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MAR 14 2005
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

OTTER TAIL POWER COMPANY

VIA OVERNIGHT DELIVERY

March 10, 2005

Ms. Pamela Bonrud, Executive Director
South Dakota Public Utilities Commission
State Capitol
500 East Capitol Street
Pierre, SD 57501-5070

Re: In the Matter of the Petition of Otter Tail Corporation d/b/a Otter Tail Power Company to revise its Fuel Adjustment Clause Tariff to accommodate MISO Day 2 charges, SDPUC Docket No. ____________________

Dear Ms. Bonrud,

Pursuant to South Dakota Codified Laws Section 49-34A-10 and Administrative Rules of South Dakota ("ARSD") Part 20:10:13:11, enclosed for filing please find an original and 10 copies of the Otter Tail Corporation d/b/a Otter Tail Power Company, petition for approval of revisions to its Fuel Adjustment Clause (FAC) tariff to accommodate MISO Day 2 charges.

Otter Tail Power Company is requesting expedited consideration of this petition as the MISO Day 2 market begins April 1, 2005. In this petition, Otter Tail Power Company requests authority to implement our proposed FAC tariff effective with the start of the MISO Day 2 Market on April 1, 2005, subject to any refund which may result from the South Dakota Public Utilities Commission's final order in this matter. As a practical matter, the calculation of our FAC will not reflect Day 2 transactions until May. This effective date insures the netting of MISO Day 2 costs and revenues starting April 1.

Should you have any questions with respect to this filing, please contact me at (218) 739-8289 or bbrutlag@otpco.com.

Very truly yours,

Bernadeen Brutlag

Bernadeen Brutlag
Manager, Regulatory Services

Enclosures

STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

In the Matter of the petition of Otter Tail Corporation d/b/a Otter Tail Power Company, to revise its Fuel Adjustment Clause Tariff to accommodate MISO Day 2 charges.

Docket No. ________________

Petition of Otter Tail Power Company to Revise its Fuel Adjustment Clause Tariff to Accommodate MISO Day 2 Charges

I. INTRODUCTION

Pursuant to South Dakota Codified Laws Section 49-34A-25 and Administrative Rules of South Dakota ("ARSD") Part 20:10:13:11, Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail"), petitions the South Dakota Public Utilities Commission ("the Commission") for approval of revisions to its Fuel Adjustment Clause ("FAC") tariff. The Midwest Independent Transmission System Operator, Inc. ("MISO" or "Midwest ISO") is transitioning to the "Day 2 Market," under its Transmission and Energy Markets Tariff ("TEMT") and under the direction of the Federal Energy Regulatory Commission ("FERC"). The Day 2 Market will change how MISO utilities purchase energy for delivery to serve native retail load.

With implementation of the Day 2 Market, Otter Tail respectfully petitions the Commission to affirm that the costs and revenues associated with serving Otter Tail's retail customers through participation in the wholesale electric energy market are appropriate for recovery and pass-through within the FAC. As such, Otter Tail requests that the Commission approve a revised FAC tariff (designated M-60S). The MISO Day 2 market begins April 1, 2005. In this petition, Otter Tail Power Company requests authority to implement our proposed FAC tariff effective with the start of the MISO Day 2 Market on April 1, 2005, subject to refund. As a practical matter, the calculation of our FAC will not reflect Day 2 transactions until May.

This effective date insures the netting of MISO Day 2 costs and revenues starting April 1. For these reasons, Otter Tail requests an expedited review and approval of this petition.

II. GENERAL FILING INFORMATION

Pursuant to ARSD Part 20:10:13:12, Otter Tail provides the following general information.

A. Name, Address, and Telephone Number of Utility.

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215 South Cascade Street
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(218) 739-8200

B. Name, Address, and Telephone Number of Utility Attorney.

Bruce Gerhardson
Associate General Council
Otter Tail Corporation
215 South Cascade Street
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Fergus Falls, MN 56538-0496
(218) 998-7108

C. Date of Filing and Date Changes Will Take Effect.

This petition is being filed on March 10, 2005 and Otter Tail requests approval effective as of April 1, 2005.

D. Rule Controlling Schedule for Processing the Filing.

ARSD Part 20:10:13:15 requires a 30-day notice to the Commission of a proposed change in a utilities tariff schedule, after which time the proposed changes take effect unless suspended. Otter Tail requests an expedited and informal proceeding, including any variances that may be necessary.

E. Rule Controlling the Notice of the proposed tariff change.

ARSD Part 20:10:13:18 requires applications for permission to file changed rate schedules and revised sheets on less than 30 days notice, the utility shall state fully the circumstances and conditions which are relied upon as justifying the application. Otter Tail has complied with ARSD Part 20:10:13:18 in this petition.

F. Rule Controlling the Report of Tariff Changes.

ARSD Part 20:10:13:26 requires utilities to submit a report to the Commission of tariff schedule changes on notice. Included in Attachment D, is Otter Tail's South Dakota "Report of Tariff Schedule Changes" form.

G. Title of Utility Employee Responsible for Filing.

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III. BACKGROUND AND IMPACTS

A. Background

On August 6, 2004, FERC conditionally accepted for filing MISO's TEMT.[1] On November 8, 2004, FERC denied all requests for rehearing of the August 6 Order.[2] The TEMT contains several modules. Module A is a list of general terms. Module B relates to the provision of network and point-to-point transmission service and sets forth the related charges for transmission access, including Schedule 10 fees associated with MISO's operational control over transmission. Most relevant to the instant filing, Module C includes the rates, terms and conditions necessary for the implementation of a region-wide, security constrained, centralized economic dispatch platform energy market. Day-Ahead and Real-Time Energy Markets, based on Locational Marginal Pricing ("LMP") and hedged with Financial Transmission Rights ("FTRs"), support this platform. This new market design for energy, often referred to as the "Day 2 Market," is currently slated to begin on April 1, 2005.

Implementation of the TEMT and Day 2 Market will change the way the Company purchases energy for delivery to serve its retail native load. All Company generation and load will participate in the Day Ahead and Real Time Markets, and generation will be subject to economic dispatch by MISO. As a result, generation is offered into the market and if it clears the market, is paid the market-clearing price by the MISO and will be booked as a wholesale sale. Correspondingly, load bids into the market and purchased energy from the Midwest ISO and purchases made by Otter Tail will be booked as wholesale energy purchases. The net effect is that from an accounting perspective, most transactions to serve retail customers will be sourced by transactions at LMP prices with MISO. This contrasts with the present system of most of the customer requirements being served by self-generation with any remaining energy needs being met from market purchases. There are provisions to self-schedule generation; this does not avoid the market, but instead ensures that the designated resource is taken by the market and paid the market-clearing price at the injection point. Self-scheduling ensures that a unit runs if it is

[1] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶101,163 (2004) ("August 6 Order").
[2] Midwest Independent Transmission System Operator, Inc., 109 FERC ¶61,157 (2004) ("November 8 Order").

online. However, the MISO commitment process may determine that a unit should be de-committed. Therefore, designating the unit as must-run in the Reliability Assessment Commitment process and self-scheduling are required to ensure that unit operates. Bilateral transactions can occur at a FERC approved wholesale rate/pricing methodology. These transactions avoid the energy portion of the LMP; however, they do not avoid congestion and loss charges or credits. Otter Tail can also continue to purchase power from outside of MISO, however these transactions are subject to the same MISO charges as a bilateral internal to MISO.

