$330.02	($4,947.53)	($4,617.51)
	Real Time	61.431	$1,368.06	($21,171.75)	($19,803.69)
	Total:	**72.771**	**$1,698.08**	**($26,119.28)**	**($24,421.20)**
OTP.HOOTL2	Day Ahead	693.264	$21,809.05	($16,942.06)	$4,866.99
	Real Time	1,580.160	$41,287.18	($39,237.48)	$2,049.70
	Total:	**2,273.424**	**$63,096.23**	**($56,179.54)**	**$6,916.69**
OTP.HOOTL3	Day Ahead	1,637.247	$55,140.00	($40,725.21)	$14,414.79
	Real Time	5,406.971	$164,609.79	($135,358.94)	$29,250.85
	Total:	**7,044.218**	**$219,749.79**	**($176,084.15)**	**$43,665.64**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	48.019	$1,095.23	($16,288.89)	($15,193.66)
	Total:	**48.019**	**$1,095.23**	**($16,288.89)**	**($15,193.66)**
OTP.JAMSPK2	Day Ahead	24.000	$687.60	($10,131.12)	($9,443.52)
	Real Time	55.052	$1,048.45	($19,874.76)	($18,826.31)
	Total:	**79.052**	**$1,736.05**	**($30,005.88)**	**($28,269.83)**
OTP.SLWAYO1	Day Ahead	5,769.418	$191,304.09	($138,475.21)	$52,828.88
	Real Time	4,177.977	$162,391.91	($115,186.19)	$47,205.72
	Total:	**9,947.395**	**$353,696.00**	**($253,661.40)**	**$100,034.60**
Day Ahead	**Total**	**17,593.812**	**$463,283.72**	**($380,127.16)**	**$83,156.56**
Real Time	**Total**	**97,625.393**	**$1,915,966.32**	**($1,818,234.74)**	**$97,731.58**
Margins	**Total**	**115,219.205**	**$2,379,250.04**	**($2,198,361.90)**	**$180,888.14**

Marketing Book Costs - Monthly July 2018

Operating Dates: 6/22/2018 -- 7/23/2018

Settlement Dates: 6/29/2018 -- 7/30/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	4,028.055	$110,103.82	-$87,290.04	$22,813.78
	Real Time	7,793.042	$174,895.50	-$169,655.47	$5,240.03
	Total:	**11,821.097**	**$284,999.32**	**-$256,945.51**	**$28,053.81**
OTP.COYOT1	Day Ahead	35.086	$512.87	-$385.63	$127.24
	Real Time	662.466	$8,506.07	-$7,362.93	$1,143.14
	Total:	**697.552**	**$9,018.94**	**-$7,748.56**	**$1,270.38**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.472	$15.15	-$193.15	-$178.00
	Total:	**0.472**	**$15.15**	**-$193.15**	**-$178.00**
OTP.HOOTL2	Day Ahead	2,544.623	$80,166.11	-$61,306.71	$18,859.40
	Real Time	-46.702	-$374.56	$1,024.90	$650.34
	Total:	**2,497.921**	**$79,791.55**	**-$60,281.81**	**$19,509.74**
OTP.HOOTL3	Day Ahead	5,576.725	$186,811.92	-$137,878.42	$48,933.50
	Real Time	139.667	$3,939.11	-$3,604.72	$334.39
	Total:	**5,716.392**	**$190,751.03**	**-$141,483.14**	**$49,267.89**
OTP.JAMSPK1	Day Ahead	38.000	$1,625.52	-$14,289.32	-$12,663.80
	Real Time	14.652	$137.97	-$5,030.32	-$4,892.35
	Total:	**52.652**	**$1,763.49**	**-$19,319.64**	**-$17,556.15**
OTP.JAMSPK2	Day Ahead	60.000	$1,779.40	-$20,049.60	-$18,270.20
	Real Time	54.236	$2,101.07	-$16,569.22	-$14,468.15
	Total:	**114.236**	**$3,880.47**	**-$36,618.82**	**-$32,738.35**
OTP.SLWAYO1	Day Ahead	6,191.653	$264,119.70	-$181,734.97	$82,384.73
	Real Time	611.617	$35,265.46	-$11,537.88	$23,727.58
	Total:	**6,803.270**	**$299,385.16**	**-$193,272.85**	**$106,112.31**
Day Ahead	**Total**	**18,474.142**	**$645,119.34**	**-$502,934.69**	**$142,184.65**
Real Time	**Total**	**9,229.450**	**$224,485.77**	**-$212,928.79**	**$11,556.98**
Margins	**Total**	**27,703.592**	**$869,605.11**	**-$715,863.48**	**$153,741.63**

Marketing Book Costs - Monthly August 2018

Operating Dates: 7/24/2018 -- 8/23/2018

Settlement Dates: 7/31/2018 -- 8/30/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	6,559.996	$154,412.02	-$143,354.12	$11,057.90
	Real Time	4,425.586	$94,441.00	-$98,526.12	-$4,085.12
	Total:	**10,985.582**	**$248,853.02**	**-$241,880.24**	**$6,972.78**
OTP.COYOT1	Day Ahead	1,107.015	$21,102.03	-$15,881.26	$5,220.77
	Real Time	763.434	$18,472.49	-$8,483.52	$9,988.97
	Total:	**1,870.449**	**$39,574.52**	**-$24,364.78**	**$15,209.74**
OTP.HETLA	Day Ahead	8.000	$270.72	-$2,842.96	-$2,572.24
	Real Time	0.384	$14.36	-$147.55	-$133.19
	Total:	**8.384**	**$285.08**	**-$2,990.51**	**-$2,705.43**
OTP.HOOTL2	Day Ahead	3,317.436	$97,488.51	-$79,929.51	$17,559.00
	Real Time	-331.371	-$9,950.97	$7,975.29	-$1,975.68
	Total:	**2,986.065**	**$87,537.54**	**-$71,954.22**	**$15,583.32**
OTP.HOOTL3	Day Ahead	6,156.723	$191,087.69	-$152,213.31	$38,874.38
	Real Time	-146.668	-$3,595.16	$3,457.94	-$137.22
	Total:	**6,010.055**	**$187,492.53**	**-$148,755.37**	**$38,737.16**
OTP.SLWAYO1	Day Ahead	4,973.081	$202,465.44	-$157,284.87	$45,180.57
	Real Time	1,209.406	$46,853.51	-$40,143.26	$6,710.25
	Total:	**6,182.487**	**$249,318.95**	**-$197,428.13**	**$51,890.82**
Day Ahead	**Total**	**22,122.251**	**$666,826.41**	**-$551,506.03**	**$115,320.38**
Real Time	**Total**	**5,920.771**	**$146,235.23**	**-$135,867.22**	**$10,368.01**
Margins	**Total**	**28,043.022**	**$813,061.64**	**-$687,373.25**	**$125,688.39**

Marketing Book Costs - Monthly September 2018

Operating Dates: 8/24/2018 -- 9/20/2018

Settlement Dates: 8/31/2018 -- 9/27/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	26,759.488	$598,640.98	-$475,968.63	$122,672.35
	Real Time	-4,515.744	-$97,160.41	$82,761.60	-$14,398.81
	Total:	**22,243.744**	**$501,480.57**	**-$393,207.03**	**$108,273.54**
OTP.COYOT1	Day Ahead	1,822.519	$29,920.87	-$20,623.05	$9,297.82
	Real Time	789.982	$16,527.75	-$8,553.55	$7,974.20
	Total:	**2,612.501**	**$46,448.62**	**-$29,176.60**	**$17,272.02**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	19.397	$1,276.28	-$7,978.19	-$6,701.91
	Total:	**19.397**	**$1,276.28**	**-$7,978.19**	**-$6,701.91**
OTP.HOOTL2	Day Ahead	2,535.090	$81,299.68	-$61,104.46	$20,195.22
	Real Time	230.458	$5,559.65	-$5,816.62	-$256.97
	Total:	**2,765.548**	**$86,859.33**	**-$66,921.08**	**$19,938.25**
OTP.HOOTL3	Day Ahead	4,372.570	$145,412.53	-$108,132.55	$37,279.98
	Real Time	374.349	$10,289.87	-$9,574.37	$715.50
	Total:	**4,746.919**	**$155,702.40**	**-$117,706.92**	**$37,995.48**
OTP.JAMSPK1	Day Ahead	6.000	$117.06	-$3,335.04	-$3,217.98
	Real Time	23.812	$1,075.59	-$12,312.35	-$11,236.76
	Total:	**29.812**	**$1,192.65**	**-$15,647.39**	**-$14,454.74**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	21.556	$1,057.73	-$11,951.44	-$10,893.71
	Total:	**21.556**	**$1,057.73**	**-$11,951.44**	**-$10,893.71**
OTP.SLWAYO1	Day Ahead	3,905.803	$157,080.18	-$126,219.77	$30,860.41
	Real Time	1,271.859	$46,077.81	-$40,891.31	$5,186.50
	Total:	**5,177.662**	**$203,157.99**	**-$167,111.08**	**$36,046.91**
Day Ahead	**Total**	**39,401.470**	**$1,012,471.30**	**-$795,383.50**	**$217,087.80**
Real Time	**Total**	**-1,784.331**	**-$15,295.73**	**-$14,316.23**	**-$29,611.96**
Margins	**Total**	**37,617.139**	**$997,175.57**	**-$809,699.73**	**$187,475.84**

Marketing Book Costs - Monthly October 2018

Operating Dates: 9/21/2018 -- 10/23/2018

Settlement Dates: 9/28/2018 -- 10/30/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.COYOT1	Day Ahead	4,186.013	$96,210.26	-$46,813.12	$49,397.14
	Real Time	951.425	$21,984.36	-$10,774.13	$11,210.23
	Total:	**5,137.438**	**$118,194.62**	**-$57,587.25**	**$60,607.37**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	161.089	$4,011.79	-$46,693.64	-$42,681.85
	Total:	**161.089**	**$4,011.79**	**-$46,693.64**	**-$42,681.85**
OTP.HOOTL2	Day Ahead	1,634.444	$50,272.62	-$39,411.14	$10,861.48
	Real Time	1.199	$20.10	-$147.04	-$126.94
	Total:	**1,635.643**	**$50,292.72**	**-$39,558.18**	**$10,734.54**
OTP.HOOTL3	Day Ahead	2,852.501	$92,112.77	-$70,564.43	$21,548.34
	Real Time	270.869	$8,006.09	-$6,830.74	$1,175.35
	Total:	**3,123.370**	**$100,118.86**	**-$77,395.17**	**$22,723.69**
OTP.JAMSPK2	Day Ahead	8.000	$278.24	-$3,894.48	-$3,616.24
	Real Time	1.021	$38.25	-$548.33	-$510.08
	Total:	**9.021**	**$316.49**	**-$4,442.81**	**-$4,126.32**
OTP.SLWAYO1	Day Ahead	3,239.401	$141,832.59	-$106,498.04	$35,334.55
	Real Time	955.536	$37,404.80	-$31,499.41	$5,905.39
	Total:	**4,194.937**	**$179,237.39**	**-$137,997.45**	**$41,239.94**
Day Ahead	**Total**	**11,920.359**	**$380,706.48**	**-$267,181.21**	**$113,525.27**
Real Time	**Total**	**2,341.139**	**$71,465.39**	**-$96,493.29**	**-$25,027.90**
Margins	**Total**	**14,261.498**	**$452,171.87**	**-$363,674.50**	**$88,497.37**

