

DIVIDER

STATE OF NORTH DAKOTA
INFORMATION TECHNOLOGY DEPARTMENT
SFN 2053 (4-2002)

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DESCRIPTION

PU-05-131
Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff
Filed 2/28/2005 Closed 3/10/2008 05

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

RECEIVED

MAR 10 2008

PUBLIC SERVICE COMMISSION

VIA Electronic Mail and First Class Mail

March 10, 2008



Ms. Ilona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505

SUBJECT: Correction of Typographical Error in Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY's (Otter Tail) Cost of Energy Adjustment Clause Tariff (Sheet 98, Rate Designation M-60N)

Dear Ms. Jeffcoat-Sacco:

Otter Tail Corporation d/b/a Otter Tail Power Company encloses the Cost of Energy Adjustment Clause Tariff (Sheet 98, Rate Designation M-60N), which was changed for correction of a typographical error and was effective April 20, 2007.

The typographical error was addressed in a filing sent on March 21, 2007. The only change was the removal of "5" from description of the months used for the cost of energy adjustment rate calculation, and inserting "4".

The change eliminated "5" from the description of the months used for the cost of energy adjustment rate calculation. This is a typographical error and has not governed Otter Tail's calculation of its cost of energy rate. Otter Tail has been calculating the cost of energy rate in compliance with North Dakota Administrative Rule 69-09-02-39.

Enclosed are an original and seven copies of Otter Tail Power Company's Tariff sheet 98 (volume1), rate designation M-60N, page 1 of 1. An electronic copy of the filing is being sent via email to you at: ijis@nd.gov, and to ndpsc@nd.gov and Jerry Lien, JLein@nd.gov.

If you have any questions regarding this matter, please contact me at (218) 739-8896 or dross@optpco.com.

Yours very truly,

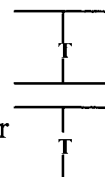
Dave Ross
Tariff Specialist
Regulatory Services
Enclosure

51 PU-05-131 Filed 3/10/2008 Pages 2
Corrected Tariff Sheet 98

COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, and 4 equals the cost of energy adjustment for month 6.



The applicable adjustment will be applied effective on any billing dated on or after the first day of each calendar month. The average cost of energy shall be determined as follows:

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants. Energy from the Company's hydro generating plants shall be included at zero cost.
2. The energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges. This includes but is not limited to net costs 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.
3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. Less the fuel related costs recovered through intersystem sales.

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff**

Case No. PU-05-131

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Paula Kent deposes and says that

she is over the age of 18 years and not a party to this action and, on the **9th day of August, 2007**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of

**Motion
Order
Settlement Agreement**

The envelopes were addressed as follows.

Bernadeen Brutlag
Manager - Regulatory Services
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496
Cert. No. 7007 0710 0001 5988 1644

Thomas D. Kelsch
Counsel for North Dakota OTP Large
Industrial Energy Group
P. O. Box 1266
Mandan ND 58554-7266
Cert. No. 7007 0710 0001 5988 1620

Bruce Gerhardson
Associate General Counsel
Otter Tail Corporation
215 S Cascade St.
Fergus Falls MN 56538-0496
Cert. No. 7007 0710 0001 5988 1637

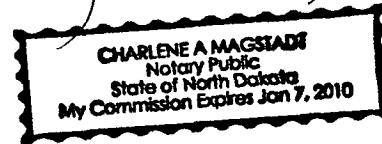
Each address shown is the respective addressee's last reasonably ascertainable post office address.

Paula Kent

Subscribed and sworn to before me
this **9th** day of **August, 2007**.

Charlene A. Magstad
Notary Public

SEAL



APPROVED

DATE: 8-8-07
843

MOTION

August 8, 2007

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

I move the Commission adopt the Order Adopting Settlement in the tariff filing of Otter Tail Corporation d/b/a Otter Tail Power Company for fuel cost adjustment recovery of Midwest ISO Day-2 energy market costs, Case Nos. PU-05-131.

JRL

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

ORDER ADOPTING SETTLEMENT

August 8, 2007

On March 1, 2005, Otter Tail Corporation, d/b/a Otter Tail Power Company (Otter Tail) filed revisions to its Fuel Clause Adjustment (FCA) tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO regional wholesale Day 2 electric energy market.

On April 6, 2005 the Commission issued an Interim Order temporarily authorizing the recovery of costs from the Midwest ISO's new Day 2 energy market through Otter Tail's fuel cost adjustment (FCA) billing mechanism. The Commission required that each of the 32 Midwest ISO billing line items be recorded as costs of purchased energy in separate sub-accounts under FERC Account 555 Purchased Power. The Commission found that sufficient Day 2 operational experience and market maturity would be necessary before adopting any permanent accounting treatment. The Commission ordered that FCA recovery of Day 2 costs be authorized on an interim basis and that the recovery of net Day 2 costs be subject to refund plus interest if the Commission ultimately ordered different accounting practices.

On December 8, 2006, an informal hearing was held during which Commission staff presented results of its investigation regarding the reasonableness of Otter Tail's Day 2 market participation and the resulting costs. Based on data from initial Day 2 market operations, staff concluded that Otter Tail had not relied heavily on net Day 2 market purchases and the resulting market costs had not been an overly significant portion of Otter Tail's energy costs.

On January 12, 2007, a Petition to Intervene was filed by the North Dakota OTP Large Industrial Energy Group. The Large Industrial Energy Group is made up of several of Otter Tail's largest industrial customers in North Dakota including Northern Sun/ADM, Cargill Incorporated, Goodrich, Bobcat, Imation Corporation and Cavendish Farms. The petition was granted by the Commission on January 24, 2007.

On March 21, 2007 the Commission issued a Notice of Hearing, scheduling a public hearing for May 22, 2007. The notice identified the following issues to be considered:

1. Whether the interim accounting treatment authorized for recovery of Day 2 market costs is appropriate and should be continued or whether a different or modified accounting treatment should be required.

2. Whether a percentage of wholesale revenues derived from off system energy sales should be shared with retail customers.
3. Whether any amounts already collected should be refunded with interest.

On May 22, 2007, a public hearing was convened as scheduled. During the opening phases of the hearing the parties presented a proposed settlement agreement that would resolve all outstanding issues in this proceeding. The hearing was suspended pending consideration of the proposed settlement agreement.

On July 11, 2007, the Commission discussed the proposed settlement agreement with the parties and Commission staff during an informal hearing. Staff recommended the Commission approve the settlement agreement with clarification that Otter Tail still bears the burden of showing that any deferred cost amortization should be allowed in test year revenue requirements during its next general rate case. Staff was especially interested in whether Otter Tail's earnings during the deferral period, including earnings from asset and non-asset based intersystem sales, were sufficient such that those deferrals have already been recovered through other rates. As a result of discussions during the informal hearing, a revised and fully executed settlement agreement with minor clarifying language changes was filed on July 16, 2007


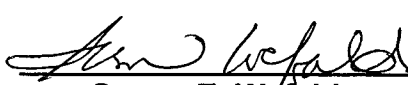
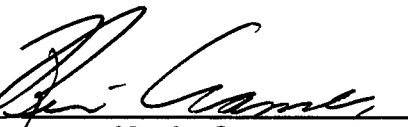
Having considered this matter, the Commission finds the revised settlement agreement is reasonable and should be approved. Therefore, the Commission issues the following:

Order

The Commission Orders:

1. The revised settlement agreement filed July 16, 2007, a copy of which is attached to and made a part of this Order, is approved.
2. Otter Tail is reminded that it still bears the burden of proof as to whether it is reasonable to include any amortization of deferred Day 2 market cost in rate case test year revenue requirements.