B. MISO Day 2 Impact on Accounting and Current FAC

The MISO TEMT contains several modules that will change the way Otter Tail accounts for power supply costs and revenues. The most significant changes result from Module C, which includes the rates, terms and conditions necessary for the implementation of a region-wide, security constrained, centralized economic dispatch platform energy market. Day-Ahead and Real-Time Energy Markets, based on LMP and hedged with FTRs, support this platform.

Otter Tail's current FAC was developed for operations prior to the Day 2 Market. As a market participant of MISO, Otter Tail is required to participate in MISO and MISO Day 2. Presently, MISO has 32 charge (credit) types governed by the TEMT that flow through settlement statements. All of these charge types are necessary to purchase and sell energy within MISO efficiently, effectively and fairly. Not all charge types apply to all market participants; however, if any of the charges or credits were excluded from the market, all participants would not be credited or charged correctly. The same is true for costs recovered within the FAC. All charges and credits that apply to Otter Tail need to be included to provide an accurate cost of purchasing energy in the Day 2 Market. A detailed discussion of Day 2 Market components can be found in Attachment B. The 32 components are as follows:

1. Day-Ahead Charge Types

The following Charge Types are utilized in the MISO Day-Ahead Settlement Statements.

Day-Ahead Asset Energy Amount

Day-Ahead Financial Bilateral Transaction Congestion Amount
Day-Ahead Financial Bilateral Transaction Loss Amount
Day-Ahead Market Administration Amount
Day-Ahead Non-Asset Energy Amount
Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements
Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements
Day-Ahead Congestion Rebate on Option B Grandfathered Agreements
Day-Ahead Losses Rebate on Option B Grandfathered Agreements
Day-Ahead Revenue Sufficiency Guarantee Distribution Amount
Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount
Day-Ahead Virtual Energy Amount

2. Financial Transmission Rights Charge Types

The following Charge Types are utilized in the MISO Financial Transmission Rights Settlement Statements.

Financial Transmission Rights Hourly Allocation Amount
Financial Transmission Rights Market Administration Amount
Financial Transmission Rights Monthly Allocation Amount
Financial Transmission Rights Transaction Amount
Financial Transmission Rights Yearly Allocation Amount

3. Real-Time Charge Types

The following Charge Types are utilized in the MISO Real-Time Settlement Statements.

Real-Time Asset Energy Amount
Real-Time Distribution of Losses Amount
Real-Time Financial Bilateral Transaction Congestion Amount
Real-Time Financial Bilateral Transaction Loss Amount
Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements
Real-Time Losses Rebate on Carve-Out Grandfathered Agreements
Real-Time Market Administration Amount
Real-Time Miscellaneous Amount
Real-Time Net Inadvertent Distribution Amount
Real-Time Non-Asset Energy Amount
Real Time Revenue Neutrality Uplift Amount
Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount
Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount
Real-Time Uninstructed Deviation Amount
Real-Time Virtual Energy Amount

The 32 MISO Day 2 charges will likely be booked into a variety of FERC accounts such as the following:

Account 555 – Purchase Power Expense
Account 565 – Transmission of Electricity by Others
Account 447 – Sales for Resale
Account 456 – Other Electric Revenues

FERC has not provided accounting guidance regarding the MISO Day 2 charges. The netting of these MISO charges into Account 555 – Purchase Power may be a viable option only if acceptable by FERC. Otter Tail does not expect FERC to accept a net accounting approach. Otter Tail prefers to revise its FAC to allow for the recovery of the 32 MISO Day 2 charges and revenues. This variance allows a fix to the existing FAC whether or not FERC allows net accounting.

The following simplified table provides an example of current FAC components (without costs or sales for intersystem transactions to help emphasize the impact of the MISO Day 2 costs) along with Day 2 Market components. The table also provides the mapping to FERC account of current FAC components and the probable mapping of a sample of Day 2 Market components.

TABLE 1

Otter Tail Power Company

Illustration of Impacts of MISO Day 2

Operations/Accounting/FAC

			Current FAC		Proposed FAC
Line	Description of Cost Components	FERC Account*	Current	MISO Day 2	MISO Day 2
1	**Fuel Consumed**	501	3.3	3.3	3.3
	Generated 300 MWh x $11/MWh				
2	**Purchased Power Energy Consumed**	555	3.6		
	Purchased Power - 90 MWh x $40/MWh				
3	**Purchased Steam**	503			
4	**Released Energy Credits**	555			
5	**Cost of Buyback Energy Credits**	555			
6	Day-Ahead Asset Energy Amount	447		(10.3)	(10.3)
	Revenue from sales to Day-ahead markets - 300 MWh x $34.40/MWh				
7	Real-Time Asset Energy Amount	447			
	Revenue from Sales to Real-Time Market				
8	Day-Ahead Asset Energy Amount	555		14.63	14.63
	Cost of Purchases to Day-Ahead Markes - 390 MWh x $37.50/MWh				
9	Real-Time Asset Energy Amount	555			
	Cost of Purchases of Real-Time Market				
10	Financial Transmission Rights Hourly Allocation Amount	456		(0.390)	(0.390)
11	Real-Time Distribution of Losses Amount	456		(0.390)	(0.390)
	Marginal Loss Compensation				
12	Financial Transmission Rights Market Administration Amount	565		0.016	0.016
	Schedule 16 - .053/MWh x 300 MWh				
13	Day-Ahead Market Administration Amount	565		0.042	0.042
	Schedule 17 - $0.081/MWh x 690 MWh				
14	**Less Costs Recovered via Intersystem Sales**		-	(3.3)	-
	MWh				
15	**Net Cost of Power**		**6.9**	**14.63**	**6.883**
	Purchased Power MWh				

MWh Sales of Electricity		0.35	0.35	0.35
Average Cost ($MWh)		19.71	41.79	19.67
FAC base ($/MWh)		15.460	15.460	15.460
FAC ($/MWh)		4.25	26.33	4.21

Items in Gray not included in calculation of FAC

* Subject to FERC Rulemaking

Table 1 calculates a fuel adjustment under the existing FAC for the current market (assuming $0 over/(under) recovery) and the MISO Day 2 Market. The column labeled "Current" shows that prior to MISO Day 2, Otter Tail's FAC includes fuel and purchased energy for retail customers.