Marketing Book Costs - Monthly November 2018

Operating Dates: 10/24/2018 -- 11/22/2018

Settlement Dates: 10/31/2018 -- 11/29/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	5,330.865	$126,374.60	-$88,695.21	$37,679.39
	Real Time	-3,703.545	-$85,666.78	$70,446.03	-$15,220.75
	Total:	**1,627.320**	**$40,707.82**	**-$18,249.18**	**$22,458.64**
OTP.COYOT1	Day Ahead	1,361.253	$30,713.27	-$15,278.26	$15,435.01
	Real Time	6,872.717	$155,821.87	-$77,987.94	$77,833.93
	Total:	**8,233.970**	**$186,535.14**	**-$93,266.20**	**$93,268.94**
OTP.HOOTL2	Day Ahead	400.353	$11,424.87	-$9,598.31	$1,826.56
	Real Time	61.769	$4,219.65	-$1,409.27	$2,810.38
	Total:	**462.122**	**$15,644.52**	**-$11,007.58**	**$4,636.94**
OTP.HOOTL3	Day Ahead	1,418.095	$45,159.87	-$34,852.66	$10,307.21
	Real Time	356.847	$7,599.15	-$8,874.45	-$1,275.30
	Total:	**1,774.942**	**$52,759.02**	**-$43,727.11**	**$9,031.91**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.000	$0.00	$459.58	$459.58
	Total:	**0.000**	**$0.00**	**$459.58**	**$459.58**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.048	$22.53	-$562.28	-$539.75
	Total:	**1.048**	**$22.53**	**-$562.28**	**-$539.75**
OTP.SLWAYO1	Day Ahead	250.183	$11,165.47	-$9,260.81	$1,904.66
	Real Time	2,266.728	$82,583.62	-$91,985.72	-$9,402.10
	Total:	**2,516.911**	**$93,749.09**	**-$101,246.53**	**-$7,497.44**
Day Ahead	**Total**	**8,760.749**	**$224,838.08**	**-$157,685.25**	**$67,152.83**
Real Time	**Total**	**5,855.564**	**$164,580.04**	**-$109,914.05**	**$54,665.99**
Margins	**Total**	**14,616.313**	**$389,418.12**	**-$267,599.30**	**$121,818.82**

Marketing Book Costs - Monthly Adjustments November 2018

Operating Dates: 4/1/2005 -- 10/23/2018

Settlement Dates: 10/31/2018 -- 11/29/2018

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.811	$16.99	-$14.23	$2.76
	Total:	**0.811**	**$16.99**	**-$14.23**	**$2.76**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.174	-$8.73	$2.36	-$6.37
	Total:	**-0.174**	**-$8.73**	**$2.36**	**-$6.37**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.637**	**$8.26**	**-$11.87**	**-$3.61**
Margins	**Total**	**0.637**	**$8.26**	**-$11.87**	**-$3.61**

Marketing Book Costs - Monthly December 2018

Operating Dates: 11/23/2018 -- 12/25/2018

Settlement Dates: 11/30/2018 -- 1/1/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	3,290.807	$78,199.38	-$63,485.63	$14,713.75
	Real Time	2,196.824	$46,060.39	-$42,377.69	$3,682.70
	Total:	**5,487.631**	**$124,259.77**	**-$105,863.32**	**$18,396.45**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1,679.883	$42,932.48	-$19,206.67	$23,725.81
	Total:	**1,679.883**	**$42,932.48**	**-$19,206.67**	**$23,725.81**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.157	$1.69	-$51.60	-$49.91
	Total:	**0.157**	**$1.69**	**-$51.60**	**-$49.91**
OTP.HOOTL2	Day Ahead	824.151	$23,883.11	-$19,712.41	$4,170.70
	Real Time	169.456	$4,695.69	-$3,992.48	$703.21
	Total:	**993.607**	**$28,578.80**	**-$23,704.89**	**$4,873.91**
OTP.HOOTL3	Day Ahead	2,822.281	$90,305.93	-$69,011.27	$21,294.66
	Real Time	275.145	$7,381.17	-$6,758.20	$622.97
	Total:	**3,097.426**	**$97,687.10**	**-$75,769.47**	**$21,917.63**
OTP.SLWAYO1	Day Ahead	242.274	$12,691.74	-$10,930.88	$1,760.86
	Real Time	1,833.722	$87,476.03	-$91,968.48	-$4,492.45
	Total:	**2,075.996**	**$100,167.77**	**-$102,899.36**	**-$2,731.59**
Day Ahead	**Total**	**7,179.513**	**$205,080.16**	**-$163,140.19**	**$41,939.97**
Real Time	**Total**	**6,155.187**	**$188,547.45**	**-$164,355.12**	**$24,192.33**
Margins	**Total**	**13,334.700**	**$393,627.61**	**-$327,495.31**	**$66,132.30**

Marketing Book Costs - Monthly   January 2019

Operating Dates: 12/26/2018 -- 1/23/2019
Settlement Dates: 1/2/2019 -- 1/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	272.237	$5,732.69	-$5,402.85	$329.84
	Real Time	7,666.257	$159,815.63	-$168,581.79	-$8,766.16
	Total:	**7,938.494**	**$165,548.32**	**-$173,984.64**	**-$8,436.32**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	452.451	$12,214.63	-$5,113.00	$7,101.63
	Total:	**452.451**	**$12,214.63**	**-$5,113.00**	**$7,101.63**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	4.872	$63.38	-$1,481.72	-$1,418.34
	Total:	**4.872**	**$63.38**	**-$1,481.72**	**-$1,418.34**
OTP.HOOTL2	Day Ahead	142.072	$3,385.49	-$3,397.48	-$11.99
	Real Time	984.366	$24,624.69	-$24,398.58	$226.11
	Total:	**1,126.438**	**$28,010.18**	**-$27,796.06**	**$214.12**
OTP.HOOTL3	Day Ahead	20.427	$532.47	-$502.71	$29.76
	Real Time	388.397	$9,948.42	-$9,836.06	$112.36
	Total:	**408.824**	**$10,480.89**	**-$10,338.77**	**$142.12**
OTP.SLWAYO1	Day Ahead	96.053	$3,930.00	-$3,286.94	$643.06
	Real Time	1,601.534	$59,398.86	-$61,654.35	-$2,255.49
	Total:	**1,697.587**	**$63,328.86**	**-$64,941.29**	**-$1,612.43**
Day Ahead	**Total**	**530.789**	**$13,580.65**	**-$12,589.98**	**$990.67**
Real Time	**Total**	**11,097.877**	**$266,065.61**	**-$271,065.50**	**-$4,999.89**
Margins	**Total**	**11,628.666**	**$279,646.26**	**-$283,655.48**	**-$4,009.22**

Marketing Book Costs - Monthly Adjustments January 2019

Operating Dates: 4/1/2005 -- 12/25/2018

Settlement Dates: 1/2/2019 -- 1/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-36.817	-$1,137.41	$720.54	-$416.87
	Total:	**-36.817**	**-$1,137.41**	**$720.54**	**-$416.87**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.264	$7.35	-$6.39	$0.96
	Total:	**0.264**	**$7.35**	**-$6.39**	**$0.96**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.417	$11.76	-$10.39	$1.37
	Total:	**0.417**	**$11.76**	**-$10.39**	**$1.37**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	7.584	$175.89	-$3,755.91	-$3,580.02
	Total:	**7.584**	**$175.89**	**-$3,755.91**	**-$3,580.02**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.155	-$3.26	$81.90	$78.64
	Total:	**-0.155**	**-$3.26**	**$81.90**	**$78.64**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-28.707**	**-$945.67**	**-$2,970.25**	**-$3,915.92**
Margins	**Total**	**-28.707**	**-$945.67**	**-$2,970.25**	**-$3,915.92**

Marketing Book Costs - Monthly February 2019

Operating Dates: 1/24/2019 -- 2/20/2019

Settlement Dates: 1/31/2019 -- 2/27/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1.047	$51.37	-$21.32	$30.05
	Real Time	4,965.538	$101,924.83	-$104,750.95	-$2,826.12
	Total:	**4,966.585**	**$101,976.20**	**-$104,772.27**	**-$2,796.07**
OTP.COYOT1	Day Ahead	39.926	$907.52	-$436.79	$470.73
	Real Time	1,426.354	$40,362.15	-$15,826.00	$24,536.15
	Total:	**1,466.280**	**$41,269.67**	**-$16,262.79**	**$25,006.88**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	196.662	$20,499.31	-$86,976.27	-$66,476.96
	Total:	**196.662**	**$20,499.31**	**-$86,976.27**	**-$66,476.96**
OTP.HOOTL2	Day Ahead	53.891	$1,916.78	-$1,310.13	$606.65
	Real Time	699.367	$18,528.59	-$17,151.74	$1,376.85
	Total:	**753.258**	**$20,445.37**	**-$18,461.87**	**$1,983.50**
OTP.HOOTL3	Day Ahead	32.405	$1,110.87	-$797.49	$313.38
	Real Time	2,271.196	$230,241.55	-$56,070.72	$174,170.83
	Total:	**2,303.601**	**$231,352.42**	**-$56,868.21**	**$174,484.21**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	197.733	$20,779.44	-$101,535.09	-$80,755.65
	Total:	**197.733**	**$20,779.44**	**-$101,535.09**	**-$80,755.65**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	194.657	$20,641.50	-$104,391.78	-$83,750.28
	Total:	**194.657**	**$20,641.50**	**-$104,391.78**	**-$83,750.28**
OTP.SLWAYO1	Day Ahead	10.965	$1,012.84	-$809.55	$203.29
	Real Time	895.134	$27,811.80	-$47,621.39	-$19,809.59
	Total:	**906.099**	**$28,824.64**	**-$48,430.94**	**-$19,606.30**
Day Ahead	**Total**	**138.234**	**$4,999.38**	**-$3,375.28**	**$1,624.10**
Real Time	**Total**	**10,846.641**	**$480,789.17**	**-$534,323.94**	**-$53,534.77**
Margins	**Total**	**10,984.875**	**$485,788.55**	**-$537,699.22**	**-$51,910.67**

Marketing Book Costs - Monthly March 2019

Operating Dates: 2/21/2019 -- 3/21/2019

Settlement Dates: 2/28/2019 -- 3/28/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,552.891	$37,891.46	-$28,877.34	$9,014.12
	Real Time	3,362.791	$64,237.80	-$65,045.95	-$808.15
	Total:	**4,915.682**	**$102,129.26**	**-$93,923.29**	**$8,205.97**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	4,310.704	$102,942.60	-$48,425.64	$54,516.96
	Total:	**4,310.704**	**$102,942.60**	**-$48,425.64**	**$54,516.96**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	5.105	$154.06	-$2,159.01	-$2,004.95
	Total:	**5.105**	**$154.06**	**-$2,159.01**	**-$2,004.95**
OTP.HOOTL2	Day Ahead	904.990	$26,841.52	-$22,081.44	$4,760.08
	Real Time	195.305	$11,785.03	-$4,786.91	$6,998.12
	Total:	**1,100.295**	**$38,626.55**	**-$26,868.35**	**$11,758.20**
OTP.HOOTL3	Day Ahead	2,000.632	$65,963.51	-$49,241.35	$16,722.16
	Real Time	632.759	$28,460.96	-$15,942.97	$12,517.99
	Total:	**2,633.391**	**$94,424.47**	**-$65,184.32**	**$29,240.15**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	7.679	$166.78	-$3,506.44	-$3,339.66
	Total:	**7.679**	**$166.78**	**-$3,506.44**	**-$3,339.66**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.805	$16.07	-$377.47	-$361.40
	Total:	**0.805**	**$16.07**	**-$377.47**	**-$361.40**
OTP.SLWAYO1	Day Ahead	523.613	$23,240.68	-$16,454.11	$6,786.57
	Real Time	1,725.273	$58,095.05	-$60,990.10	-$2,895.05
	Total:	**2,248.886**	**$81,335.73**	**-$77,444.21**	**$3,891.52**
Day Ahead	**Total**	**4,982.126**	**$153,937.17**	**-$116,654.24**	**$37,282.93**
Real Time	**Total**	**10,240.421**	**$265,858.35**	**-$201,234.49**	**$64,623.86**
Margins	**Total**	**15,222.547**	**$419,795.52**	**-$317,888.73**	**$101,906.79**