PUBLIC SERVICE COMMISSION

		
Tony Clark Commissioner	Susan E. Wefald President	Kevin Cramer Commissioner

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

In the Matter of Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY's
Application For Fuel Clause Adjustment Revision
for MISO Day 2 charges

Case No. PU-05-131

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 21st day of May, 2007 by and between the North Dakota Large Industrial Energy Group ("Large Industrial Energy Group") and Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail") (collectively the "Parties"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in fair and reasonable rates for Otter Tail's retail customers in North Dakota.

BACKGROUND

In its March 21, 2007 Notice of Hearing in this matter, the North Dakota Public Service Commission ("Commission") identified the following three issues as needing resolution in this proceeding:

1. Whether the interim accounting treatment authorized for recovery of Day 2 market costs is appropriate and should be continued or a different or modified accounting treatment should be required.
2. Whether a percentage of wholesale revenues derived from off system energy sales should be shared with retail customers.
3. Whether any amounts already collected should be refunded with interest.

The following Settlement provides recommendations to the Commission on each of these issues. The following terms are taken, with minor modifications needed to make them North Dakota specific, from the Joint Report and Recommendation adopted by the Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR

MISO DAY 2 COSTS. The adoption of these terms by the Commission was requested by Mr. Larry Schedin, witness on behalf of the Large Industrial Energy Group, and supported in part by the Mr. Peter Beithon, witness on behalf of Otter Tail.

PROCEDURAL HISTORY

On March 1, 2005, Otter Tail filed an Application for revisions in its Fuel Clause Adjustment (“FCA”) tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO (“MISO”) Day 2 regional wholesale electric energy market. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing new accounting procedures for interim fuel clause recovery of the net costs of energy purchased through the new market subject to refund with interest in the event the Commission ultimately ordered a different or modified accounting treatment that results in lower charges. On January 24, 2007 the Commission granted intervention to the Large Industrial Energy Group. On April 20, 2007 the Large Industrial Energy Group filed Direct Testimony, and on May 14, 2007, Otter Tail filed Reply Testimony.

Terms of Settlement Agreement

The Parties agree to, and recommend the Commission approve the following provisions.

1. Except as regards Schedules 16 and 17¹ costs, discussed below, Otter Tail may recover the charges imposed by the Midwest Independent Transmission System Operator, Inc., for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of Otter Tail’s FCA. from the period April 1, 2005 through a period of at least three years after the date of the Commission Order accepting the Settlement Agreement.
2. Otter Tail may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005. Otter Tail may continue deferring Schedule 16 and 17 costs without interest until the earlier of Otter Tail’s next electric rate case or March 1, 2009. By

¹ See Appendix A hereto for a description of MISO schedules 16 and 17

March 1, 2009, Otter Tail shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until Otter Tail has a rate case addressing its proposal for recovering the balance.

3. In its next rate case, Otter Tail may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. Otter Tail may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, Otter Tail may seek to recover Schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final Commission approval.
4. Otter Tail shall use reasonable efforts to refund through the FCA all Schedule 16 and 17 costs previously recovered through the FCA by February 1, 2008. This refund amount shall be included in the deferral balance. For purposes of OTP's fuel clause true-up calculations, the refunds for Schedule 16 and 17 costs shall be reflected in the calculations for the periods during which they are made. The refund of Schedule 16 and 17 costs shall not affect prior true-ups.
5. Virtual Energy transactions in the Day 2 market are subject to the following conditions:
 - A. Otter Tail may use virtual energy transactions to take positions 1) from the Day-Ahead to the Real-Time market or 2) from the Real-Time to the Day-Ahead market, but only as a strategy to reduce risk and/or minimize costs assigned to retail customers. Otter Tail shall not engage in virtual energy transactions that affect the FCA for speculative purposes.
 - B. Virtual energy transactions that affect the FCA shall be summarized on a monthly basis and be included as a component of the monthly fuel clause reports to the Commission.

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- C. Otter Tail shall restrict the use of virtual transactions that affect the FCA to 10% of total MWh subject to the FCA on a monthly basis with the understanding that the 10% threshold may be exceeded in any particular month, subject to the requirement that Otter Tail must explain the reasonableness of any deviation above the 10% threshold in its monthly fuel clause reporting. The 10% threshold does not apply to non-FCA virtual energy transactions (e.g. for non-asset based trading activities). The Commission may review and reset the 10% threshold as circumstances warrant.
6. Otter Tail shall adopt the following accounting practices:
- A. Recording each transaction to a separate sub-account of Accounts 447 and 555.
 - B. Recording to Account 555 on an aggregated basis any revenues and costs linked to Day 2 LMP, including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause.
 - C. Using net accounting for purchases and sales for owned generation facilities.
 - D. Continuing to use Accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they are accounted for today.
 - E. Continuing to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
 - F. Tracking in a separate sub-account each MISO charge and revenue.
 - G. Allocating all MISO Day 2 charges pursuant to the Minnesota Joint Report's Exhibit C, attached in revised form.

7. Otter Tail shall provide the following additional reporting requirements:

A. Otter Tail shall upon request and subject to a reasonable protective agreement in a form agreed to by Otter Tail and Large Industrial Energy Group shall supply the report it files in Minnesota which contains certain additional information regarding its plans with respect to acquiring fuel and purchased energy. The report must be provided within thirty days of receipt of the request and a signed protective agreement is in place. The Commission will have authority to establish the form of the protective order if the parties cannot agree.

- 1) Otter Tail shall include in its report an overview of its anticipated events and planned actions to address fuel clause costs, and the actions planned by Otter Tail to minimize or lower such costs whenever possible. Otter Tail shall provide a discussion of tools for managing fuel clause costs, including a) plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels, b) plans to hedge purchased energy costs (either through forward bilateral purchases or financial instruments), including how Otter Tail will plan for and cover fuel and energy risk during planned unit outages, and c) where deemed appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of FTRs in the MISO Day 2 Market.
- 2) Customers may petition to intervene and seek either a technical review or, pursuant to appropriate protective agreements, be allowed to conduct an audit of Otter Tail's fuel and energy costs to review the prudence of Otter Tail's actions in relation to the market.
- 3) Otter Tail shall provide and update a list of the network resources that it designates used to serve native load.