The application of our existing FAC tariff to the MISO Day 2 Market may result in a fuel adjustment that exceeds the cost of providing service. In the Day 2 Market, Otter Tail would offer its generation into the market and bid its load (purchase power at LMP). As explained previously, from an accounting perspective, most MISO Day 2 transactions to serve retail customers will be wholesale transactions at LMP prices with MISO as the counterparty. These transactions will appear in account 555, purchased power. The second column of the above example shows that, without a revision to the FAC tariff to include offsetting revenues (shaded items), the FAC would be overstated.

Otter Tail's proposed FAC revision would allow costs and revenues linked to its load serving obligation to be included in the fuel clause adjustment. The far right column shows that when all the costs and revenues are included, the fuel adjustment will approximate the results of its current FAC. The proposed revision requires allowing the inclusion of amounts recorded in accounts other than Fuel (501) and Purchased Power (555).

While FERC has offered little guidance for accounting for LMP transactions, our interpretation of FERC accounting guidelines would dictate that portions of the LMP transactions would appear in the accounts listed in the example. Attachment A provides a series of examples of how various market scenarios would influence the FAC.

IV. REQUESTED FAC REVISION AND IMPLEMENTATION

A. Requested Revision to Otter Tail's Fuel Adjustment Clause

Presently, Otter Tail and other South Dakota electric utilities recover the cost of purchased energy, fuel, delivered losses, and congestion (in the form of redispatched units) through the FAC (Otter Tail estimates approximately 11,000 of its South Dakota customers are subject to its FAC). When MISO implements the Day 2 Market, we will continue to incur these costs, but the name, form and means of calculating such costs and revenue will change. As explained herein, these new charges and revenues will still reflect the fuel and purchased energy cost of serving our retail electric customers.

We believe that the proposed revision to the FAC tariff provides for the inclusion of all costs and revenues associated with serving Otter Tail's retail customers through our participation in the MISO Day 2 Market. Specifically, these costs and revenues result from Otter Tail's involvement in Day-Ahead, Real-Time and Financial Transmission Rights Markets and its use of bilateral transactions. The revision to the FAC tariff also anticipates that the costs and revenues to fulfill its load serving obligation may evolve as wholesale electric energy markets evolve. The revised FAC tariff, M-60S, provided as Attachment C, adds a new component inserted as 6. (indicated by the N in the right hand margin of the attached tariff sheet) which reads as follows:

> 6. Costs or revenues linked to the utility's load serving obligation, associated with participation in wholesale electric energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the energy markets.

The previous item 6. is renumbered as item 7. and the previous item 7. is renumbered as item 8. as noted by the L right hand margin the attached tariff sheet. As stated previously in this filing, Otter Tail strongly requests a revision to its tariff M-60S to allow the use of the accounts shown in table 1, to allow flow-through of revenues and costs. To effectuate the FAC tariff revision, Otter Tail is requesting the specific ability to flow through the Day 2 costs which use FERC accounts (subject to FERC Rulemaking) not currently defined in its FAC tariff. These costs and accounts are used in Table 1 shown previously in this filing and include: Day-ahead Energy and Real-Time Asset amount using FERC account 447 (lines 6 & 7 in the table), Financial Transmission Rights hourly allocation and the Real-Time Distribution of Losses amounts which use FERC account 456 (lines 10 & 11 in table 1), Financial Transmission Rights

Market Administration and Day-Ahead Market Administration Amounts which use FERC account 565 (lines 12 & 13 in the table).

Otter Tail respectfully requests approval of its revised FAC tariff to be effective with the implementation of MISO's TEMT. The proposed revision to the FAC tariff is not an expansion of the scope of the FAC; rather, the revised FAC tariff continues to reflect those costs and revenues supporting the cost of fuel and energy delivered to Otter Tail's retail customers. In addition, in implementing the revised FAC tariff, Otter Tail will continue to use the same principles for allocating native and intersystem wholesale costs. Otter Tail believes that its proposal to amend the FAC tariff will result in rate recovery of the overall costs for fuel and energy comparable to the costs contemplated to be recovered by the FAC statute and rules and as such, believes that the Commission can and should make the affirmative findings requested by this Petition.

B. Schedule 16, Schedule 17 and Uplift Charges

Otter Tail seeks FAC recovery because these FERC-approved rates are assessed for the procurement of energy for its customers. These costs are generally assessed on a MWh basis and should be included in the FAC.

Schedule 16, Financial Transmission Rights Administrative Service Cost Recovery Rider, allows MISO to recover costs associated with providing FTR service and is assessed in the settlement process. Schedule 17, Energy Market Support Administrative Cost Recovery Rider, allows MISO to recover the costs associated with providing the Day-Ahead and Real-Time Energy Market Services. Schedule 17 will be recovered through a Transaction Administrative Rate and an Energy Market Administrative Rate. The Transaction Administrative Rate shall be assessed on the number of hourly bid and offered schedules in the Day-Ahead Energy Market. The Energy Market Administrative Rate shall be assessed on Otter Tail's related activity volumes in the Day-Ahead and Real-Time Energy Markets.

FERC approved, as part of MISO's TEMT, Schedules 16 and 17—in addition to thirty other charges. Otter Tail believes that these charges should be recovered in the FAC. These new charges are required in the procurement of energy for Otter Tail customers and the costs are assessed primarily on an energy basis.

C. Settlements

The settlement process will provide the detail charges for FAC calculations for energy purchased in the Day 2 Market. The settlements process involved with the Day 2 Market will add a significant layer of complexity to Otter Tail's billing and accounting processes. Otter Tail has 12 generation and 3 load nodes. MISO will bill Otter Tail on a weekly basis. The bill will be settled for Day-Ahead and Real-Time Markets and will settle LMPs and FTRs. Each will be supported with individual settlement statements and a summary settlement statement for each operating day over multiple periods including a 7 day ("S7"), 14 day ("S14"), 55 day ("S55") and 105 day ("S105") settlement period as well as a dispute process following settlement. Otter Tail has been actively preparing for implementing the back office support for MISO Day 2 and is willing to provide additional information to the Commission and/or agency staffs of how Otter Tail intends to manage this process.

D. Additional Reporting Requirements

Upon request, Otter Tail will submit the various components to Otter Tail's MISO Day 2 Market charges that impact the FAC. This additional information will help the Commission and interested parties monitor the Day 2 Market impacts on Otter Tail's FAC. Otter Tail is willing to include additional information if the Commission believes it is needed.

E. Implementation Prior to Final Commission Decision

Otter Tail requests authority to implement our proposed FAC tariff effective with the start of the MISO Day 2 Market on April 1, 2005. As a practical matter, the calculation of our FAC will not reflect Day 2 transactions until May. This effective date insures the netting of MISO Day 2 costs and revenues through the FAC starting April 1. If the Commission's decision should result in Otter Tail having made excess FAC collections, Otter Tail would make appropriate refunds. Any refund amount would include interest and use the FAC as the refund mechanism, to be completed within 120 days of the Final Commission Order.