Marketing Book Costs - Monthly Adjustments   March 2019

Operating Dates: 4/1/2005 -- 2/20/2019

Settlement Dates: 2/28/2019 -- 3/28/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.034	-$0.68	$0.41	-$0.27
	Total:	**-0.034**	**-$0.68**	**$0.41**	**-$0.27**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-0.034**	**-$0.68**	**$0.41**	**-$0.27**
Margins	**Total**	**-0.034**	**-$0.68**	**$0.41**	**-$0.27**

Marketing Book Costs - Monthly April 2019

Operating Dates: 3/22/2019 -- 4/22/2019

Settlement Dates: 3/29/2019 -- 4/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	2,349.567	$49,081.06	-$43,630.57	$5,450.49
	Real Time	5,639.669	$106,861.99	-$106,019.36	$842.63
	Total:	**7,989.236**	**$155,943.05**	**-$149,649.93**	**$6,293.12**
OTP.COYOT1	Day Ahead	4.195	$91.53	-$47.86	$43.67
	Real Time	143.197	$2,804.99	-$1,789.83	$1,015.16
	Total:	**147.392**	**$2,896.52**	**-$1,837.69**	**$1,058.83**
OTP.HOOTL2	Day Ahead	399.174	$10,603.49	-$10,078.94	$524.55
	Real Time	498.650	$10,874.32	-$12,602.86	-$1,728.54
	Total:	**897.824**	**$21,477.81**	**-$22,681.80**	**-$1,203.99**
OTP.HOOTL3	Day Ahead	546.375	$15,493.17	-$13,572.95	$1,920.22
	Real Time	580.607	$13,631.25	-$14,725.58	-$1,094.33
	Total:	**1,126.982**	**$29,124.42**	**-$28,298.53**	**$825.89**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	22.189	$462.05	-$8,764.08	-$8,302.03
	Total:	**22.189**	**$462.05**	**-$8,764.08**	**-$8,302.03**
OTP.SLWAYO1	Day Ahead	500.058	$18,478.31	-$13,333.04	$5,145.27
	Real Time	1,080.619	$28,767.78	-$32,407.25	-$3,639.47
	Total:	**1,580.677**	**$47,246.09**	**-$45,740.29**	**$1,505.80**
Day Ahead	**Total**	**3,799.369**	**$93,747.56**	**-$80,663.36**	**$13,084.20**
Real Time	**Total**	**7,964.931**	**$163,402.38**	**-$176,308.96**	**-$12,906.58**
Margins	**Total**	**11,764.300**	**$257,149.94**	**-$256,972.32**	**$177.62**

Marketing Book Costs - Monthly Adjustments April 2019

Operating Dates: 4/1/2005 -- 3/21/2019

Settlement Dates: 3/29/2019 -- 4/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.787	$12.20	-$15.99	-$3.79
	Total:	**0.787**	**$12.20**	**-$15.99**	**-$3.79**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.583	-$13.22	$6.78	-$6.44
	Total:	**-0.583**	**-$13.22**	**$6.78**	**-$6.44**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.232	$4.61	-$5.67	-$1.06
	Total:	**0.232**	**$4.61**	**-$5.67**	**-$1.06**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.287	$5.79	-$7.21	-$1.42
	Total:	**0.287**	**$5.79**	**-$7.21**	**-$1.42**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.003	-$0.02	-$0.14	-$0.16
	Total:	**0.003**	**-$0.02**	**-$0.14**	**-$0.16**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.726**	**$9.36**	**-$22.23**	**-$12.87**
Margins	**Total**	**0.726**	**$9.36**	**-$22.23**	**-$12.87**

Marketing Book Costs - Monthly May 2019

Operating Dates: 4/23/2019 -- 5/23/2019

Settlement Dates: 4/30/2019 -- 5/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	2,190.868	$51,327.60	-$40,947.44	$10,380.16
	Real Time	6,253.634	$117,451.63	-$121,863.11	-$4,411.48
	Total:	**8,444.502**	**$168,779.23**	**-$162,810.55**	**$5,968.68**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	12.614	$292.42	-$5,337.29	-$5,044.87
	Total:	**12.614**	**$292.42**	**-$5,337.29**	**-$5,044.87**
OTP.HOOTL2	Day Ahead	282.000	$8,170.76	-$6,901.32	$1,269.44
	Real Time	857.866	$22,579.92	-$21,080.51	$1,499.41
	Total:	**1,139.866**	**$30,750.68**	**-$27,981.83**	**$2,768.85**
OTP.HOOTL3	Day Ahead	757.163	$22,025.18	-$18,636.68	$3,388.50
	Real Time	397.156	$9,885.86	-$9,844.92	$40.94
	Total:	**1,154.319**	**$31,911.04**	**-$28,481.60**	**$3,429.44**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	14.853	$485.02	-$6,351.05	-$5,866.03
	Total:	**14.853**	**$485.02**	**-$6,351.05**	**-$5,866.03**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	15.328	$197.07	-$580.93	-$383.86
	Total:	**15.328**	**$197.07**	**-$580.93**	**-$383.86**
Day Ahead	**Total**	**3,230.031**	**$81,523.54**	**-$66,485.44**	**$15,038.10**
Real Time	**Total**	**7,551.451**	**$150,891.92**	**-$165,057.81**	**-$14,165.89**
Margins	**Total**	**10,781.482**	**$232,415.46**	**-$231,543.25**	**$872.21**

Marketing Book Costs - Monthly Adjustments May 2019

Operating Dates: 4/1/2005 -- 4/22/2019

Settlement Dates: 4/30/2019 -- 5/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	4.311	$118.73	-$85.88	$32.85
	Total:	**4.311**	**$118.73**	**-$85.88**	**$32.85**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.412	$88.77	-$39.16	$49.61
	Total:	**3.412**	**$88.77**	**-$39.16**	**$49.61**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.583	$39.32	-$39.04	$0.28
	Total:	**1.583**	**$39.32**	**-$39.04**	**$0.28**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.441	$58.76	-$62.13	-$3.37
	Total:	**2.441**	**$58.76**	**-$62.13**	**-$3.37**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.716	$15.33	-$29.83	-$14.50
	Total:	**0.716**	**$15.33**	**-$29.83**	**-$14.50**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**12.463**	**$320.91**	**-$256.04**	**$64.87**
Margins	**Total**	**12.463**	**$320.91**	**-$256.04**	**$64.87**

Marketing Book Costs - Monthly June 2019

Operating Dates: 5/24/2019 -- 6/20/2019

Settlement Dates: 5/31/2019 -- 6/27/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	4.450	$88.42	-$87.18	$1.24
	Real Time	18,550.671	$343,549.03	-$375,348.08	-$31,799.05
	Total:	**18,555.121**	**$343,637.45**	**-$375,435.26**	**-$31,797.81**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.414	$19.25	-$17.85	$1.40
	Total:	**1.414**	**$19.25**	**-$17.85**	**$1.40**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.708	$42.70	-$1,181.61	-$1,138.91
	Total:	**2.708**	**$42.70**	**-$1,181.61**	**-$1,138.91**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	897.780	$29,615.95	-$22,427.14	$7,188.81
	Total:	**897.780**	**$29,615.95**	**-$22,427.14**	**$7,188.81**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.407	$21.29	-$669.22	-$647.93
	Total:	**1.407**	**$21.29**	**-$669.22**	**-$647.93**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.309	$19.76	-$649.15	-$629.39
	Total:	**1.309**	**$19.76**	**-$649.15**	**-$629.39**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	587.665	$18,428.87	-$16,807.36	$1,621.51
	Total:	**587.665**	**$18,428.87**	**-$16,807.36**	**$1,621.51**
Day Ahead	**Total**	**4.450**	**$88.42**	**-$87.18**	**$1.24**
Real Time	**Total**	**20,042.954**	**$391,696.85**	**-$417,100.41**	**-$25,403.56**
Margins	**Total**	**20,047.404**	**$391,785.27**	**-$417,187.59**	**-$25,402.32**

Marketing Book Costs - Monthly July 2019

Operating Dates: 6/21/2019 -- 7/23/2019

Settlement Dates: 6/28/2019 -- 7/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	12,882.743	$259,922.89	-$280,135.36	-$20,212.47
	Total:	**12,882.743**	**$259,922.89**	**-$280,135.36**	**-$20,212.47**
OTP.COYOT1	Day Ahead	10.267	$159.65	-$118.69	$40.96
	Real Time	4,878.666	$102,797.06	-$56,914.08	$45,882.98
	Total:	**4,888.933**	**$102,956.71**	**-$57,032.77**	**$45,923.94**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3,857.163	$138,254.96	-$96,385.00	$41,869.96
	Total:	**3,857.163**	**$138,254.96**	**-$96,385.00**	**$41,869.96**
OTP.SLWAYO1	Day Ahead	99.209	$4,318.48	-$2,528.45	$1,790.03
	Real Time	877.797	$28,894.44	-$24,451.92	$4,442.52
	Total:	**977.006**	**$33,212.92**	**-$26,980.37**	**$6,232.55**
Day Ahead	**Total**	**109.476**	**$4,478.13**	**-$2,647.14**	**$1,830.99**
Real Time	**Total**	**22,496.369**	**$529,869.35**	**-$457,886.36**	**$71,982.99**
Margins	**Total**	**22,605.845**	**$534,347.48**	**-$460,533.50**	**$73,813.98**

Marketing Book Costs - Monthly Adjustments July 2019

Operating Dates: 4/1/2005 -- 6/20/2019

Settlement Dates: 6/28/2019 -- 7/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.774	$18.90	-$40.05	-$21.15
	Total:	**1.774**	**$18.90**	**-$40.05**	**-$21.15**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	6.475	$176.38	-$2,824.98	-$2,648.60
	Total:	**6.475**	**$176.38**	**-$2,824.98**	**-$2,648.60**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**8.249**	**$195.28**	**-$2,865.03**	**-$2,669.75**
Margins	**Total**	**8.249**	**$195.28**	**-$2,865.03**	**-$2,669.75**

Marketing Book Costs - Monthly August 2019

Operating Dates: 7/24/2019 -- 8/22/2019

Settlement Dates: 7/31/2019 -- 8/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	1,031.897	$26,735.84	-$22,651.31	$4,084.53
	Real Time	8,662.122	$166,783.85	-$200,061.55	-$33,277.70
	Total:	**9,694.019**	**$193,519.69**	**-$222,712.86**	**-$29,193.17**
OTP.COYOT1	Day Ahead	227.385	$2,855.71	-$2,595.36	$260.35
	Real Time	7,417.545	$124,478.88	-$85,993.87	$38,485.01
	Total:	**7,644.930**	**$127,334.59**	**-$88,589.23**	**$38,745.36**
OTP.HETLA	Day Ahead	11.340	$330.02	-$4,947.53	-$4,617.51
	Real Time	29.829	$642.01	-$8,334.89	-$7,692.88
	Total:	**41.169**	**$972.03**	**-$13,282.42**	**-$12,310.39**
OTP.HOOTL2	Day Ahead	453.941	$14,599.17	-$11,098.85	$3,500.32
	Real Time	1,000.367	$30,371.44	-$24,826.36	$5,545.08
	Total:	**1,454.308**	**$44,970.61**	**-$35,925.21**	**$9,045.40**
OTP.HOOTL3	Day Ahead	1,283.194	$43,271.23	-$31,928.93	$11,342.30
	Real Time	-32.346	$318.43	$734.12	$1,052.55
	Total:	**1,250.848**	**$43,589.66**	**-$31,194.81**	**$12,394.85**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	45.362	$1,050.69	-$15,261.74	-$14,211.05
	Total:	**45.362**	**$1,050.69**	**-$15,261.74**	**-$14,211.05**
OTP.JAMSPK2	Day Ahead	24.000	$687.60	-$10,131.12	-$9,443.52
	Real Time	29.560	$555.45	-$9,075.04	-$8,519.59
	Total:	**53.560**	**$1,243.05**	**-$19,206.16**	**-$17,963.11**
OTP.SLWAYO1	Day Ahead	2,459.483	$86,386.87	-$56,219.76	$30,167.11
	Real Time	-69.728	$2,357.91	$2,200.04	$4,557.95
	Total:	**2,389.755**	**$88,744.78**	**-$54,019.72**	**$34,725.06**
Day Ahead	**Total**	**5,491.240**	**$174,866.44**	**-$139,572.86**	**$35,293.58**
Real Time	**Total**	**17,082.711**	**$326,558.66**	**-$340,619.29**	**-$14,060.63**
Margins	**Total**	**22,573.951**	**$501,425.10**	**-$480,192.15**	**$21,232.95**