- B. To help customers manage their energy costs, Otter Tail shall provide large industrial customers who request the information and who sign a reasonable protective agreement in a form approved by Otter Tail and the Large Industrial Users, an annual FCA Forecast of the cost per MWh of fuel and purchased power costs for the next 12 months. This FCA Forecast shall include all fuel and energy costs associated with the operation of Otter Tail's system, in addition to projected MISO Day 2 costs and revenues. The FCA Forecast shall identify major changes that impact the stability of the forecast resulting from underlying changes in Otter Tail's cost inputs. The FCA Forecast shall also address projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Finally, Otter Tail shall explain the reasons for deviations in forecasts from actual costs in the previous year.
- C. Otter Tail shall prepare a summary of the information provided under paragraph B above, stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast. Otter Tail shall update its FCA Forecast whenever deviations from the current forecast are sufficiently material such that it requires a re-forecast for the next 12-month period. Otter Tail shall attempt to respond in a timely manner to questions from customers who have signed a protective agreement.
- D. Otter Tail shall meet with interested parties to discuss the FCA Forecast, its progress in achieving the FCA Forecast, and address any new proposals in the MISO Day 2 Market. Protective agreements governing disclosure of confidential information may be necessary.
- E. Otter Tail shall, upon request and subject to the above-described protective agreement, provide to the Large Industrial Users fuel and purchased energy forecasts for each monthly FCA filing in the same form as Otter Tail provides in Minnesota, which Otter Tail shall endeavor to provide three days prior to the first day of the FCA billing month. To the extent the monthly fuel and purchased

energy FCA Forecast exceeds the budget for that month set forth in the then current FCA Forecast by more than 10%, Otter Tail shall provide an explanation of the cause(s) of this change.

- F. In the event that Otter Tail's forecast of fuel and energy costs for a month deviates from actual fuel and energy costs by 15% or more, Otter Tail shall prepare a monthly deviation explanation quantifying the major reasons such as unit outages, congestion costs, weather, and fuel price changes. Otter Tail shall explain how it can control these costs, or the extent to which it is unable to control these costs.
 - G. Otter Tail shall use the monthly FCA reporting format as set forth in the Minnesota Joint Report's Exhibit D, attached in revised form (with minor variations permitted), listing each Day 2 charge type grouped into seven categories and providing cumulative data for the calendar year.
 - H. Otter Tail shall supplement its monthly fuel clause filing with information on significant events affecting that month's fuel clause costs.
8. Otter Tail shall address wholesale revenue margin sharing issues in its next rate case, which shall be filed no later than November 1, 2008, unless Otter Tail on or before that date makes a showing of good cause why a later filing is preferable, but in no event later than December 31, 2008. In its rate case filing, Otter Tail shall either propose a mechanism to credit asset-based wholesale margins through its fuel clause, like the mechanism and percentage approved for asset-based margins for Xcel Energy in its most recent Minnesota Rate Case, Docket No. E-002/GR-05-1428, or explain why such a mechanism should not be adopted. Interim rates shall be established using the same sharing mechanism proposed by Otter Tail for establishing final rates.
9. Otter Tail shall use its lowest cost generation or resource to serve its ratepayers.

10. Otter Tail shall challenge, both at the administrative level and through appeal if necessary, any FERC action that would require it to purchase energy to serve native load customers at LMP market clearing prices without the associated offset, as well as challenge any action that would preclude the utilities from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load as currently occurs under the MISO Day 2 tariff.
11. The approval for cost recovery as outlined in this Settlement Agreement shall terminate 60 days after the effective date of any FERC final decision and order having the effect of requiring Otter Tail to purchase energy to serve native load customers in whole or in part at LMP market clearing prices, action that would prevent Otter Tail from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load, or any other action preventing Otter Tail from using its lowest cost generation or resource to serve its native load ratepayers.

ADDITIONAL REQUEST BY LARGE ENERGY GROUP

The Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS, also opened an investigation and directed the Minnesota Department of Commerce (“Department”) by February 2009 to conduct a comprehensive review of the consequence of MISO Day 2 operations on Minnesota ratepayers and shall recommend changes as appropriate. All of the Minnesota utilities were required to provide relevant data to the Department in their AAA reports due September 1, 2008. The Large Energy Group requests that the Commission open a similar investigation in North Dakota, and Otter Tail has agreed not to object to such an investigation.

OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the

Company's next general rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The Company shall within 30 days of the Order approving the Settlement file amended tariffs as necessary to reflect the change in the recovery of Schedule 16 and 17 charges.

Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Counterparts

This Settlement Agreement may be executed in counterparts.

Dated this 12th day of July, 2007.

Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail")

By: Bruce Gerhardson by Michael D. Swaley
Bruce Gerhardson
Associate General Counsel

Dated this 13 day of July, 2007.

ND Large Industrial Energy Group

By: Thomas D. Kelsch
Thomas D. Kelsch

Description of Schedules 16 and 17 - Market Administration Charges

The costs of operating the Day Ahead, Real Time and FTR markets are known as MISO Schedule 16 and Schedule 17 expenses and as Miscellaneous expenses.

Schedule 16 Financial Transmission Rights Market Administration Amount

The Financial Transmission Rights Market Administration Amount, referred to as MISO Schedule 16, recovers the cost of MISO operating the FTR Markets. 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 (e.g., by utility) for the Operating Day. The Schedule 16 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Day-Ahead Market Administration Amount

The Day-Ahead Market Administration Amount in conjunction with the Real-Time Market Administration Amount, collectively referred to as MISO Schedule 17, recover the cost of MISO 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 in the Day Ahead Energy Market. 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 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 Utility'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 energy volume into

and out of the Commercial Node; in short, it is based on the summation of generation plus load volumes multiplied by the rate for Schedule 17. The Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Real-Time Market Administration Amount

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

For each utility for an Operating Day, Market Settlements assesses an administration charge on the Asset Owner's participation in the Real-Time Energy Market. The Utility'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; in short, it is based on the summation of generation plus load volumes, less those volumes which cleared the Day-Ahead market multiplied by the rate for Schedule 17. The Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

))
The following is Exhibit C from the June 22, 2006

Minnesota Joint Report on MISO Day 2

(as referred to in item 6.G. of the settlement agreement in Case PU-05-131)

**ATTACHED HERETO
IS
EXHIBIT C**

Cost Allocation

For illustration, we assume that a hypothetical utility had the following transactions in a given hour:

- 1) DA Load forecast of 1000MW. All load submitted to the DA market. The DA LMP at the load zone was \$30/MWh.
- 2) The company's only generator was sold DA. The unit is 800MW and the LMP was \$28/MWh. 700MW are assigned to retail and 100MW are assigned to Asset Sales. The company had a bilateral purchase from Manitoba Hydro to serve native load. The purchase was for 100MW, cleared in the DA market, and the LMP was \$26/MWh. This is a DA physical import.
- 3) The company made a 200MW DA bilateral purchase from another MISO member to serve native load. This is a DA Fin Sched at a company node. From the delivery point to the company's load zone, congestion was \$1/MWh and losses were \$2/MWh.
- 4) The company purchased 50MW bilaterally at the Minnesota Hub and sold it bilaterally at Energy Hub as a Trading Sale. The LMP at Energy was \$35/MWh and the LMP at Minnesota was \$31/MWh. The company was responsible for congestion and losses from Minnesota Hub to Energy Hub. Losses were \$3/MWh and congestion was \$1/MWh.