F. Explanation.

1. The proposed tariff changes will impact all classes of electric service.
2. The proposed Tariff sheets are:

   Section No. 3, Volume I, 7th Rev. Sheet No. 98-Super. 52, Canceling 6th Revised Sheet No. 52, Rate Designation M-60S
3. The proposed tariff changes apply to the following types of service:
   - Commercial Time-of-Use
   - Farm Service
   - Fire Sirens
   - General Service
   - General Service - Controlled Demand
   - General Service Electric Climate Control
   - General Service Time of Use Rider
   - Irrigation Service
   - Large General Service
   - Large General Service Off Peak Rider
   - Real Time Pricing
   - Residential Service
   - Residential Service-Controlled Demand
   - Water Heating
4. The affected tariffs are applicable to all areas served with electricity serviced by Otter Tail in South Dakota.
5. There are no additional special conditions, limitations, qualifications or restrictions upon the proposed tariffs.

G. Financial Impact

Not available

H. Precedential Effect

None.

V. CONCLUSION

For the foregoing reasons, Otter Tail respectfully requests that the Commission approve the proposed revisions to its FAC tariff, to be effective as of the earliest possible date.

Dated: March 10, 2005

Respectfully submitted,

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY

By: Bernadeen Brutlag

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ATTACHMENT A

MISO DAY 2 TRANSACTION EXAMPLES

The following examples show how the proposed FCA treatment for TEMT related costs and revenues would apply, and compares the results to the costs currently included in the FCA.

Scenario 1
Hedging with Generating Resources And No Congestion

Otter Tail bids 100 MW of load demand while at the same time offering 100 MW of generation from its Coyote Plant for 24 hours in the Day-Ahead market. The Day-Ahead market settles at an LMP price of $21.00/MWH ($20 energy and $1 of marginal losses) for energy at this bus to the designated load node (the LMP price for generation). 100 MW of Otter Tail load bid gets picked up at the Day Ahead price of $21.50/MWH. (The difference in load vs. generation LMP prices is caused by a different marginal loss component for each). The fuel cost for Coyote for this period is $10/MWH. FTRs are not a factor in this example as there is no congestion in the Day Ahead market.

Resulting Charges:

- Otter Tail pays $21.50/MWH (for 100 MW*24 hours) to the Midwest ISO.
- The Company incurs costs of $10/MWH for fuel.
- Otter Tail receives a payment of $21.00/MWH (for 100 MW*24 hours) from the Midwest ISO for its generation.

Alternative FCA Outcomes for Customers:

- Today: Customers are charged $10 for cost of fuel.
- Day 2 with no Change in FCA Tariff: Customers are charged $21.50 as an energy purchase from the Midwest ISO.
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load, or $10.50/MWH (reflecting the differential in LMP prices due to marginal losses).[3]

[3] Although not shown, Otter Tail Power will be compensated for the difference between marginal and average losses by the Midwest ISO. Thus, Otter Tail Power proposes to return these rebated amounts associated with native load through the FCA. The mechanism for the return of this revenue is not known at this time. In addition, we do not attempt to reflect MISO operational costs in this or any of the other scenarios.

Scenario 2
Hedging With Generating Resources with Congestion

Otter Tail bids 100 MW of load demand while at the same time offering 100 MW of generation from its Coyote Plant for 24 hours in the Day-Ahead market. The Day-Ahead market settles at an LMP price of $21.00/MWH ($20 energy and $1 of marginal losses) for energy from this bus to the designated load node (the LMP price for generation). 100 MW of Otter Tail load bid gets picked up at the Day Ahead price of $51.50/MWH. (Comprised of $20 energy, $30 for congestion and $1.50 for marginal losses). The difference in load vs. generation LMP prices is caused by a congestion cost and different marginal loss component for each). The fuel cost for Coyote for this period is $10/MWH. This example assumes that Otter Tail obtained FTRs for the Coyote path for the entire 100 MW and the entire 24 hours.

Resulting Charges:

- Otter Tail pays $51.50/MWH (for 100 MW*24 hours) to the Midwest ISO.
- The Company incurs costs of $10/ MWH for fuel.
- Otter Tail receives a payment of $21.00/MWH (for 100 MW*24 hours) from the Midwest ISO for its generation.
- Otter Tail receives FTR revenues of $30/MWH (for 100 MW*24 hours) from the Midwest ISO.

Alternative FCA Outcomes for Customers:

- Today: Customers are charged $10 for cost of fuel.
- Day 2 with No Change in FCA Tariff: Customers are charged $51.50/MWH as an energy purchase from the Midwest ISO.
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load, or $10.50/MWH (reflecting the differential in LMP prices due to marginal losses, as congestion costs are fully hedged)

Scenario 3[4]
Negative FTRs In Day Ahead Market.

In this example, Otter Tail bids its load demand in the Day-Ahead market and determines that it has 100 MW from Coyote available to offer for 24 hours in the Day Ahead market. Load is picked up at a price of $25/MWH (consisting of energy at $25/MWH and no congestion). The Coyote plant offer is accepted and is purchased by MISO at a price of $40/MWH ($25/MWH for energy and $15/MWH for congestion). The fuel cost for Coyote generation is $10/MWH. The Company holds FTRs for all 100 MW from Coyote for this day.

Resulting Charges:

- Otter Tail pays $25/MWH (for 100 MW*24) to the Midwest ISO.
- The Company incurs costs of $10/MWH for fuel.
- Otter Tail receives a payment of $40/MWH (for 100 MW*24) from the Midwest ISO for its generation.
- Otter Tail makes an FTR payment of $15/MWH (for 100 MW*24) to the Midwest ISO for holding a negative FTR.

Alternative FCA Outcomes for Customers:

- Today: Customers are charged $10 for cost of fuel.
- Day 2 with No Change in FCA Tariff: Customers are charged $25/MWH for the energy purchased from the Midwest ISO.
  (Assumes that generator revenues and FTR costs are not eligible for FCA accounting without a variance).
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load or $10/MWH (reflecting the that the FTRs were negative)

[4] In order to simplify the transactions, Scenario 3 and 5 do not address the costs associated with marginal losses or Marginal Loss Compensation revenues.

Scenario 4
Bilateral Purchase

This example involves a long-term bilateral purchase of 50 MW for 16 hours at a pre-established contract price of $35/MWh. Assume the Day Ahead market at the bilateral agreement's injection point clears at $25/MWH (inclusive of energy at $23/MWH, $0/MWH for congestion, and $2/MWH for losses). Also, assume that the Day Ahead market for load clears at $66/MWH (consisting of energy at $23/MWH,, congestion of $40/MWH, and $3/MWH for losses). Otter Tail holds 50 MW of FTRs for all 16 hours on this long-term purchase.

Resulting Charges:

- Otter Tail pays the counterparty to the bilateral agreement $35/MWH for the energy delivered.
- Otter Tail pays $66/MWH (for 50 MW*16 hours) to the Midwest ISO.
- The Company is paid $25/MWH for the LMP price at the injection point.
- Otter Tail receives a payment of $40/MWH (for 50 MW*16 hours) from the Midwest ISO for the value of its FTRs.