Marketing Book Costs - Monthly Adjustments August 2019

Operating Dates: 4/1/2005 -- 7/23/2019

Settlement Dates: 7/31/2019 -- 8/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.817	$71.67	-$84.19	-$12.52
	Total:	**3.817**	**$71.67**	**-$84.19**	**-$12.52**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-1.375	-$18.56	$17.42	-$1.14
	Total:	**-1.375**	**-$18.56**	**$17.42**	**-$1.14**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	4.189	$56.82	-$1,827.53	-$1,770.71
	Total:	**4.189**	**$56.82**	**-$1,827.53**	**-$1,770.71**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-1.407	-$21.29	$669.22	$647.93
	Total:	**-1.407**	**-$21.29**	**$669.22**	**$647.93**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.524	-$8.72	$259.86	$251.14
	Total:	**-0.524**	**-$8.72**	**$259.86**	**$251.14**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**4.700**	**$79.92**	**-$965.22**	**-$885.30**
Margins	**Total**	**4.700**	**$79.92**	**-$965.22**	**-$885.30**

Marketing Book Costs - Monthly September 2019

Operating Dates: 8/23/2019 -- 9/22/2019

Settlement Dates: 8/30/2019 -- 9/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	4,584.349	$97,287.75	-$81,407.17	$15,880.58
	Real Time	9,969.495	$178,530.92	-$192,230.23	-$13,699.31
	Total:	**14,553.844**	**$275,818.67**	**-$273,637.40**	**$2,181.27**
OTP.COYOT1	Day Ahead	240.087	$3,246.37	-$4,031.94	-$785.57
	Real Time	8,821.524	$143,434.19	-$106,106.28	$37,327.91
	Total:	**9,061.611**	**$146,680.56**	**-$110,138.22**	**$36,542.34**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	29.072	$386.74	-$732.90	-$346.16
	Total:	**29.072**	**$386.74**	**-$732.90**	**-$346.16**
OTP.HOOTL3	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	7.226	$97.05	-$184.05	-$87.00
	Total:	**7.226**	**$97.05**	**-$184.05**	**-$87.00**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.238	$3.55	-$113.20	-$109.65
	Total:	**0.238**	**$3.55**	**-$113.20**	**-$109.65**
OTP.SLWAYO1	Day Ahead	1,591.328	$57,626.47	-$40,964.45	$16,662.02
	Real Time	764.501	$34,075.13	-$17,814.01	$16,261.12
	Total:	**2,355.829**	**$91,701.60**	**-$58,778.46**	**$32,923.14**
Day Ahead	**Total**	**6,415.764**	**$158,160.59**	**-$126,403.56**	**$31,757.03**
Real Time	**Total**	**19,592.056**	**$356,527.58**	**-$317,180.67**	**$39,346.91**
Margins	**Total**	**26,007.820**	**$514,688.17**	**-$443,584.23**	**$71,103.94**

Marketing Book Costs - Monthly Adjustments September 2019

Operating Dates: 4/1/2005 -- 8/22/2019

Settlement Dates: 8/30/2019 -- 9/29/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.038	-$0.63	$0.88	$0.25
	Total:	**-0.038**	**-$0.63**	**$0.88**	**$0.25**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.049	-$0.85	$0.56	-$0.29
	Total:	**-0.049**	**-$0.85**	**$0.56**	**-$0.29**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.300	-$3.15	$130.93	$127.78
	Total:	**-0.300**	**-$3.15**	**$130.93**	**$127.78**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.091	-$1.42	$31.71	$30.29
	Total:	**-0.091**	**-$1.42**	**$31.71**	**$30.29**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.785	-$11.04	$389.29	$378.25
	Total:	**-0.785**	**-$11.04**	**$389.29**	**$378.25**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.054	-$1.28	$1.39	$0.11
	Total:	**-0.054**	**-$1.28**	**$1.39**	**$0.11**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-1.317**	**-$18.37**	**$554.76**	**$536.39**
Margins	**Total**	**-1.317**	**-$18.37**	**$554.76**	**$536.39**

Marketing Book Costs - Monthly October 2019

Operating Dates: 9/23/2019 -- 10/23/2019

Settlement Dates: 9/30/2019 -- 10/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	2,603.807	$49,483.12	-$45,955.81	$3,527.31
	Real Time	3,580.654	$35,608.66	-$64,194.86	-$28,586.20
	Total:	**6,184.461**	**$85,091.78**	**-$110,150.67**	**-$25,058.89**
OTP.COYOT1	Day Ahead	46.229	$754.98	-$544.57	$210.41
	Real Time	2,020.725	$25,538.45	-$24,128.43	$1,410.02
	Total:	**2,066.954**	**$26,293.43**	**-$24,673.00**	**$1,620.43**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.470	$2.00	-$188.46	-$186.46
	Total:	**0.470**	**$2.00**	**-$188.46**	**-$186.46**
OTP.HOOTL2	Day Ahead	182.185	$5,726.43	-$4,454.65	$1,271.78
	Real Time	87.070	$78.32	-$2,232.76	-$2,154.44
	Total:	**269.255**	**$5,804.75**	**-$6,687.41**	**-$882.66**
OTP.HOOTL3	Day Ahead	269.186	$9,486.84	-$6,698.25	$2,788.59
	Real Time	-208.547	-$3,827.70	$5,302.95	$1,475.25
	Total:	**60.639**	**$5,659.14**	**-$1,395.30**	**$4,263.84**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	1.241	$20.32	-$515.39	-$495.07
	Total:	**1.241**	**$20.32**	**-$515.39**	**-$495.07**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	2.004	$13.12	-$941.03	-$927.91
	Total:	**2.004**	**$13.12**	**-$941.03**	**-$927.91**
OTP.SLWAYO1	Day Ahead	1,270.921	$30,705.98	-$29,196.94	$1,509.04
	Real Time	103.523	$3,699.23	-$1,358.89	$2,340.34
	Total:	**1,374.444**	**$34,405.21**	**-$30,555.83**	**$3,849.38**
Day Ahead	**Total**	**4,372.328**	**$96,157.35**	**-$86,850.22**	**$9,307.13**
Real Time	**Total**	**5,587.140**	**$61,132.40**	**-$88,256.87**	**-$27,124.47**
Margins	**Total**	**9,959.468**	**$157,289.75**	**-$175,107.09**	**-$17,817.34**

Marketing Book Costs - Monthly Adjustments October 2019

Operating Dates: 4/1/2005 -- 9/22/2019

Settlement Dates: 9/30/2019 -- 10/30/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.134	$2.25	-$2.63	-$0.38
	Total:	**0.134**	**$2.25**	**-$2.63**	**-$0.38**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.497	-$9.60	$188.89	$179.29
	Total:	**-0.497**	**-$9.60**	**$188.89**	**$179.29**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.272	-$4.96	$88.73	$83.77
	Total:	**-0.272**	**-$4.96**	**$88.73**	**$83.77**
OTP.SLWAYO1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-0.007	-$0.14	$0.23	$0.09
	Total:	**-0.007**	**-$0.14**	**$0.23**	**$0.09**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**-0.642**	**-$12.45**	**$275.22**	**$262.77**
Margins	**Total**	**-0.642**	**-$12.45**	**$275.22**	**$262.77**

Marketing Book Costs - Monthly November 2019

Operating Dates: 10/24/2019 -- 11/21/2019

Settlement Dates: 10/31/2019 -- 11/28/2019

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	490.392	$9,139.99	-$8,337.94	$802.05
	Real Time	8,848.475	$173,329.79	-$152,422.89	$20,906.90
	Total:	**9,338.867**	**$182,469.78**	**-$160,760.83**	**$21,708.95**
OTP.COYOT1	Day Ahead	101.851	$1,716.04	-$1,206.14	$509.90
	Real Time	3,002.249	$61,015.75	-$36,561.71	$24,454.04
	Total:	**3,104.100**	**$62,731.79**	**-$37,767.85**	**$24,963.94**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	0.017	$0.34	-$7.46	-$7.12
	Total:	**0.017**	**$0.34**	**-$7.46**	**-$7.12**
OTP.HOOTL2	Day Ahead	46.297	$1,180.40	-$1,125.56	$54.84
	Real Time	315.217	$6,969.63	-$7,807.81	-$838.18
	Total:	**361.514**	**$8,150.03**	**-$8,933.37**	**-$783.34**
OTP.HOOTL3	Day Ahead	66.590	$1,889.91	-$1,648.23	$241.68
	Real Time	189.840	$4,283.09	-$4,766.73	-$483.64
	Total:	**256.430**	**$6,173.00**	**-$6,414.96**	**-$241.96**
OTP.SLWAYO1	Day Ahead	211.062	$7,399.32	-$5,849.28	$1,550.04
	Real Time	1,821.595	$76,378.41	-$53,690.13	$22,688.28
	Total:	**2,032.657**	**$83,777.73**	**-$59,539.41**	**$24,238.32**
Day Ahead	**Total**	**916.192**	**$21,325.66**	**-$18,167.15**	**$3,158.51**
Real Time	**Total**	**14,177.393**	**$321,977.01**	**-$255,256.73**	**$66,720.28**
Margins	**Total**	**15,093.585**	**$343,302.67**	**-$273,423.88**	**$69,878.79**

Marketing Book Costs - Monthly December 2019

Operating Dates: 11/22/2019 -- 12/25/2019

Settlement Dates: 11/29/2019 -- 1/1/2020

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	122.279	$2,633.51	-$2,057.10	$576.41
	Real Time	10,743.362	$180,051.58	-$203,461.63	-$23,410.05
	Total:	**10,865.641**	**$182,685.09**	**-$205,518.73**	**-$22,833.64**
OTP.COYOT1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	5,460.810	$92,545.46	-$68,744.85	$23,800.61
	Total:	**5,460.810**	**$92,545.46**	**-$68,744.85**	**$23,800.61**
OTP.HETLA	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	20.751	$493.66	-$8,119.36	-$7,625.70
	Total:	**20.751**	**$493.66**	**-$8,119.36**	**-$7,625.70**
OTP.HOOTL2	Day Ahead	10.841	$303.05	-$263.00	$40.05
	Real Time	151.098	$3,532.36	-$3,704.17	-$171.81
	Total:	**161.939**	**$3,835.41**	**-$3,967.17**	**-$131.76**
OTP.HOOTL3	Day Ahead	18.277	$492.02	-$449.80	$42.22
	Real Time	1,593.635	$25,483.96	-$40,060.23	-$14,576.27
	Total:	**1,611.912**	**$25,975.98**	**-$40,510.03**	**-$14,534.05**
OTP.JAMSPK1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.173	$52.98	-$1,288.38	-$1,235.40
	Total:	**3.173**	**$52.98**	**-$1,288.38**	**-$1,235.40**
OTP.JAMSPK2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	25.069	$504.60	-$10,596.57	-$10,091.97
	Total:	**25.069**	**$504.60**	**-$10,596.57**	**-$10,091.97**
OTP.SLWAYO1	Day Ahead	137.415	$4,866.97	-$3,716.33	$1,150.64
	Real Time	680.350	$16,988.21	-$20,072.90	-$3,084.69
	Total:	**817.765**	**$21,855.18**	**-$23,789.23**	**-$1,934.05**
Day Ahead	**Total**	**288.812**	**$8,295.55**	**-$6,486.23**	**$1,809.32**
Real Time	**Total**	**18,678.248**	**$319,652.81**	**-$356,048.09**	**-$36,395.28**
Margins	**Total**	**18,967.060**	**$327,948.36**	**-$362,534.32**	**-$34,585.96**