Notes:

DA refers to Day Ahead, RT refers to Real-Time
 None of the companies have Carve-Out GFA transactions
 Other Tail Power is the only company with Option B GFA transactions

No.	Charge Type	Native Load	Asset Sales	Trading (Non-Asset) Sales	Method
Day Ahead & Real Time Asset & Non-Asset Energy & Loss					
1	DA Asset Energy	DA Generation (LMP x MWh) + DA Load (LMP x MWh) + DA Fin Sched (LMP x MWh) (\$28/MWh x 700MWh) + (\$30/MWh x 100MWh) + (\$30/MWh x 200MWh) = \$4400 [1, 2, 4]	DA Generation (LMP x MWh) (\$28/MWh x 100MWh) = \$2800 [2]	DA Fin Sched (LMP x MWh) Not illustrated	Direct assignment using calculations not used
3	DA Fin Sched Losses	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$2/MWh x 200MWh = \$400 [4]	N/A	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$3/MWh x 50MWh = \$150 [5]	Direct assignment using calculations not used
5	DA Non-Asset Energy	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh) (\$26/MWh x 100MWh) = \$2600 [3]	N/A	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh) (\$35/MWh x 50MWh) + (\$35/MWh x 50MWh) = \$3500 [5]	Direct assignment using calculations not used
13	RT Asset Energy	Load Imbalance (LMP x MWh) + Generation Imbalance (LMP x MWh) + Residual Load (LMP x MWh) + RT Fin Sched when node belongs to Asset Owner (LMP x MWh)	Generation Imbalance (LMP x MWh)	RT Fin Sched when node belongs to Asset Owner (LMP x MWh)	Direct assignment using calculations not used
14	RT Distribution of Losses	All assigned to native load	N/A	N/A	Direct assignment using calculations not used
16	RT Fin Sched Losses	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	N/A	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	Direct assignment using calculations not used
22	RT Non-Asset Energy	RT Physical Schedule (LMP x MWh) + RT Fin Sched when node doesn't belong to Asset Owner (LMP x MWh)	N/A	RT Physical Schedule (LMP x MWh) + RT Fin Sched when node doesn't belong to Asset Owner (LMP x MWh)	Direct assignment using calculations not used
Virtual Energy					
12	DA Virtual Energy	DA Virtual (LMP x MWh)	N/A	DA Virtual (LMP x MWh)	Direct assignment using calculations not used
27	RT Virtual Energy	RT Virtual (LMP x MWh)	N/A	RT Virtual (LMP x MWh)	Direct assignment using calculations not used
Physical Schedules & RT					
4	DA Market Admin	[DA Generation (MWh) + DA Load (MWh) + DA Physical Schedules (MWh) + DA Virtual Schedule (MWh) + DA Fin Sched with node not belonging to Asset Owner (MWh)] x DA Admin Rate	DA Generation (MWh) x DA Admin Rate	[DA Fin Sched with node not belonging to Asset Owner (MWh) + DA Physical Schedule (MWh) + DA Virtual Schedule (MWh)] x DA Admin Rate	Direct assignment using calculations not used
19	RT Market Admin	[Load Imbalance (MWh) + Generation Imbalance (MWh) + RT Fin Sched when node doesn't belong to Asset Owner (MWh)] x RT Admin Rate	Generation Imbalance (MWh) x RT Admin Rate	[RT Physical Schedules (MWh) + RT Fin Sched when node doesn't belong to Asset Owner (MWh)] x RT Admin Rate	Direct assignment using calculations not used
29	FTR Market Admin	Held FTRs (MWh) x FTR Admin Rate	Held FTRs (MWh) x FTR Admin Rate	Held FTRs (MWh) x FTR Admin Rate	Direct assignment using calculations not used
Congestion & FTRs					
2	DA Fin Sched Congestion	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$1/MWh x 200MWh = \$200 [4]	N/A	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$1/MWh x 50MWh = \$50 [5]	Direct assignment using calculations not used
15	RT Fin Sched Congestion	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	N/A	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	Direct assignment using calculations not used
26	FTR Hourly Allocation	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁) when difference is positive] + FTR Payments (LMP ₂ - LMP ₁) when difference is negative	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁) when difference is positive] + FTR Payments (LMP ₂ - LMP ₁) when difference is negative	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁) when difference is positive] + FTR Payments (LMP ₂ - LMP ₁) when difference is negative	Direct assignment using calculations not used
30	FTR Monthly Allocation	FTR Hourly Allocation Receipts for the given month	FTR Hourly Allocation Receipts for the given month	FTR Hourly Allocation Receipts for the given month	Allocate using the quantities determined in the calculation
32	FTR Yearly Allocation	FTR Hourly Allocation Receipts for the given year	FTR Hourly Allocation Receipts for the given year	FTR Hourly Allocation Receipts for the given year	Allocate using the quantities determined in the calculation
31	FTR Transaction Amount	Manually Assigned	Manually Assigned	Manually Assigned	Direct assignment using calculations not used
RSG & Make Whole Payments					
10	DA RSG Distribution	DA Load (MWh) + DA Net Exports (MWh) + DA Virtual Purchases (MWh)	N/A	DA Net Exports (MWh) + DA Virtual Purchases (MWh)	Allocate using the quantities determined in the calculation
11	DA RSG Make Whole Payment	DA Committed Gen (MWh)	DA Committed Gen (MWh)	N/A	Allocate using the quantities determined in the calculation
24	RT RSG First Pass Distribution	Load Imbalance (MWh) + Generation Imbalance (MWh) + RT Net Imports and Exports (MWh)	Generation Imbalance (MWh)	RT Net Imports/Exports (MWh)	Allocate using the quantities determined in the calculation
25	RT RSG Make Whole Payment	N/A	All assigned to asset sales	N/A	Direct assignment using calculations not used
Revenue Neutrality Uplift					
23	RT RNJ	Metered Load (MWh) + Physical Exports (MWh)	N/A	Physical Exports (MWh)	Allocate using the quantities determined in the calculation
Other Charges					
20	RT Miscellaneous	Manually Assigned	Manually Assigned	Manually Assigned	Direct assignment using calculations not used
21	RT Net Inadvertent	All assigned to native load	N/A	N/A	Direct assignment using calculations not used
26	RT Unrestricted Deviation	Absolute Value of Generation Imbalance (MWh)	Absolute Value of Generation Imbalance (MWh)	N/A	Allocate using the quantities determined in the calculation
Grandfathered Charge Types					
8	DA Congestion Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
9	DA Loss Rebate on Option B GFAs (OTP only)	All assigned to native load	N/A	N/A	Direct assignment using calculations not used
9	DA Loss Rebate on Option B GFAs (OTP only)	All assigned to native load	N/A	N/A	Direct assignment using calculations not used
8	RT Congestion Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
8	RT Loss Rebate on Option B GFAs	N/A	N/A	N/A	N/A
Total RSG Day & RT Charges					