Alternative FCA Outcomes for Customers:

- Today: Customers are charged $35/MWH for the energy cost. The Midwest ISO Day 1 tariff requires the payment of physical losses—meaning we will need to purchase more than 50MW from the counterparty to receive 50MW at the OTP load. These additional MWh result in higher purchased energy costs (and causing the effective cost to be above $35/MWH) that flow through the FCA.
- Day 2 with No Change in FCA Tariff: Customers are charged $66/MWH for energy (assuming that if the variance in not approved, only the final purchase will flow through the FCA).
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues (including FTR revenues) associated with serving native load or $36/MWH.

ATTACHMENT B

Market Settlement Calculations
Guide Overview (MISO Business Practice Manual)

Day-Ahead Charge Types

Day-Ahead Asset Energy Amount

The Day-Ahead Asset Energy Amount represents an Asset Owner's total Day-Ahead net energy cost (or credit) associated with their asset related Commercial Nodes for an Operating Day. The Day-Ahead Asset Energy Amount is the net energy costs for an Asset Owner from their Assets and transactions at their Assets. The hourly charge or credit is a result of the net energy volume the Asset Owner scheduled at the asset multiplied by the LMP for that node. The hourly amounts are summed to determine a daily total. Virtual Schedule energy obligations and their charge/credit are calculated separately from this Charge Type.

There is only one Day-Ahead Asset Schedule per asset. The Day-Ahead Asset Schedule is the direct result of the Market Participant providing bids and offers into the Day-Ahead Energy Market that get lifted by the Midwest ISO. Market Participants can only submit bids and offers for their own assets.

Day-Ahead Financial Bilateral Transaction Congestion Amount

The Day-Ahead Financial Bilateral Transaction Congestion Amount represents an Asset Owner's total Financial Bilateral Transaction congestion costs and Carve-Out Grandfathered Agreement Transaction congestion costs for an Operating Day. The amount is calculated hourly by Asset Owner for every transaction where they are buying and/or selling and then is summed to a daily total. Since transaction congestion cost is the difference between two Commercial Nodes' congestion costs multiplied by the transaction volume, this amount can result in a charge or a credit depending upon the Commercial Nodes being settled. Day-Ahead Financial Bilateral Transaction Congestion Amount is calculated on Financial Bilateral Transactions (GFAOB and IBS transaction types) and Carve-Out Grandfathered Agreement Transactions.

Day-Ahead Financial Bilateral Transaction Loss Amount

The Day-Ahead Financial Bilateral Transaction Loss Amount represents an Asset Owner's total Financial Bilateral Transaction loss costs and Carve-Out Grandfathered Agreement Transaction loss costs for an Operating Day. The amount is calculated hourly for each transaction buyer and seller and summed by Asset Owner into a daily total. Since transaction loss costs are the difference between two Commercial Nodes loss costs multiplied by the transaction volume, this amount can result in a charge or a credit depending upon the Commercial Nodes being settled. Day-Ahead Financial Bilateral Transaction Loss Amount is calculated on Financial Bilateral Transactions (GFAOB and IBS transaction types) and Carve-Out Grandfathered Agreement Transactions.

Day-Ahead Market Administration Amount

The Day-Ahead Market Administration Amount in conjunction with the Real-Time Market Administration Amount, collectively referred to as tariff Schedule 17, are designed to recover the cost of operating the Day-Ahead and Real-Time Energy Markets. The Day-Ahead and Real-Time Market Administration Amounts are charged separately.

The Day-Ahead Market Administration Amount consists of a charge on transactions and a charge on market participation.

The transactional charge applies to Day-Ahead Virtual Bid and Offer Schedules only. A transaction is defined as a single bid or offer by hour by Asset Owner. On an hourly basis by Asset Owner, the number of transactions are counted and multiplied by the Administration Transaction Rate and added to the hourly charge calculated for hourly market participation.

For each Asset Owner for an Operating Day, Market Settlements assesses an administration charge on the Asset Owner's participation in the Day-Ahead Energy Market. The Asset Owner's Day-Ahead Energy Market participation volume is calculated at each Commercial Node for each hour and summed for the entire Operating Day. The resulting daily market participation volume is multiplied by the hourly Energy Markets Administration Rate. An Asset Owner's Day-Ahead hourly participation volume at a Commercial Node is based on the total directional energy volume into and out of the Commercial Node, by the Asset Owner.

Day-Ahead Non-Asset Energy Amount

The Day-Ahead Non-Asset Energy Amount represents an Asset Owner's daily Day-Ahead net energy cost (or credit) related to Commercial Nodes where the Asset Owner does not own assets for that Operating Day. This Day-Ahead Non-Asset Energy Amount is calculated hourly for each Asset Owner at each Commercial Node where the Asset Owner does not own generation, Load Zone, or Demand Response Resources (DRR). The Asset Owner's hourly energy obligation volume at each Commercial Node is calculated, multiplied by the LMP for the Commercial Node, and is summed into an Operating Day amount. Virtual Schedule energy obligations and their charge/credit are calculated separately from this Charge Type.

Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements

The Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of all congestion charges and credits paid in the Day-Ahead Financial Bilateral Transaction Congestion Amount charge type related to Carve-Out Grandfathered Agreements Transactions. The rebate amount is calculated hourly by Asset Owner for every valid Carve-Out Grandfathered Agreement Transaction where they are buying and/or selling and then is summed to a daily total. Since the original congestion amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements

The Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of all loss charges and credits paid in the Day-Ahead Financial Bilateral Transaction Loss Amount charge type related to Carve-Out Grandfathered Agreements Transactions. The rebate amount is calculated hourly by Asset Owner for every valid Carve-Out Grandfathered Agreement Transaction where they are buying and/or selling and then is summed to a daily total. Since the original losses amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Day-Ahead Congestion Rebate on Option B Grandfathered Agreements

The Day-Ahead Congestion Rebate on Option B Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of all congestion charges and credits paid in the Day-Ahead Financial Bilateral Transaction Congestion Amount charge type related to Option B Grandfathered Agreements Financial Bilateral Transactions. The rebate amount is calculated hourly by Asset Owner for every valid Option B Grandfathered Agreement Financial Bilateral Transaction where they are buying and/or selling and then is summed to a daily total. Since the original congestion amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Day-Ahead Losses Rebate on Option B Grandfathered Agreements

The Day-Ahead Losses Rebate on Option B Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of the difference between Marginal Losses and System Losses paid in the Day-Ahead Financial Bilateral Transaction Loss Amount charge type related to Option B Grandfathered Agreements Financial Bilateral Transactions. All valid Option B Grandfathered Agreement Financial Bilateral Transactions are assessed the full loss charge or credit per the Day-Ahead Financial Bilateral Transaction Loss Amount and receive a rebate of the difference between Marginal Losses and System Average Losses. The rebate amount is calculated hourly by Asset Owner for every valid Option B Grandfathered Agreement Financial Bilateral Transaction where they are buying and/or selling and then is summed to a daily total. Since the original loss amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Day-Ahead Revenue Sufficiency Guarantee Distribution Amount

Generation Resources that are committed by the Midwest ISO and scheduled in the Day-Ahead Energy Market are guaranteed cost recovery of their start-up costs, no load costs, and energy offer. Startup, no load, and energy offer are collectively referred to as production costs. On an hourly basis, the Day-Ahead Real-Time System (DART) determines whether a generation Resource has met the eligibility requirements to have its production costs guaranteed and what those production costs consist of from the asset's Day-Ahead submitted offer. The Day-Ahead settlement calculation compares whether the asset's energy value for all the eligible hours for the Operating Day exceeds the production costs for those same hours. If the total daily energy value is less than the total daily production cost amount, the difference is credited to the Asset Owner as a Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount.

Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount

Generation Resources that are committed by the Midwest ISO and scheduled in the Day-Ahead Energy Market are guaranteed cost recovery of their start-up costs, no load costs, and energy offer. Startup, no load, and energy offer are collectively referred to as production costs. On an hourly basis, the Day-Ahead Real-Time System (DART) determines whether a generation Resource has met the eligibility requirements to have their production costs guaranteed and what those production costs consist of from the asset's Day-Ahead submitted offer. The Day-Ahead settlement calculation compares whether the asset's energy value for all the eligible hours for the Operating Day exceeds the production costs for those same hours. The asset's energy value is calculated without regard to Financial Bilateral Transactions. If the total daily energy value is less than the total daily production cost amount, the difference is credited to the Asset Owner as a Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount.

Day-Ahead Virtual Energy Amount

The Day-Ahead Virtual Energy Amount represents an Asset Owner's total Day-Ahead net energy cost (or credit) associated with all their struck virtual bids and offers. The Day-Ahead Virtual Amount is calculated hourly for each Asset Owner by Commercial Node and is summed to determine a daily total. The hourly amount by Commercial Node is the net Day-Ahead Struck Virtual Bid & Offer volume multiplied by the associated LMP for the Commercial Node.

Financial Transmission Rights Charge Types

Financial Transmission Rights Hourly Allocation Amount

Market Settlement of Financial Transmission Rights (FTR) Hourly Allocation Amount is calculated for each FTR and summed into a daily total per Asset Owner. The FTR is a financial instrument that entitles the holder to receive compensation, or possible pay charge depending on the type of FTR, for congestion along an energy flow path. This instrument can be used to help hedge Day-Ahead congestion costs.

Financial Transmission Rights Market Administration Amount

The Financial Transmission Rights Market Administration Amount, referred to as tariff Schedule 16, recovers the cost of operating the Financial Transmission Rights Markets from Asset Owners. A flat rate administration charge is assessed per megawatt of FTR Profile Volume and per megawatt of scheduled, validated Grandfathered Agreement Financial Bilateral Transaction volume. The charge is summed by Asset Owner for the Operating Day. The administration charge rate is subject to change based on costs incurred by Midwest ISO.

Financial Transmission Rights Monthly Allocation Amount

Financial Transmission Rights (FTR) Monthly Allocation Amount is the distribution of excess congestion dollars collected during a calendar month, but not allocated in the FTR Hourly Revenue allocation process, to FTR holders that did not receive their full hourly credit revenue allocation. The excess congestion funds are distributed to all Asset Owners based on the amount of FTR credits not yet received for the calendar month. Midwest ISO held FTRs for Option B and Carve-Out Grandfathered Agreements are exempt from the monthly revenue allocation process.

Financial Transmission Rights Transaction Amount

The Financial Transmission Rights Transaction Amount is used to: 1) settle and invoice FTR purchases and sales, and 2) facilitate dollar exchanges between a host utility holding FTR Auction Revenue Rights and Asset Owners with retail choice Load obligations.

Market Participants may buy or sell Financial Transmission Rights (FTR) through FTR auctions. Records of purchases and sales of FTRs are simply passed from the FTR system to Market Settlements where purchases and sales are netted into a daily settlement value, and then passed to the Financial System for inclusion on Invoices. FTR Transactions are not resettled, they are assumed to be final when posted to Market Settlements; any change to the sale price of an FTR purchased or sold is conveyed to Market Settlements as an adjustment.

Financial Transmission Rights Yearly Allocation Amount

Financial Transmission Rights (FTR) Yearly Allocation Amount is a distribution of excess congestion funds from prior calendar years to FTR holders during the prior year that did not receive their full-targeted credit revenue allocation. The excess congestion funds are distributed on a prorated basis to all Asset Owners based on the amount of FTR credit shortfall each has remaining after the hourly and monthly revenue allocation processes for the previous calendar year. Midwest ISO held FTRs for Option B and Carve-Out Grandfathered Agreements are exempt from the yearly revenue allocation process.

Real-Time Charge Types

Real-Time Energy Asset Amount

The Real-Time Asset Energy Amount represents an Asset Owner's total Real-Time net energy cost (or credit) associated with their asset related Commercial Nodes for an Operating Day. The Real-Time Asset Energy Amount is the net energy costs for an Asset Owner from their Assets and transactions at their Assets. The hourly charge or credit is a result of the net energy volume for the Asset Owner at the asset multiplied by the Locational Marginal Price (LMP) for that node. The hourly amounts are summed to determine a daily total. Backed out Day-Ahead Virtual Schedule energy obligations are calculated separately from this Charge Type.

The Real-Time Asset Energy Amount represents an Asset Owner's total Real-Time net energy cost (or credit) associated with their asset related Commercial Nodes for an Operating Day. The Real-Time Asset Energy Amount is calculated hourly for each Asset Owner at their generation, Load Zone, and Demand Response Resource ("DRR") Commercial Nodes and includes applicable Financial Bilateral Transactions transacted by the Asset Owner at those Commercial Nodes.

Real-Time Distribution of Losses Amount

Real-Time Distribution of Losses Amount is the charge type that distributes surplus collected losses to Load Zone Asset Owners. This charge type is calculated hourly. The charge type has three main calculation routines: 1) the determination of the marginal loss surplus to be distributed, 2) the allocation of the surplus into loss pools, and 3) the distribution of the loss pools to each Asset Owner within each loss pool.

Real-Time Financial Bilateral Transaction Congestion Amount

The Real-Time Financial Bilateral Transaction Congestion Amount represents an Asset Owner's total Real-Time Financial Bilateral Transaction congestion costs f and Carve-Out Grandfathered Agreement Transaction congestion costs or an Operating Day. The Real-Time Financial Bilateral

Transaction Congestion Amount is calculated hourly for each buyer and seller of a Financial Bilateral Transaction with the charge amount summed by Asset Owner into a daily total.