Marketing Book Costs - Monthly Adjustments December 2019

Operating Dates: 4/1/2005 -- 11/21/2019

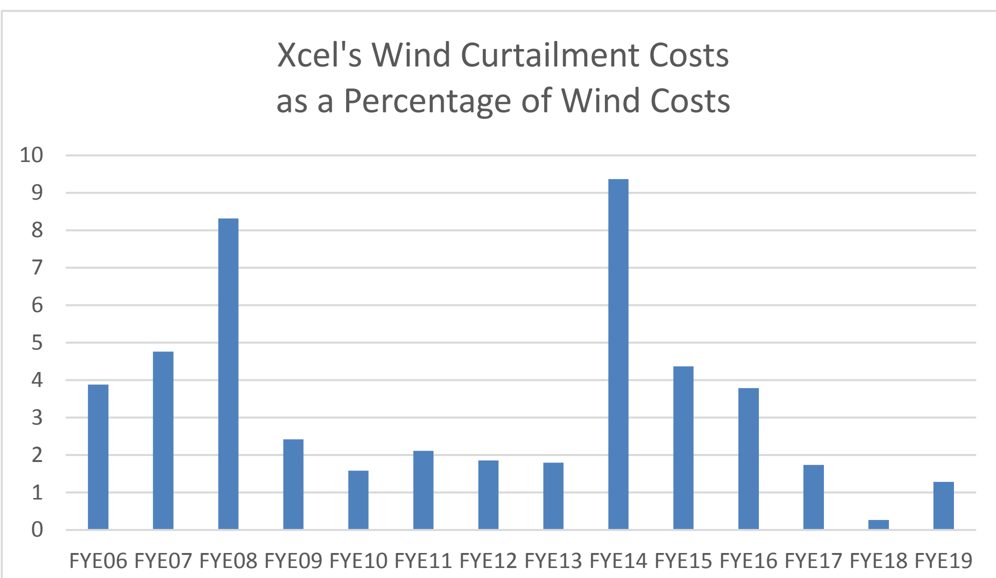
Settlement Dates: 11/29/2019 -- 1/1/2020

Asset	DA/RT	MWH	Revenue	Fuel	Profit
OTP.BIGSTON1	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	3.150	$55.44	-$52.98	$2.46
	Total:	**3.150**	**$55.44**	**-$52.98**	**$2.46**
OTP.HOOTL2	Day Ahead	0.000	$0.00	$0.00	$0.00
	Real Time	-2.664	-$51.31	$66.52	$15.21
	Total:	**-2.664**	**-$51.31**	**$66.52**	**$15.21**
Day Ahead	**Total**	**0.000**	**$0.00**	**$0.00**	**$0.00**
Real Time	**Total**	**0.486**	**$4.13**	**$13.54**	**$17.67**
Margins	**Total**	**0.486**	**$4.13**	**$13.54**	**$17.67**

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
FYE18	0.27
FYE19	1.28
Min	0.27
Max	9.37

Source:
Xcel's monthly FCA input data emails.



Docket No. E999/AA-20-171
Department Attachment B2
(Outages) Page 1 of 1

	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%
FYE18	2.54%	0.00%	0.67%
FYE19	3.25%	2.17%	2.92%

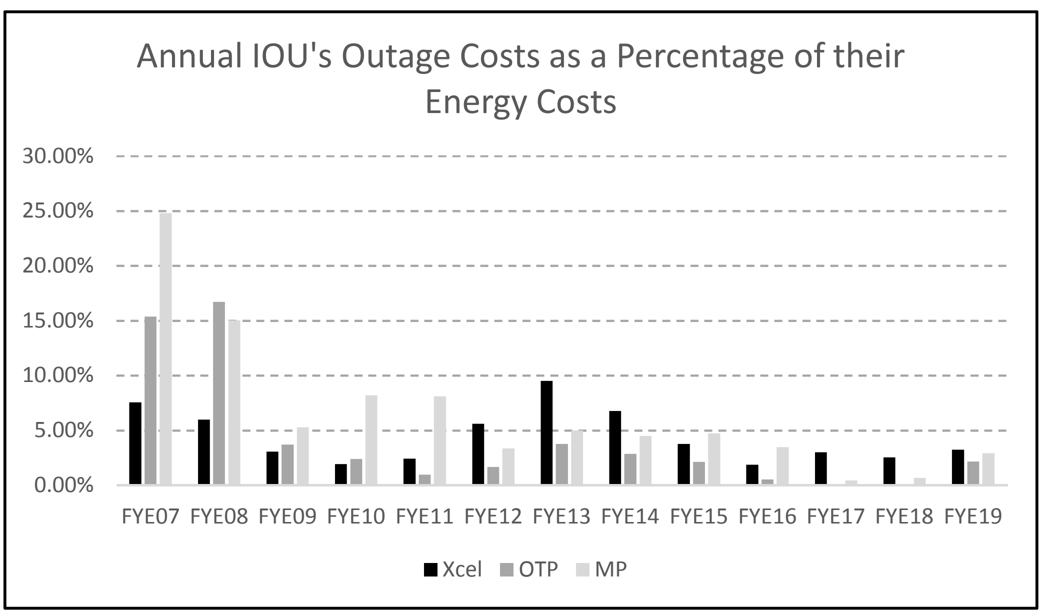
FYE07-FYE17 Summary

	Xcel	OTP	MP
Min	1.88%	0.00%	0.45%
Avg	4.40%	4.02%	6.65%
Max	9.50%	16.70%	24.80%

FYE09-FYE17 Summary

	Xcel	OTP	MP
Min	1.88%	0.00%	0.45%
Avg	4.21%	2.00%	4.79%
Max	9.50%	3.77%	8.20%

Source: IOU's monthly FCA input data emails.



Maintenance Expenses of Generation Plants

Actual Maintenance Expense

	2014	2015	2016	2017	2018	2019	2018-2019 Average
Xcel	207,105,781	199,893,337	187,845,248	160,546,634	173,416,699	161,116,736	167,266,718
OTP	16,587,034	14,646,839	13,573,426	12,540,306	15,365,941	15,589,236	15,477,589
MP	42,236,247	40,475,462	38,505,407	38,555,947	36,050,836	31,780,712	36,050,836

MP's data includes wind maintenance expenses when compared to previous DOC reported 2014-2016 data.
MP's 2019 Maintenance Expense is projected, not actuals.

	Most Recent Rate Case	Test Year	Test Year Budgeted Maintenance Expense	2018-2019 Avg. Actual Maintenance Expense	Difference: Actual less Budgeted	Percentage Difference
Xcel	GR-15-826	2016	$ 184,709,427	$ 167,266,718	$ (17,442,710)	-9.4%
OTP	GR-15-1033	2016	$ 15,099,063	$ 15,477,589	$ 378,526	2.5%
MP	GR-19-442	2020	$ 36,093,940	$ 36,050,836	$ (43,104)	-0.1%

MP	kWh Retail & Firm Resale (a)	FCA Retail Sales (b)	System Costs (c)
Jul-18	828,747,440	696,463,050	$21,011,668
Aug-18	828,571,242	697,917,065	$21,049,153
Sep-18	802,447,610	682,061,581	$19,345,602
Oct-18	814,036,958	687,757,241	$19,430,465
Nov-18	831,932,275	698,853,196	$20,404,016
Dec-18	865,766,876	729,863,881	$19,797,666
Jan-19	902,502,666	754,792,751	$21,878,419
Feb-19	837,028,933	705,799,281	$21,937,250
Mar-19	865,495,469	733,658,813	$22,050,963
Apr-19	806,555,485	687,841,695	$17,320,569
May-19	789,239,969	672,922,052	$15,687,190
Jun-19	773,769,611	656,300,528	$18,585,010
Jul-19	799,020,123	680,449,027	$24,418,563
Aug-19	812,547,511	699,818,104	$18,750,883
Sep-19	772,121,750	667,687,441	$15,867,434
Oct-19	784,639,739	673,525,487	$15,037,742
Nov-19	813,424,149	697,023,002	$18,143,547
Dec-19	821,719,157	694,165,956	$17,218,492
Total	14,749,566,963	12,516,900,151	$ 347,934,632

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

Minnesota base cost ($/kWh): July 18 - December 19 0.01018 0.02121

MP	FCA Recovery (d)	Old FCA # 17 Recovery (e)	Old FCA # 18 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-18	8,261,914	$ -	-	$ 7,080,011	$ 15,341,926	$ 17,655,338	$ (2,313,412)	0.022	0.025
Aug-18	8,832,138	$ -	-	$ 7,104,922	$ 15,937,060	$ 17,727,093	$ (1,790,034)	0.023	0.025
Sep-18	9,709,419	$ -	-	$ 6,940,024	$ 16,649,443	$ 16,444,505	$ 204,939	0.024	0.024
Oct-18	10,431,526	$ -	-	$ 6,984,924	$ 17,416,450	$ 16,416,765	$ 999,685	0.025	0.024
Nov-18	10,183,493	$ -	-	$ 7,105,529	$ 17,289,022	$ 17,142,869	$ 146,153	0.025	0.025
Dec-18	2,027,474	$ -	-	$ 15,473,909	$ 17,501,383	$ 16,691,987	$ 809,396	0.024	0.023
Jan-19	2,255,722	$ -	-	$ 16,002,210	$ 18,257,932	$ 18,296,176	$ (38,244)	0.024	0.024
Feb-19	1,746,128	$ -	-	$ 14,986,500	$ 16,732,628	$ 18,498,999	$ (1,766,371)	0.024	0.026
Mar-19	1,731,658	$ -	-	$ 15,557,395	$ 17,289,053	$ 18,693,627	$ (1,404,574)	0.024	0.025
Apr-19	2,736,642	$ -	-	$ 14,583,416	$ 17,320,058	$ 14,767,961	$ 2,552,097	0.025	0.021
May-19	3,111,062	$ -	-	$ 14,257,485	$ 17,368,547	$ 13,377,690	$ 3,990,857	0.026	0.020
Jun-19	1,534,667	$ -	-	$ 13,904,022	$ 15,438,689	$ 15,764,339	$ (325,650)	0.024	0.024
Jul-19	(356,598)	$ -	-	$ 14,418,862	$ 14,062,264	$ 20,794,522	$ (6,732,258)	0.021	0.031
Aug-19	501,329	$ -	-	$ 14,839,546	$ 15,340,875	$ 16,151,802	$ (810,927)	0.022	0.023
Sep-19	4,090,091	$ -	-	$ 14,149,646	$ 18,239,737	$ 13,720,977	$ 4,518,760	0.027	0.021
Oct-19	3,750,229	$ -	-	$ 14,266,209	$ 18,016,439	$ 12,911,484	$ 5,104,955	0.027	0.019
Nov-19	442,434	$ -	-	$ 14,769,806	$ 15,212,240	$ 15,550,583	$ (338,343)	0.022	0.022
Dec-19	(940,931)	$ -	-	$ 14,721,183	$ 13,780,252	$ 14,542,777	$ (762,525)	0.020	0.021
Total	$ 70,048,399	$ -	$ -	$ 227,145,598	$ 297,193,997	$ 295,149,495	$ 2,044,502	0.024	0.0236