The following is Exhibit D from the June 22, 2006

Minnesota Joint Report on MISO Day 2

(as referred to in item 7.G. of the settlement agreement in Case PU-05-131)

**ATTACHED HERETO
IS
EXHIBIT D**

**Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce**

Fuel adjustment clause data for the billing month of: June-06

Line No.		March-06	April-06	Total
Cost of Fuel				
1	Company's Generating Stations (Account 151)	-	-	-
2	MISO Day 2 Charges (not Schedule 16 & 17) (Account 555)	-	-	-
2	Plus Fuel Costs of Purchased Energy (Account 555)	-	-	-
3	Less Fuel Cost Recovery Inter-System Sales (Account 447)	-	-	-
4	Total Cost of Fuel	-	-	-
KWh Sales				
5	Total Sales of Electricity	-	-	-
6	Less Inter-System Sales	-	-	-
7	Total kWh	-	-	-
8	Cost of Fuel per kWh (cents/kWh)			#DIV/0!
Fuel Adjustment per kWh				
9	Fuel Adjustment Clause #16 :			
	Fuel Cost			#DIV/0!
	Less Base			-
	Fuel Adjustment		¢ / kWh	
10	Fuel Adjustment Clause #17 :			
	Fuel Cost			-
	Less Base			-
	Fuel Adjustment		¢ / kWh	

**Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce**

Kilowatt-hour Information for the Billing Month of: April-06

Line No.		kWh Sales	
	Minnesota Jurisdiction - Retail Sales		
1	Subject to Fuel Clause #16	679,890,187	kWh
2	Subject to Fuel Clause #17*	442,873	kWh
3	Non-Fuel Clause Sales	48,190,317	kWh
4	Total	728,523,177	kWh
	Non-Minnesota Jurisdiction Sales		
5	Sales for Resale	306,943,052	kWh
6	Total Sales of Electricity	1,035,466,229	kWh
7	Less Inter-System Sales	251,276,959	kWh
8	Total kWh Sales	784,189,270	kWh

Notes:

- The June 2006 bills will be mailed between June 1, 2006 and July 5, 2006.
- A majority of the kWh usage to which the fuel clause adjustment rates on this form are applicable will occur during the calendar month of June 2006 for all customers on Company's Large Power Service rate. A majority of the kWh usage for all other retail customers will occur during the calendar month of May 2006.
- Fuel Adjustment Clause #17: Because the rates containing this adjustment are based on annual kWh use, the fuel adjustment per kilowatt-hour applicable for the June billing period applies for the entire annual period (June through May).

Prepared by:

Date: May 24, 2006

Patty Tolvonen
Senior Accounting Analyst

MINNESOTA POWER
MISO MONTHLY ALLOCATION

MONTH: Apr-06

Charge Type	Account Number	Total Apr-06	FAC			Non-FAC
			Rela ¹	Resale	Tota ¹	Other
Day Ahead Asset Energy Amount	4470-0000 or 5551-0000 or 5551-0050					
Day Ahead Non-Asset Energy Amount	5551-0027					
Day Ahead Virtual Energy Amount	5551-0030					
Real Time Asset Energy Amount	4470-0000 or 5551-0000 or 5551-0050					
Real Time Non-Asset Energy Amount	5551-0043					
Real Time Virtual Energy Amount	5551-0049					
Energy Total						
Day Ahead Market Administration Amount	5551-0020					
Day Ahead Financial Bilateral Transaction Congestion Amount	5551-0021					
Day Ahead Financial Bilateral Transaction Loss Amount	5551-0022					
Day Ahead Congestion Release on Carry-Out Grandfathered Agreements	5551-0023					
Day Ahead Losses Rebate on Carry-Out Grandfathered Agreements	5551-0024					
Day Ahead Congestion Release on Option B Grandfathered Agreements	5551-0025					
Day Ahead Losses Rebate on Option B Grandfathered Agreements	5551-0026					
Day Ahead Revenue Sufficiency Guarantee Distribution Amount	5551-0028					
Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	5551-0029					
Financial Transmission Rights Market Administration Amount	5551-0031					
Financial Transmission Rights Hourly Allocation Amount	5551-0032					
Financial Transmission Rights Monthly Allocation Amount	5551-0033					
Financial Transmission Rights Transaction Amount	5551-0034					
Financial Transmission Rights Yearly Allocation Amount	5551-0035					
Real Time Market Administration Amount	5551-0036					
Real Time Financial Bilateral Transaction Congestion Amount	5551-0037					
Real Time Financial Bilateral Transaction Loss Amount	5551-0038					
Real Time Congestion Release on Carry-Out Grandfathered Agreements	5551-0039					
Real Time Losses Rebate on Carry-Out Grandfathered Agreements	5551-0040					
Real Time Distribution of Losses Amount	6551-0041					
Real Time Miscellaneous Amount	5551-0042					
Real Time Net Inadvertent Distribution Amount	6551-0044					
Real Time Revenue Neutrality Uplift Amount	5551-0045					
Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	5551-0046					
Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	5551-0047					
Real Time Unstructured Deviation Amount	5551-0048					
Energy Charges Total						
Grand Total						

Monthly MISO Day 2 Charges - April - December 2005
 Total MP charges for the period

Charge Type Description	April 2005	May 2005	June 2005	July 2005	August 2005	September 2005	October 2005	Nov
1 Day Ahead Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
3 Day Ahead Financial Bilateral Transaction Loss	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
5 Day Ahead Non Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
13 Real Time Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
14 Real Time Distribution Losses	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
18 Real Time Financial Bilateral Loss	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
22 Real Time Non Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
12 Day Ahead Virtual Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
27 Real Time Virtual Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
4 Day Ahead Market Administration (Schedule 17)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
19 Real Time Market Administration (Schedule 17)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
29 Financial Transmission Rights Administration (Schedule 16)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
2 Day Ahead Financial Bilateral Transaction Congestion	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
15 Real Time Financial Bilateral Congestion	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
28 Financial Transmission Rights Hourly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
30 Financial Transmission Rights Monthly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
32 Financial Transmission Rights Yearly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
31 Financial Transmission Rights Transaction	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
10 Day Ahead Revenue Sufficiency Guarantee Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
11 Day Ahead Revenue Sufficiency Make Whole Payments	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
20 Real Time Miscellaneous	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
21 Real Time Net Inadvertent Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
23 Real Time Revenue Neutrality Uplift Amount	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
26 Real Time Unstructured Deviation Amount	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
8 Day Ahead Congestion Rebate on Option B-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
9 Day Ahead Loss Rebate on Option B-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
17 Real Time Congestion Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
16 Real Time Loss Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$

Note. A negative number indicates an amount due from MISO and a positive number indicates an amount due to MISO