Real-Time Financial Bilateral Transaction Loss Amount

The Real-Time Financial Bilateral Transaction Loss Amount represents an Asset Owner's total Real-Time Financial Bilateral Transaction loss costs and Carve-Out Grandfathered Agreement Transaction congestion costs for an Operating Day. The Real-Time Financial Bilateral Transaction Loss Amount is calculated hourly for each buyer and seller and summed by Asset Owner into a daily total.

Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements

The Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of all congestion charges and credits paid in the Real-Time Financial Bilateral Transaction Congestion Amount Charge Type to Carve-Out Grandfathered Agreements Transactions. The rebate amount is calculated hourly by Asset Owner for every valid Carve-Out Grandfathered Agreement Transaction where they are buying and/or selling and then is summed to a daily total. Since the original congestion amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Real-Time Losses Rebate on Carve-Out Grandfathered Agreements

The Real-Time Losses Rebate on Carve-Out Grandfathered Agreements Amount represents an Asset Owner's total Operating Day rebate of all loss charges and credits paid in the Real-Time Financial Bilateral Transaction Loss Amount charge type related to Carve-Out Grandfathered Agreements Transactions. The rebate amount is calculated hourly by Asset Owner for every valid Carve-Out Grandfathered Agreement Transaction where they are buying and/or selling and then is summed to a daily total. Since the original losses amount can be a charge or credit, likewise the rebate can be a charge or credit depending upon the Commercial Nodes that are being settled.

Real-Time Market Administration Amount

The Real-Time Market Administration Amount in conjunction with the Day-Ahead Market Administration Amount, collectively referred to as tariff Schedule 17, is designed to recover the cost of operating the Day-Ahead and Real-Time Energy Markets. The Day-Ahead and Real-Time Market Administration Amounts are charged separately.

For each Asset Owner for an Operating Day, Market Settlements assesses an administration charge on the Asset Owner's participation in the Real-Time Energy Market. The Asset Owner's

Real-Time Energy Market participation volume is calculated at each Commercial Node for each hour and summed for the entire Operating Day. The resulting daily market participation volume is multiplied by the hourly Energy Markets Administration Rate. An Asset Owner's Real-Time hourly participation volume at a Commercial Node is based on the total directional energy volume, into and out of the Commercial Node, by the Asset Owner.

Real-Time Miscellaneous Amount

The Real-Time Miscellaneous Amount charge type is a mechanism that allows the Midwest ISO to issue charges and/or credits based on specific requirements to either one Asset Owner or to the entire market. The Midwest ISO follows a strict internal approved procedure process prior to initiating this charge. This charge type can be used for charges or credits ordered by the Independent Market Monitor. This specific charge type facilitates the following charges and/or credits:

Real-Time Net Inadvertent Distribution

Real-Time Net Inadvertent Distribution is the daily allocation to Asset Owners of any energy dollars that result from the Midwest ISO Balancing Authority Net Inadvertent for an Operating Day. On an hourly basis each Balancing Authority is tasked with balancing their energy generation supply, their load and their Net Scheduled Interchange. The difference between the Net Scheduled Interchange and the Net Actual Interchange is Net Inadvertent. The hourly energy cost of the Net Inadvertent is calculated by averaging the LMP from all generators in a Control Area times the volume of the inadvertent for that same hour plus the cost of any impact resulting from seams agreements that the Midwest ISO has with other Control Areas. The dollar impact for all hours in an Operating Day for all the Midwest ISO Balancing Authorities is summed and is allocated to Asset Owners based on the Asset Owner's participation in the Day-Ahead and Real-Time Energy Markets for the Operating Day.

Real-Time Non-Asset Energy Amount

The Real-Time Non-Asset Energy Amount represents an Asset Owner's daily Real-Time net energy cost (or credit) related to Commercial Nodes where the Asset Owner does not own generation, load, or Demand Response Resource assets for the Operating Day. The amount is calculated hourly for each Asset Owner at each Commercial Node where the Asset Owner does not own generation or load assets. The Asset Owner's hourly non-asset energy volume at each Commercial Node is multiplied by the LMP for the node and is summed into an Operating Day amount.

Real-Time Revenue Neutrality Uplift Amount

Real-Time Revenue Neutrality Uplift Amount is a charge type set up as a revenue distribution balancing mechanism for charges and credits that have no other distribution method to Asset

Owners. On an hourly basis, all charges and credits that have no other distribution method are summed, and the subsequent total charge or credit for the hour is distributed to Asset Owners based on their Load Ratio Share (LRS). An Asset Owner's Load Ratio Share is determined by summing the volumes of the Asset Owner's assets that are consuming energy (acting as load) for an hour and dividing the result by the sum of all Asset Owner assets that are consuming energy during the same hour. The hourly charges and credits are summed into a daily Real-Time Revenue Neutrality Adjustment Amount.

Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount

Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount credited to Asset Owners is funded hourly by the Midwest ISO primarily using the Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount charge type.

The Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount credits are the direct result of having insufficient generation Resources cleared in the Day-Ahead Energy Market to meet the expected requirements of the Real-Time Energy Market. The Day-Ahead process only clears generation to cover the Load requirements bid into the Day-Ahead Energy Market. As such, the Reliability Assessment Commitment process commits additional generation resources to meet the anticipated additional load expected in the Real-Time Energy Market. Some of the causes for additional Real-Time load are: 1) load not bid into the Day-Ahead Energy Market, 2) Virtual Offers cleared in the Day-Ahead Energy Market, 3) generation resources not showing up as expected in the Real-Time Energy Market, and 4) changes in Real-Time Physical Bilateral Transactions.

Real-Time Revenue Sufficiency Make Whole Payment Amount

Generation Resources that meet eligibility requirements that are committed by the Midwest ISO in the Reliability Assessment and Commitment (RAC) process for the Real-Time Energy Market are guaranteed cost recovery of their start-up costs, no load costs, and energy offer in this charge type. Startup, no load, and energy offer are collectively referred to as production costs.

The Midwest ISO performs the RAC process to ensure that sufficient Resources are available and on-line to meet Load Forecast and Capacity requirements projected for each Hour of the Operating Day. After the Day-Ahead Energy Market is cleared, the Midwest ISO performs the Real-Time related RAC process and may commit additional Resources beyond those cleared in the Day-Ahead Energy Market to meet the forecasted needs within the Midwest ISO. The RAC process employs a Security Constrained Unit Commitment algorithm and is performed as necessary prior to, and throughout, the Operating Day.

Real-Time Uninstructed Deviation Amount

Real-Time Uninstructed Deviation Amount is charged to non-exempted generators that do not follow the Midwest ISO Real-Time Energy Market dispatch signal. In the Real-Time Energy Market, the Midwest ISO sends a dispatch signal to each generator identifying the expected megawatt output that it is expected to be generating in the next five minutes. Over the course of the hour these dispatch signals are integrated into an hourly dispatch set point used for settlement. The generator's actual metered performance is measured against the dispatch set point and when the deviation exceeds the tariff specified threshold, then uninstructed deviation charges are incurred by the Asset Owner for that hour.