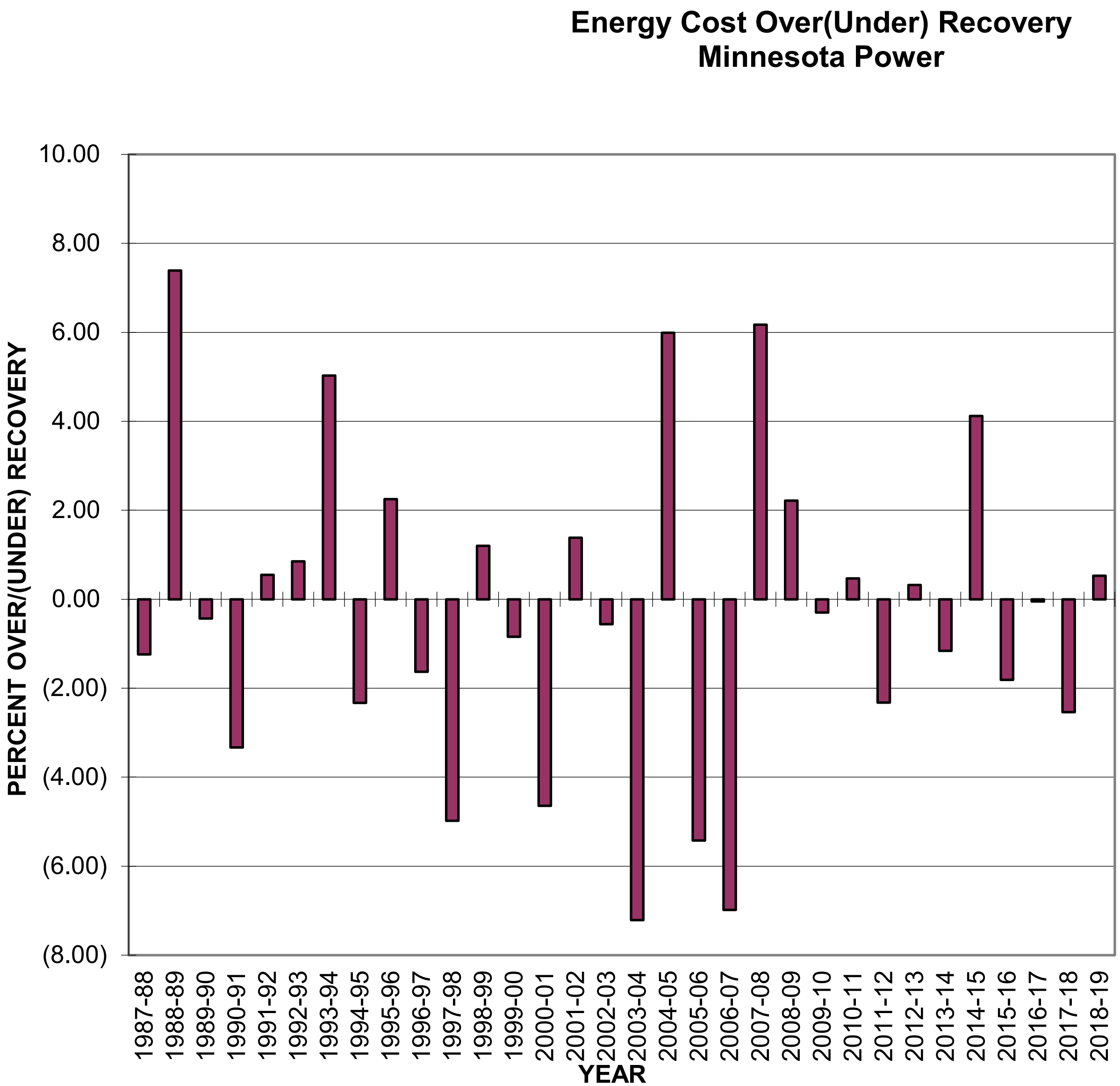
Source (d-g): Department's calculations based on data provided in MP's monthly FCAs.
(h) = SUM(d:g)
(i)=(b)*(c)/(a)
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Total Company Recovery, July 2018 - June 2019, By Month

Month	**Minnesota Energy Costs**	**Minnesota Recovery**	**Over(Under) Recovery**	**Over(Under) Percentage**
	(a)	(b)	(c)	(d)
July	$ 17,655,338	$15,341,926	($2,313,412)	(13.10%)
August	$ 17,727,093	$15,937,060	($1,790,034)	(10.10%)
September	$ 16,444,505	$16,649,443	$204,939	1.25%
October	$ 16,416,765	$17,416,450	$999,685	6.09%
November	$ 17,142,869	$17,289,022	$146,153	0.85%
December	$ 16,691,987	$17,501,383	$809,396	4.85%
January	$ 18,296,176	$18,257,932	($38,244)	(0.21%)
February	$ 18,498,999	$16,732,628	($1,766,371)	(9.55%)
March	$ 18,693,627	$17,289,053	($1,404,574)	(7.51%)
April	$ 14,767,961	$17,320,058	$2,552,097	17.28%
May	$ 13,377,690	$17,368,547	$3,990,857	29.83%
June	$ 15,764,339	$15,438,689	($325,650)	(2.07%)
July	$ 20,794,522	$14,062,264	($6,732,258)	(32.38%)
August	$ 16,151,802	$15,340,875	($810,927)	(5.02%)
September	$ 13,720,977	$18,239,737	$4,518,760	32.93%
October	$ 12,911,484	$18,016,439	$5,104,955	39.54%
November	$ 15,550,583	$15,212,240	($338,343)	(2.18%)
December	$ 14,542,777	$13,780,252	($762,525)	(5.24%)
Total	**$ 201,477,350**	**$202,542,190**	**$1,064,840**	**0.53%**

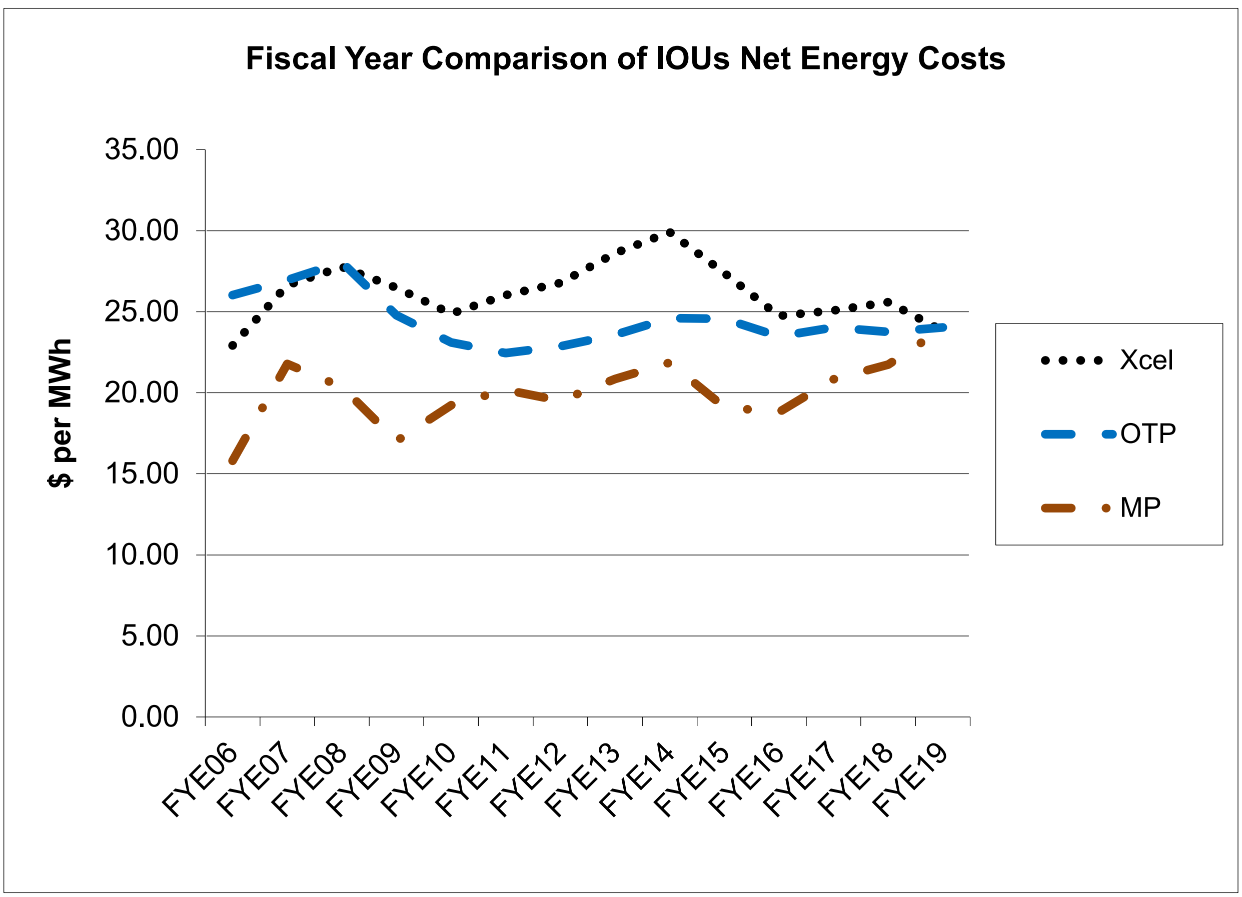
Source: Department's calculations.
(c) = (b) - (a)
(d)= (c)/(a)

Percent


Energy Cost Over(Under) Recovery
Minnesota Power
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
PERCENT OVER/(UNDER) RECOVERY
1987-88
1988-89
1989-90
1990-91
1991-92
1992-93
1993-94
1994-95
1995-96
1996-97
1997-98
1998-99
1999-00
2000-01
2001-02
2002-03
2003-04
2004-05
2005-06
2006-07
2007-08
2008-09
2009-10
2010-11
2011-12
2012-13
2013-14
2014-15
2015-16
2016-17
2017-18
2018-19
YEAR