Summary by charge type

**Minnesota Power
Energy Purchases and Sales
June 2005**

Purchases	% MWh	MWh	Cost		
Generation	-	-	-		
Short Term Bilaterals	-	-	-		
Long Term Bilaterals	-	-	-		
MISO	-	-	-		
Total Purchases	-	-	-		
Sales	% MWh	MWh	Fuel Cost	Billing	
Short Term Bilaterals	-	-	-	-	-
Long Term Bilaterals	-	-	-	-	-
MISO	-	-	-	-	-
Retail Non-Firm	-	-	-	-	-
FAC Retail	-	-	-	-	-
FAC FERC Jurisdictional	-	-	-	-	-
Total Sales	-	-	-	-	-
Difference ¹		-			

Kelsch Kelsch Ruff & Kranda

C F Kelsch
1890-1987

Attorneys at Law
Mandan, North Dakota

William C Kelsch
Retired

THOMAS F KELSCH
ARLEN M RUFF, P C
THOMAS D KELSCH, P C
TODD D KRANDA, P C *
WILLIAM J DELMORE
DANIEL NAGLE

*Also Licensed in Minnesota

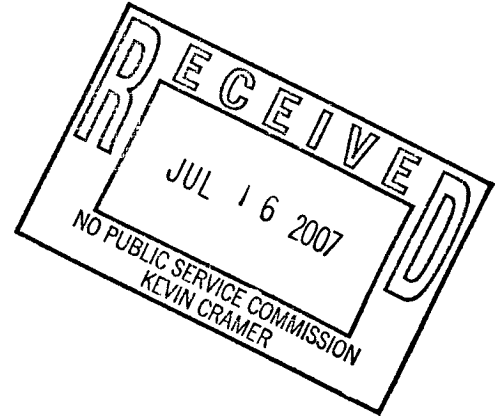
 MERITAS LAW FIRMS WORLDWIDE

103 Collins Avenue
P O Box 1266
Mandan, ND 58554-7266
Phone (701) 663-9818
1-888-663-9818
Fax (701) 663-9810
Website www.kelschlaw.com

July 13, 2007

ILLONA JEFFCOAT-SACCO
ND PUBLIC SERVICE COMMISSION
600 E BOULEVARD AVE
BISMARCK ND 58505-0480

RE: Case No. PU-05-131
NDPSC
Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
Settlement Agreement w/attachments
Our File No. 12039

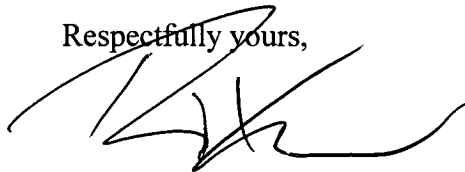


Dear Ms. Jeffcoat-Sacco:

I am enclosing an original and 7 copies of the fully-executed Settlement Agreement w/attachments in the above case no. PU-05-131 on behalf of ND OTP Large Industrial Energy Group and an Affidavit of Service.

If you have any questions, please give me a call.

Respectfully yours,



Thomas D. Kelsch

TDK:dr

Enclosures

cc: Eric Hoegger, Cargill, Incorporated (via email)
Steve Otto, Imation (via email)
Larry Schedin (via email)
Kavita Maini (via email)
Michael J. Bradley (via email & mail)
Bruce Gerhardson, Otter Tail Corporation
Allen C. Hoberg (via email)



**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

In the Matter of Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY's
Application For Fuel Clause Adjustment Revision
for MISO Day 2 charges

Case No. PU-05-131

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 21st day of May, 2007 by and between the North Dakota Large Industrial Energy Group ("Large Industrial Energy Group") and Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail") (collectively the "Parties"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in fair and reasonable rates for Otter Tail's retail customers in North Dakota.

BACKGROUND

In its March 21, 2007 Notice of Hearing in this matter, the North Dakota Public Service Commission ("Commission") identified the following three issues as needing resolution in this proceeding:

1. Whether the interim accounting treatment authorized for recovery of Day 2 market costs is appropriate and should be continued or a different or modified accounting treatment should be required.
2. Whether a percentage of wholesale revenues derived from off system energy sales should be shared with retail customers.
3. Whether any amounts already collected should be refunded with interest.

The following Settlement provides recommendations to the Commission on each of these issues. The following terms are taken, with minor modifications needed to make them North Dakota specific, from the Joint Report and Recommendation adopted by the Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR

MISO DAY 2 COSTS. The adoption of these terms by the Commission was requested by Mr. Larry Schedin, witness on behalf of the Large Industrial Energy Group, and supported in part by the Mr. Peter Beithon, witness on behalf of Otter Tail.

PROCEDURAL HISTORY

On March 1, 2005, Otter Tail filed an Application for revisions in its Fuel Clause Adjustment (“FCA”) tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO (“MISO”) Day 2 regional wholesale electric energy market. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing new accounting procedures for interim fuel clause recovery of the net costs of energy purchased through the new market subject to refund with interest in the event the Commission ultimately ordered a different or modified accounting treatment that results in lower charges. On January 24, 2007 the Commission granted intervention to the Large Industrial Energy Group. On April 20, 2007 the Large Industrial Energy Group filed Direct Testimony, and on May 14, 2007, Otter Tail filed Reply Testimony.

Terms of Settlement Agreement

The Parties agree to, and recommend the Commission approve the following provisions.

1. Except as regards Schedules 16 and 17¹ costs, discussed below, Otter Tail may recover the charges imposed by the Midwest Independent Transmission System Operator, Inc., for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of Otter Tail’s FCA. from the period April 1, 2005 through a period of at least three years after the date of the Commission Order accepting the Settlement Agreement.
2. Otter Tail may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005. Otter Tail may continue deferring Schedule 16 and 17 costs without interest until the earlier of Otter Tail’s next electric rate case or March 1, 2009. By

¹ See Appendix A hereto for a description of MISO schedules 16 and 17

March 1, 2009, Otter Tail shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until Otter Tail has a rate case addressing its proposal for recovering the balance.

3. In its next rate case, Otter Tail may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. Otter Tail may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, Otter Tail may seek to recover Schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final Commission approval.
4. Otter Tail shall use reasonable efforts to refund through the FCA all Schedule 16 and 17 costs previously recovered through the FCA by February 1, 2008. This refund amount shall be included in the deferral balance. For purposes of OTP's fuel clause true-up calculations, the refunds for Schedule 16 and 17 costs shall be reflected in the calculations for the periods during which they are made. The refund of Schedule 16 and 17 costs shall not affect prior true-ups.
5. Virtual Energy transactions in the Day 2 market are subject to the following conditions:
 - A. Otter Tail may use virtual energy transactions to take positions 1) from the Day-Ahead to the Real-Time market or 2) from the Real-Time to the Day-Ahead market, but only as a strategy to reduce risk and/or minimize costs assigned to retail customers. Otter Tail shall not engage in virtual energy transactions that affect the FCA for speculative purposes.
 - B. Virtual energy transactions that affect the FCA shall be summarized on a monthly basis and be included as a component of the monthly fuel clause reports to the Commission.