Real-Time Virtual Energy Amount

The Real-Time Virtual Energy Amount represents an Asset Owner's total Real-Time net cost (or credit) associated with the Asset Owner's Day-Ahead net virtual schedules being backed out, or unwound, in the Real-Time Energy Market. The Real-Time virtual schedule volume is equal to the Day-Ahead volume multiplied by minus one. The Real-Time Virtual Energy Amount is calculated hourly for all schedules and summed into a daily total per Asset Owner.

Additional Terms

Locational Marginal Price (LMP)
The market clearing price for energy at a given location that is equal to the cost of supplying the next increment of load at that location

Day-Ahead Energy Market
Energy services that are bought and sold on the prior to the day operation using the Day-Ahead LMP for settlements

Real-Time Energy Market
Energy services that are bought and sold on the prior to the day operation using the Real-Time LMP for settlements

Financial Transmission Rights (FTR)
Tradable Financial instruments that allow Market Participants to hedge against congestion in the Day-Ahead Market

Financial Bilateral Transaction
An agreement between a buyer and a seller for the transfer of energy between commercial pricing nodes (CPNode) at the source and sink points representing the financial flow of energy.
Financial Schedules are subject to congestion and loss charges within MISO.

Physical Bilateral Transaction
An agreement between a buyer and seller for transfer of energy between a commercial pricing nodes and a Generation Control Area (outside of MISO) or Load Control Area (outside of MISO) at the source and sink point representing the physical flow of energy

FUEL ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatt-hour (rounded to the nearest 0.001¢) that the average cost of fuel is above or below 1.5460¢ per kilowatt-hour. The average cost of fuel per kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent three-month period as follows:

Energy costs from actual months 1, 2 and 3 plus unrecovered (or less over recovered) prior cumulative energy costs plus (or minus) the carrying charge, divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2 and 3 equals the cost of energy amount.

The applicable adjustment will be applied month to month on a uniform billing cycle to each customer's bill at the earliest practical date following the three-month period. The cost of fuel shall be determined as follows:

1. The expense of fossil and other fuels, including but not limited to, biomass, wood, refuse-derived fuel (RDF), and tire-derived fuel (TDF), as recorded in Account 151 of the FERC's Uniform System of Accounts for Public Utilities and Licensees, used in the Company's generating plants.

2. The utility's share of the expense of fossil fuel, as recorded in Account 151, used in jointly-owned or leased plants.

3. The net energy cost of energy purchases when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges.

4. The net cost of energy purchases from any facility utilizing wind or other renewable energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis.

5. Renewable energy purchased for the TailWinds program is not included in the fuel clause adjustment calculation.

6. The actual identifiable fossil and nuclear fuel expense associated with energy purchased for reasons other than identified in 3 and 4 above.

7. Less the fossil fuel and other related costs recovered through intersystem sales, including the fuel costs and or renewal energy costs related to economy energy sales and other energy sold on an economic dispatch basis

Where, for any reason, billed system sales cannot be coordinated with fuel and other related costs, sales may be equated to the total of:

1. Net generation
2. Purchases and net interchange in, less
3. Intersystem sales, less
4. Losses on system retail sales

A carrying charge or credit will be included to determine the monthly fuel adjustment factor. The carrying charge or credit will be determined by applying one-twelfth (1/12) of the overall rate of return granted by the Commission in the most recent rate decision to the recorded deferred fuel cost balance of the latest fuel adjustment calculation.

FUEL ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatt-hour (rounded to the nearest 0.001¢) that the average cost of fuel is above or below 1.5460¢ per kilowatt-hour. The average cost of fuel per kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent three-month period as follows:

Energy costs from actual months 1, 2 and 3 plus unrecovered (or less over recovered) prior cumulative energy costs plus (or minus) the carrying charge, divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2 and 3 equals the cost of energy amount.

The applicable adjustment will be applied month to month on a uniform billing cycle to each customer's bill at the earliest practical date following the three-month period. The cost of fuel shall be determined as follows:

1. The expense of fossil and other fuels, including but not limited to, biomass, wood, refuse-derived fuel (RDF), and tire-derived fuel (TDF), as recorded in Account 151 of the FERC's Uniform System of Accounts for Public Utilities and Licensees, used in the Company's generating plants.

2. The utility's share of the expense of fossil fuel, as recorded in Account 151, used in jointly-owned or leased plants.

3. The net energy cost of energy purchases when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges.

4. The net cost of energy purchases from any facility utilizing wind or other renewable energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis.

5. Renewable energy purchased for the TailWinds program is not included in the fuel clause adjustment calculation.

6. Costs or revenues linked to the utility's load serving obligation, associated with participation in wholesale electric energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the energy markets. (N)

7. The actual identifiable fossil and nuclear fuel expense associated with energy purchased for reasons other than identified in 3 and 4 above. (L)

8. Less the fossil fuel and other related costs recovered through intersystem sales, including the fuel costs and or renewal energy costs related to economy energy sales and other energy sold on an economic dispatch basis. (L)

Where, for any reason, billed system sales cannot be coordinated with fuel and other related costs, sales may be equated to the total of:

1. Net generation
2. Purchases and net interchange in, less
3. Intersystem sales, less
4. Losses on system retail sales

A carrying charge or credit will be included to determine the monthly fuel adjustment factor. The carrying charge or credit will be determined by applying one-twelfth (1/12) of the overall rate of return granted by the Commission in the most recent rate decision to the recorded deferred fuel cost balance of the latest fuel adjustment calculation.

ATTACHMENT D

Report of Tariff Schedule Change

NAME OF UTILITY: Otter Tail Corporation d/b/a Otter Tail Power Company
ADDRESS: 215 S Cascade St
Fergus Falls, MN 56537

Section No.	Class of Service	New Sheet No.
3	Fuel Adjustment Clause M-60S	7th Revised Sheet No. 52

Change: Applicability
(State part of the tariff schedule affected by change, such as: Applicability, Rates, etc.)

Reason for change: Provide for the recovery of MISO Day 2 costs through the fuel cost adjustment.

Present Rates.. _______
Proposed Rates.. _______
Approximate annual reduction in revenue.. N/A
Approximate annual increase in revenue.. N/A

Points Affected	Estimated Number of Customers Whose Cost of Service will be:					
	Reduction		Increase		Unchanged	
	# of Customers	Amount in $	# of Customers	Amount in $	# of Customers	Amount in $
All	N/A	N/A	N/A	N/A	N/A	N/A

Include Statements of Facts, expert opinions, documents and exhibits supporting the change requested.

Received: ____________________

Otter Tail Power Company
(Reporting Utility)

By: ____________________
Executive Director

South Dakota
Public Utilities Commission

By: Bernadeen Brutlag
Manager, Regulatory Services

(Name and Title)

SD-20:10:13:26