Utilities Fuel and Purchased Power Costs in $ per MWh

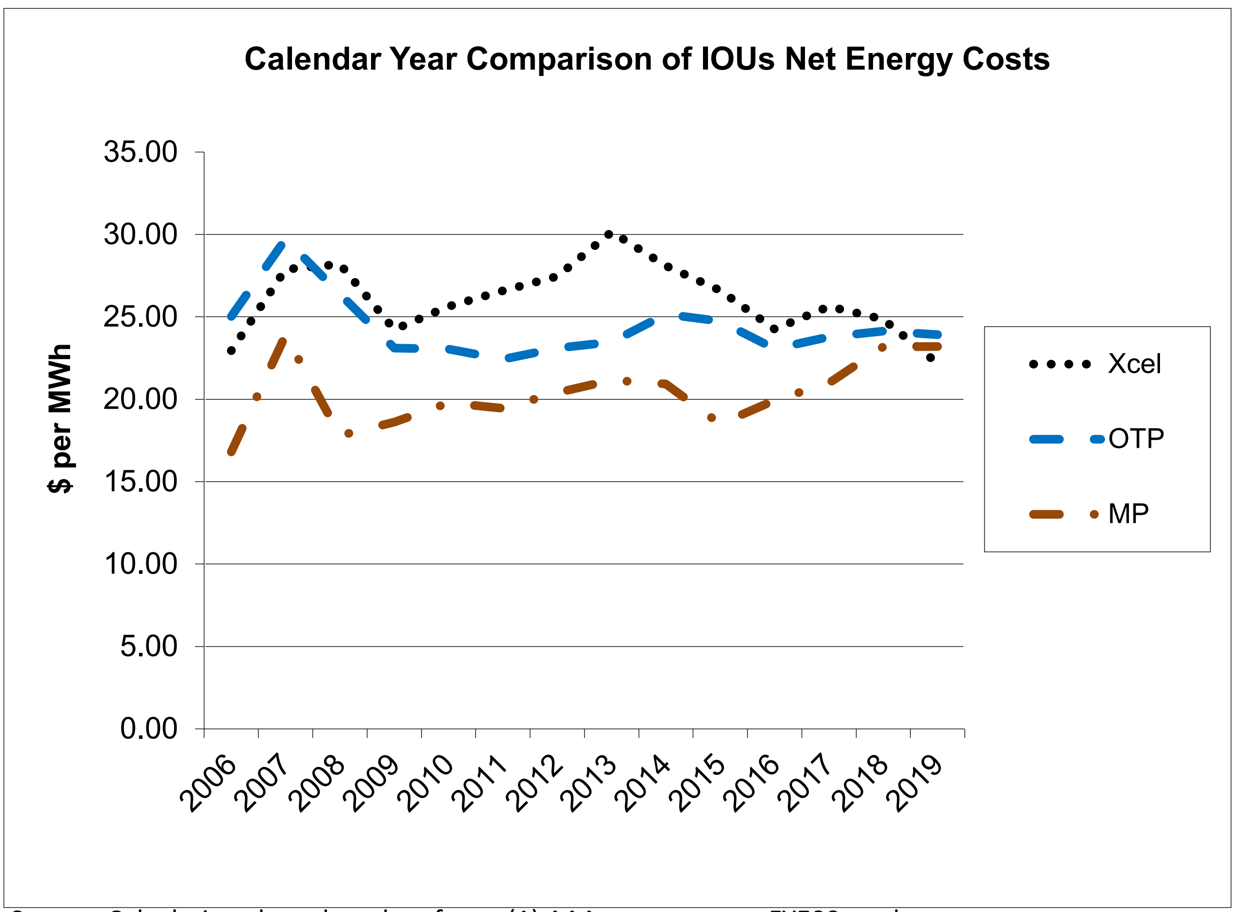
$/MWh	Xcel	OTP	MP
FYE06	22.92	26.02	15.80
FYE07	26.64	26.95	21.78
FYE08	27.77	28.05	20.37
FYE09	26.48	24.79	17.02
FYE10	24.89	23.10	19.24
FYE11	26.02	22.45	20.18
FYE12	26.77	22.86	19.52
FYE13	28.61	23.58	20.86
FYE14	29.91	24.61	21.85
FYE15	27.39	24.56	19.12
FYE16	24.74	23.47	18.79
FYE17	25.08	24.04	20.84
FYE18	25.60	23.75	21.75
FYE19	23.81	24.03	23.98
Min	22.92	22.45	15.80
Max	29.91	28.05	23.98



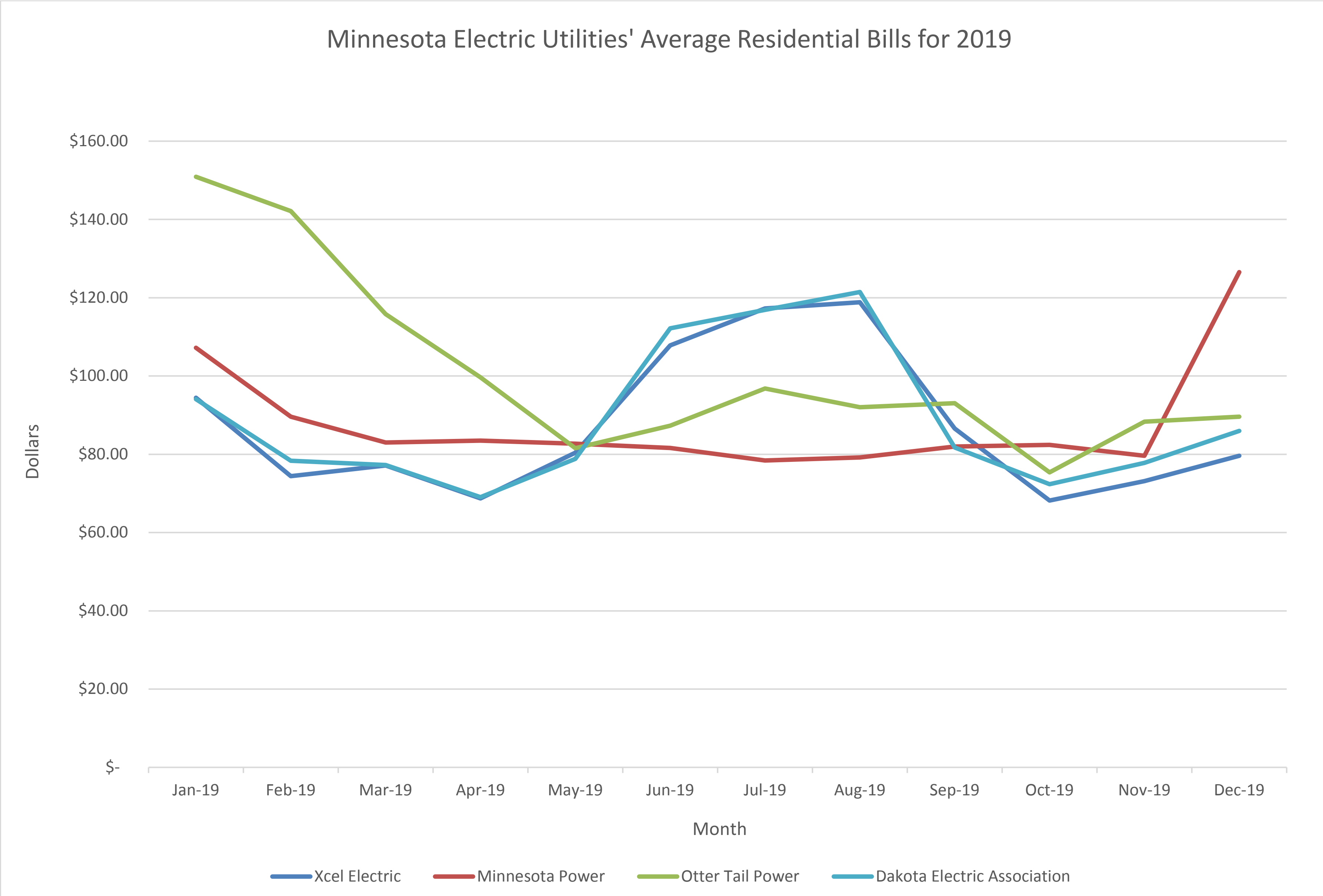
Source: Calculations based on data from: (1) AAA reports up to FYE09, and
(2) utilities' monthly FCA data emails after FYE09.

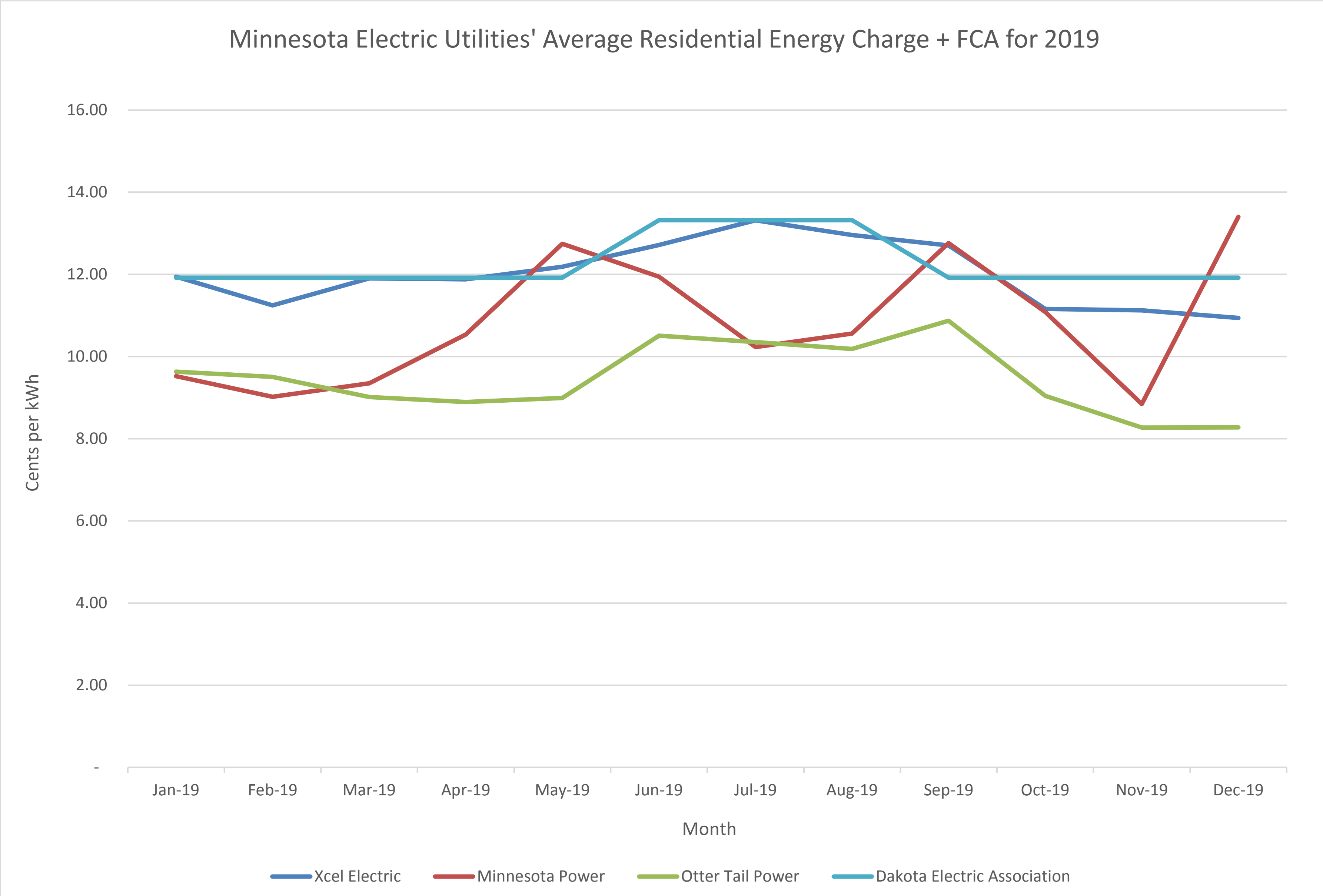
Utilities Fuel and Purchased Power Costs in $ per MWh

$/MWh	Xcel	OTP	MP
2006	22.95	25.03	16.81
2007	27.88	29.72	23.90
2008	28.19	26.39	17.80
2009	24.24	23.10	18.62
2010	25.64	23.04	19.79
2011	26.57	22.43	19.46
2012	27.46	23.11	20.40
2013	30.15	23.48	21.15
2014	28.09	25.15	20.92
2015	26.60	24.73	18.50
2016	24.25	23.06	19.94
2017	25.63	23.78	20.99
2018	24.86	24.14	23.18
2019	22.18	23.93	23.20
Min	22.18	22.43	16.81
Max	30.15	29.72	23.90



Source: Calculations based on data from: (1) AAA reports up to FYE09, and (2) utilities' monthly FCA data emails after FYE09.


Minnesota Electric Utilities' Average Residential Bills for 2019
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
Dollars
Jan-19
Feb-19
Mar-19
Apr-19
May-19
Jun-19
Jul-19
Aug-19
Sep-19
Oct-19
Nov-19
Dec-19
Month
Xcel Electric
Minnesota Power
Otter Tail Power
Dakota Electric Association


Minnesota Electric Utilities' Average Residential Energy Charge + FCA for 2019
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Cents per kWh
Jan-19
Feb-19
Mar-19
Apr-19
May-19
Jun-19
Jul-19
Aug-19
Sep-19
Oct-19
Nov-19
Dec-19
Month
Xcel Electric
Minnesota Power
Otter Tail Power
Dakota Electric Association

Minnesota Electric Utilities' Average Residential Bills for 2019
Page 1 of 2

Xcel Electric		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019 Monthly Av.
Av. residential monthly kWh usage		713	581	572	503	585	774	809	844	610	531	577	645	645
(1) Number of customers		1,145,435	1,146,449	1,148,018	1,149,014	1,149,827	1,149,641	1,149,833	1,150,637	1,150,662	1,152,460	1,153,189	1,154,330	13,799,495
(1) Residential sales (MWh)		816,740	666,296	656,590	578,285	673,007	889,765	930,508	970,711	701,799	612,228	665,192	744,470	8,905,592
(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	0.0924	0.0924	0.0924	0.0924	0.0924	0.0924	0.1030	0.1030	0.1030	0.1030	0.0880	0.0880	0.0880	
June - Sep	0.1030													
Oct - Dec	0.0880													
En. Charge X kWh usage		$ 65.89	$ 53.71	$ 52.85	$ 46.51	$ 54.09	$ 79.72	$ 83.36	$ 86.90	$ 62.83	$ 46.76	$ 50.78	$ 56.77	
(2) Fuel Clause Adjustment ($/kWh)		0.02702	0.02003	0.02661	0.02642	0.02947	0.02416	0.03015	0.02656	0.02404	0.02357	0.02322	0.02137	
FCA X kWh usage		$ 19.27	$ 11.64	$ 15.22	$ 13.30	$ 17.25	$ 18.70	$ 24.40	$ 22.41	$ 14.66	$ 12.52	$ 13.39	$ 13.78	
CIP surcharge ($/kWh)														
(2) Jan-Sep 2019	$ 0.001813	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.001682	$ 0.001682	$ 0.001682	
(2) Oct-Dec 2019	$ 0.001682													
CIP surchrg. X customer's usage		$ 1.29	$ 1.05	$ 1.04	$ 0.91	$ 1.06	$ 1.40	$ 1.47	$ 1.53	$ 1.11	$ 0.89	$ 0.97	$ 1.08	
Total av. resid. monthly bill		$ 94.45	$ 74.40	$ 77.11	$ 68.72	$ 80.40	$ 107.83	$ 117.23	$ 118.84	$ 86.59	$ 68.18	$ 73.14	$ 79.64	$ 87.21
Av. Resid. energy charge + FCA ($/kWh)		11.94	11.24	11.90	11.88	12.19	12.72	13.32	12.96	12.71	11.16	11.13	10.94	12.01

(1) Source: Xcel Electric's 2018 Annual Jurisdictional Report, page Sales & Degree E-29, May 1, 2019 (Docket No. 19-4).
(2) Source: Xcel Electric's response to IR 10 in Docket No. E999/AA-20-171.

Minnesota Power		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019 Monthly Av.
Av. residential monthly kWh usage		980	848	754	678	559	587	667	655	566	653	782	864	716
(1) Number of customers		122,416	122,216	122,266	122,355	122,476	123,165	122,634	122,775	122,676	122,661	122,512	122,528	1,470,680
(1) Residential sales (MWh)		119,940	103,661	92,148	82,903	68,520	72,249	81,853	80,383	69,381	80,081	95,809	105,873	1,052,800
(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-Dec													
0 to 400 kWh	0.07423	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	$ 29.69	
401 to 800 kWh	0.09767	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	$ 38.97	
801 to 1200 kWh	0.12113	$ 21.66	$ 5.71										$ 48.33	
over 1200 kWh	0.14653												$ -	
Total monthly energy charge		$ 90.32	$ 74.38	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 68.66	$ 116.99	
(2) Fuel Clause Adjustment ($/kWh)		0.00303	0.00250	0.00239	0.00404	0.00470	0.00237	(0.00054)	0.00073	0.00622	0.00566	0.00065	(0.00138)	
FCA X kWh usage		$ 2.97	$ 2.12	$ 1.80	$ 2.74	$ 2.63	$ 1.39	$ (0.36)	$ 0.48	$ 3.52	$ 3.70	$ 0.51	$ (1.19)	
(2) CIP surcharge Jan-July	$ 0.006040													
Aug-Dec	$ 0.003162													
CIP (CPA+CCRC) surcharge X customer's bill		$ 5.92	$ 5.12	$ 4.55	$ 4.09	$ 3.38	$ 3.54	$ 2.11	$ 2.07	$ 1.79	$ 2.06	$ 2.47	$ 2.73	
Total av. resid. monthly bill		$ 107.20	$ 89.62	$ 83.02	$ 83.49	$ 82.67	$ 81.60	$ 78.41	$ 79.21	$ 81.97	$ 82.42	$ 79.64	$ 126.53	$ 87.98
Av. Resid. energy charge + FCA ($/kWh)		9.52	9.02	9.35	10.54	12.74	11.94	10.23	10.56	12.76	11.08	8.84	13.40	10.83

(1) Source: MP's 2018 Annual Jurisdictional Report, page E-29 extra, May 01, 2019. (Docket 19-4)
(2) Source: MP's response to IR 10 in Docket No. E999/AA-20-171

Minnesota Electric Utilities' Average Residential Bills for 2019

Page 2 of 2

Otter Tail Power	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019 Monthly Av.
Av. residential monthly kWh usage	1,456	1,384	1,169	1,004	793	733	835	803	761	721	943	958	962
(1) Number of customers	48,349	48,318	48,360	48,290	48,361	49,271	49,327	49,410	49,255	49,112	48,410	48,497	584,960
(1) Residential Sales (MWh)	70,408	66,884	56,519	48,489	38,360	36,117	41,211	39,654	37,489	35,393	45,663	46,476	562,663
(2) Customer Charge	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	$ 9.75	
(2) Energy charge ($/kWh)	0.09064	0.09064	0.09064	0.09064	0.09064	0.10540	0.10540	0.10540	0.10540	0.0864	0.0864	0.0864	
Total monthly energy charge	$ 131.99	$ 125.47	$ 105.93	$ 91.01	$ 71.90	$ 77.26	$ 88.06	$ 84.59	$ 80.22	$ 62.26	$ 81.50	$ 82.80	
(2) Fuel Clause Adjustment ($/kWh)	0.00567	0.00439	(0.00050)	(0.00168)	(0.00070)	(0.00035)	(0.00187)	(0.00354)	0.00331	0.00404	(0.00368)	(0.00362)	
FCA X kWh	$ 8.26	$ 6.07	$ (0.58)	$ (1.69)	$ (0.56)	$ (0.25)	$ (1.57)	$ (2.84)	$ 2.52	$ 2.91	$ (3.47)	$ (3.47)	
(2) CIP surcharge	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	0.00600	
CIP surchrg. X customer's bill	$ 0.90	$ 0.85	$ 0.69	$ 0.59	$ 0.49	$ 0.52	$ 0.58	$ 0.55	$ 0.55	$ 0.45	$ 0.53	$ 0.53	
Total av. resid. monthly bill	$ 150.90	$ 142.14	$ 115.79	$ 99.67	$ 81.57	$ 87.28	$ 96.82	$ 92.04	$ 93.05	$ 75.38	$ 88.30	$ 89.62	$ 101.05
Av. Resid. energy charge + FCA ($/kWh)	9.63	9.50	9.01	8.90	8.99	10.51	10.35	10.19	10.87	9.04	8.27	8.28	9.46

(1) Source: OTP's 2018 Annual Jurisdictional Report, page E-29, May 10, 2019. (Docket 19-4)
(2) Source: OTP's response to IR 10 in Docket No. E999/AA-20-171.

Dakota Electric Association	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019 Monthly Av.
(1) Av. residential monthly kWh usage	713	581	572	503	585	774	809	844	610	531	577	645	645
(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	$ 83.28	$ 67.88	$ 66.80	$ 58.78	$ 68.36	$ 101.23	$ 105.85	$ 110.35	$ 71.24	$ 62.05	$ 67.37	$ 75.33	
(2) Power Cost Adjustment ($/kV	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	
Power Cost Adj. X kWh	$ 1.71	$ 1.39	$ 1.37	$ 1.21	$ 1.40	$ 1.86	$ 1.94	$ 2.02	$ 1.46	$ 1.27	$ 1.38	$ 1.55	
(2) CIP & Property tax surcharge ($/kWh)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
DSM surchrg. X customer's bill	$ 0.07	$ 0.06	$ 0.06	$ 0.05	$ 0.06	$ 0.08	$ 0.08	$ 0.08	$ 0.06	$ 0.05	$ 0.06	$ 0.06	
Total av. resid. monthly bill	$ 94.07	$ 78.34	$ 77.23	$ 69.04	$ 78.83	$ 112.17	$ 116.87	$ 121.46	$ 81.76	$ 72.38	$ 77.82	$ 85.94	$ 88.82
Av. Resid. energy charge + FCA ($/kWh)	11.92	11.92	11.92	11.92	11.92	13.32	13.32	13.32	11.92	11.92	11.92	11.92	12.27

(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 10 in Docket No. E999/AA-20-171

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Public 2020 Electric Annual Automatic Adjustment Report (AAA)

Docket No. E999/AA-20-171

Dated this **15th** day of **April 2020**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_20-171_AA-20-171
Daniel	Beckett	daniel.beckett@state.mn.us	Department of Commerce	85 7th Pl E #500 Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_20-171_AA-20-171
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-171_AA-20-171
Nancy	Campbell	Nancy.campbell@state.mn.us	Department of Commerce	121 Seventh Place EastSuite 200 St. Paul, MN 551012145	Electronic Service	No	OFF_SL_20-171_AA-20-171
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-171_AA-20-171
Hillary	Creurer	hcreurer@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_20-171_AA-20-171
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_20-171_AA-20-171
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-171_AA-20-171
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-171_AA-20-171
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_20-171_AA-20-171

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Matt	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-171_AA-20-171
Corey	Hintz	chintz@dakotaelectric.com	Dakota Electric Association	4300 220th Street Farmington, MN 550249583	Electronic Service	No	OFF_SL_20-171_AA-20-171
Mark	Johnson	Mark.A.Johnson@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_20-171_AA-20-171
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-171_AA-20-171
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_20-171_AA-20-171
Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy	414 Nicollet Mall 7th Floor Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_20-171_AA-20-171
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_20-171_AA-20-171
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_20-171_AA-20-171
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-171_AA-20-171
Samir	Ouanes	samir.ouanes@state.mn.us	Department of Commerce	85 7th Place East, Suite 500 St Paul, MN 55101	Electronic Service	No	OFF_SL_20-171_AA-20-171

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-171_AA-20-171
Stephen	Rakow	stephen.rakow@state.mn.us	Department of Commerce	Suite 280 85 Seventh Place East St. Paul, MN 551012198	Electronic Service	No	OFF_SL_20-171_AA-20-171
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-171_AA-20-171
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-171_AA-20-171
Cary	Stephenson	cStephenson@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_20-171_AA-20-171
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_20-171_AA-20-171
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_20-171_AA-20-171
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_20-171_AA-20-171
Michael	Zajicek	Michael.Zajicek@state.mn.us	Department of Commerce	85 East Seventh Place Suite 500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_20-171_AA-20-171