- C. Otter Tail shall restrict the use of virtual transactions that affect the FCA to 10% of total MWh subject to the FCA on a monthly basis with the understanding that the 10% threshold may be exceeded in any particular month, subject to the requirement that Otter Tail must explain the reasonableness of any deviation above the 10% threshold in its monthly fuel clause reporting. The 10% threshold does not apply to non-FCA virtual energy transactions (e.g. for non-asset based trading activities). The Commission may review and reset the 10% threshold as circumstances warrant.
6. Otter Tail shall adopt the following accounting practices:
- A. Recording each transaction to a separate sub-account of Accounts 447 and 555.
 - B. Recording to Account 555 on an aggregated basis any revenues and costs linked to Day 2 LMP, including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause.
 - C. Using net accounting for purchases and sales for owned generation facilities.
 - D. Continuing to use Accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they are accounted for today.
 - E. Continuing to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
 - F. Tracking in a separate sub-account each MISO charge and revenue.
 - G. Allocating all MISO Day 2 charges pursuant to the Minnesota Joint Report's Exhibit C, attached in revised form.

7. Otter Tail shall provide the following additional reporting requirements:
 - A. Otter Tail shall upon request and subject to a reasonable protective agreement in a form agreed to by Otter Tail and Large Industrial Energy Group shall supply the report it files in Minnesota which contains certain additional information regarding its plans with respect to acquiring fuel and purchased energy. The report must be provided within thirty days of receipt of the request and a signed protective agreement is in place. The Commission will have authority to establish the form of the protective order if the parties cannot agree
 - 1) Otter Tail shall include in its report an overview of its anticipated events and planned actions to address fuel clause costs, and the actions planned by Otter Tail to minimize or lower such costs whenever possible. Otter Tail shall provide a discussion of tools for managing fuel clause costs, including a) plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels, b) plans to hedge purchased energy costs (either through forward bilateral purchases or financial instruments), including how Otter Tail will plan for and cover fuel and energy risk during planned unit outages, and c) where deemed appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of FTRs in the MISO Day 2 Market.
 - 2) Customers may petition to intervene and seek either a technical review or, pursuant to appropriate protective agreements, be allowed to conduct an audit of Otter Tail's fuel and energy costs to review the prudence of Otter Tail's actions in relation to the market.
 - 3) Otter Tail shall provide and update a list of the network resources that it designates used to serve native load.

- B. To help customers manage their energy costs, Otter Tail shall provide large industrial customers who request the information and who sign a reasonable protective agreement in a form approved by Otter Tail and the Large Industrial Users, an annual FCA Forecast of the cost per MWh of fuel and purchased power costs for the next 12 months. This FCA Forecast shall include all fuel and energy costs associated with the operation of Otter Tail's system, in addition to projected MISO Day 2 costs and revenues. The FCA Forecast shall identify major changes that impact the stability of the forecast resulting from underlying changes in Otter Tail's cost inputs. The FCA Forecast shall also address projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Finally, Otter Tail shall explain the reasons for deviations in forecasts from actual costs in the previous year.
- C. Otter Tail shall prepare a summary of the information provided under paragraph B above, stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast. Otter Tail shall update its FCA Forecast whenever deviations from the current forecast are sufficiently material such that it requires a re-forecast for the next 12-month period. Otter Tail shall attempt to respond in a timely manner to questions from customers who have signed a protective agreement.
- D. Otter Tail shall meet with interested parties to discuss the FCA Forecast, its progress in achieving the FCA Forecast, and address any new proposals in the MISO Day 2 Market. Protective agreements governing disclosure of confidential information may be necessary.
- E. Otter Tail shall, upon request and subject to the above-described protective agreement, provide to the Large Industrial Users fuel and purchased energy forecasts for each monthly FCA filing in the same form as Otter Tail provides in Minnesota, which Otter Tail shall endeavor to provide three days prior to the first day of the FCA billing month. To the extent the monthly fuel and purchased

energy FCA Forecast exceeds the budget for that month set forth in the then current FCA Forecast by more than 10%, Otter Tail shall provide an explanation of the cause(s) of this change.

- F. In the event that Otter Tail's forecast of fuel and energy costs for a month deviates from actual fuel and energy costs by 15% or more, Otter Tail shall prepare a monthly deviation explanation quantifying the major reasons such as unit outages, congestion costs, weather, and fuel price changes. Otter Tail shall explain how it can control these costs, or the extent to which it is unable to control these costs.
 - G. Otter Tail shall use the monthly FCA reporting format as set forth in the Minnesota Joint Report's Exhibit D, attached in revised form (with minor variations permitted), listing each Day 2 charge type grouped into seven categories and providing cumulative data for the calendar year.
 - H. Otter Tail shall supplement its monthly fuel clause filing with information on significant events affecting that month's fuel clause costs.
8. Otter Tail shall address wholesale revenue margin sharing issues in its next rate case, which shall be filed no later than November 1, 2008, unless Otter Tail on or before that date makes a showing of good cause why a later filing is preferable, but in no event later than December 31, 2008. In its rate case filing, Otter Tail shall either propose a mechanism to credit asset-based wholesale margins through its fuel clause, like the mechanism and percentage approved for asset-based margins for Xcel Energy in its most recent Minnesota Rate Case, Docket No. E-002/GR-05-1428, or explain why such a mechanism should not be adopted. Interim rates shall be established using the same sharing mechanism proposed by Otter Tail for establishing final rates.
9. Otter Tail shall use its lowest cost generation or resource to serve its ratepayers.

10. Otter Tail shall challenge, both at the administrative level and through appeal if necessary, any FERC action that would require it to purchase energy to serve native load customers at LMP market clearing prices without the associated offset, as well as challenge any action that would preclude the utilities from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load as currently occurs under the MISO Day 2 tariff.
11. The approval for cost recovery as outlined in this Settlement Agreement shall terminate 60 days after the effective date of any FERC final decision and order having the effect of requiring Otter Tail to purchase energy to serve native load customers in whole or in part at LMP market clearing prices, action that would prevent Otter Tail from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load, or any other action preventing Otter Tail from using its lowest cost generation or resource to serve its native load ratepayers.

ADDITIONAL REQUEST BY LARGE ENERGY GROUP

The Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS, also opened an investigation and directed the Minnesota Department of Commerce (“Department”) by February 2009 to conduct a comprehensive review of the consequence of MISO Day 2 operations on Minnesota ratepayers and shall recommend changes as appropriate. All of the Minnesota utilities were required to provide relevant data to the Department in their AAA reports due September 1, 2008. The Large Energy Group requests that the Commission open a similar investigation in North Dakota, and Otter Tail has agreed not to object to such an investigation.

OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the

Company's next general rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The Company shall within 30 days of the Order approving the Settlement file amended tariffs as necessary to reflect the change in the recovery of Schedule 16 and 17 charges.

Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Counterparts

This Settlement Agreement may be executed in counterparts.

Dated this 12th day of July, 2007.

Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail")

By: Bruce Gerhardson by Michael Swaley
Bruce Gerhardson
Associate General Counsel

Dated this 13 day of July, 2007.

ND Large Industrial Energy Group

By: Thomas D. Kelsch
Thomas D. Kelsch

Description of Schedules 16 and 17 - Market Administration Charges

The costs of operating the Day Ahead, Real Time and FTR markets are known as MISO Schedule 16 and Schedule 17 expenses and as Miscellaneous expenses.

Schedule 16 Financial Transmission Rights Market Administration Amount

The Financial Transmission Rights Market Administration Amount, referred to as MISO Schedule 16, recovers the cost of MISO operating the FTR Markets. 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 (e.g., by utility) for the Operating Day. The Schedule 16 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Day-Ahead Market Administration Amount

The Day-Ahead Market Administration Amount in conjunction with the Real-Time Market Administration Amount, collectively referred to as MISO Schedule 17, recover the cost of MISO 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 in the Day Ahead Energy Market. 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 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 Utility'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 energy volume into

and out of the Commercial Node; in short, it is based on the summation of generation plus load volumes multiplied by the rate for Schedule 17. The Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

Schedule 17 Real-Time Market Administration Amount

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

For each utility for an Operating Day, Market Settlements assesses an administration charge on the Asset Owner's participation in the Real-Time Energy Market. The Utility'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; in short, it is based on the summation of generation plus load volumes, less those volumes which cleared the Day-Ahead market multiplied by the rate for Schedule 17. The Schedule 17 administration charge rate is subject to change based on costs incurred by Midwest ISO.

The following is Exhibit C from the June 22, 2006

Minnesota Joint Report on MISO Day 2

(as referred to in item 6.G. of the settlement agreement in Case PU-05-131)

**ATTACHED HERETO
IS
EXHIBIT C**

Cost Allocation

For illustration, we assume that a hypothetical utility had the following transactions in a given hour:

- 1) DA Load forecast of 1000MW. All load submitted to the DA market. The DA LMP at the load zone was \$30/MWh.
- 2) The company's only generator was sold DA. The unit is 800MW and the LMP was \$28/MWh. 700MW are assigned to retail and 100MW are assigned to Asset Sales.
- 3) The company had a bilateral purchase from Manitoba Hydro to serve native load. The purchase was for 100MW cleared in the DA market and the LMP was \$26/MWh. This is a DA physical import.
- 4) The company made a 200MW DA bilateral purchase from another MISO member to serve native load. This is a DA Fin Sched at a company node. From the delivery point to the company's load zone, congestion was \$1/MWh and losses were \$2/MWh.
- 5) The company purchased 50MW bilaterally at the Minnesota Hub and sold it bilaterally at Cnergy Hub as a Trading Sale. The LMP at Cnergy was \$35/MWh and the LMP at Minnesota was \$31/MWh. The company was responsible for congestion and losses from Minnesota Hub to Cnergy Hub. Losses were \$3/MWh and congestion was \$1/MWh.

Notes

DA refers to Day Ahead. RT refers to Real-Time.
None of the companies have Carve-Out GFA transactions.
Other Tail Power is the only company with Option B GFA transactions.

No.	Charge Type	Native Load	Asset Sales	Trading (Non-Asset) Sales	Method
Day Ahead & Real Time Asset & Non Asset Energy & Loss					
1	DA Asset Energy	DA Generation (LMP x MWh) + DA Load (LMP x MWh) + DA Fin Sched (LMP x MWh) (\$28/MWh x 700MWh) + (\$30/MWh x 1000MWh) + (\$30/MWh x 200MWh) = \$400 [1, 2, 4]	DA Generation (LMP x MWh) (\$28MWh x 100MWh) = \$2800 [2]	DA Fin Sched (LMP x MWh) Not illustrated	Direct assignment using calculations noted
3	DA Fin Sched Losses	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$2/MWh x 200MWh = \$400 [4]	N/A	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$3/MWh x 50MWh = \$150 [5]	Direct assignment using calculations noted
5	DA Non-Asset Energy	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh) (\$26/MWh x 100MWh) = \$2600 [3]	N/A	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh) (\$35/MWh x 50MWh) + (\$35/MWh x 50MWh) = \$350 [5]	Direct assignment using calculations noted
13	RT Asset Energy	Load Imbalance (LMP x MWh) + Generation Imbalance (LMP x MWh) + Residual Load (LMP x MWh) + RT Fin Sched when node belongs to Asset Owner (LMP x MWh)	Generation Imbalance (LMP x MWh)	RT Fin Sched when node belongs to Asset Owner (LMP x MWh)	Direct assignment using calculations noted
14	RT Distribution of Losses	All assigned to native load	N/A	N/A	Direct assignment using calculations noted
16	RT Fin Sched Losses	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	N/A	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	Direct assignment using calculations noted
22	RT Non-Asset Energy	RT Physical Schedule (LMP x MWh) + RT Fin Sched when node doesn't belong to Asset Owner (LMP x MWh)	N/A	RT Physical Schedule (LMP x MWh) + RT Fin Sched when node doesn't belong to Asset Owner (LMP x MWh)	Direct assignment using calculations noted
Virtual Energy					
12	DA Virtual Energy	DA Virtual (LMP x MWh)	N/A	DA Virtual (LMP x MWh)	Direct assignment using calculations noted
27	RT Virtual Energy	RT Virtual (LMP x MWh)	N/A	RT Virtual (LMP x MWh)	Direct assignment using calculations noted
Options Schedules 16 & 17					
4	DA Market Admin	[DA Generation (MWh) + DA Load (MWh) + DA Physical Schedules (MWh) + DA Virtual Schedule (MWh) + DA Fin Sched with node not belonging to Asset Owner (MWh)] x DA Admin Rate	DA Generation (MWh) x DA Admin Rate	[DA Fin Sched with node not belonging to Asset Owner (MWh) + DA Virtual Schedule (MWh)] x DA Admin Rate	Direct assignment using calculations noted
19	RT Market Admin	[Load Imbalance (MWh) + Generation Imbalance (MWh) + RT Fin Sched when node doesn't belong to Asset Owner (MWh)] x RT Admin Rate	Generation Imbalance (MWh) x RT Admin Rate	[RT Physical Schedules (MWh) + RT Fin Sched when node doesn't belong to Asset Owner (MWh)] x RT Admin Rate	Direct assignment using calculations noted
23	FTR Market Admin	Held FTRs (MWh) x FTR Admin Rate	Held FTRs (MWh) x FTR Admin Rate	Held FTRs (MWh) x FTR Admin Rate	Direct assignment using calculations noted
Congest & FTRs					
2	DA Fin Sched Congestion	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$1/MWh x 200MWh = \$200 [4]	N/A	DA Fin Sched (LMP ₁ - LMP ₂) x MWh \$1/MWh x 50MWh = \$50 [5]	Direct assignment using calculations noted
15	RT Fin Sched Congestion	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	N/A	RT Fin Sched (LMP ₁ - LMP ₂) x MWh	Direct assignment using calculations noted
28	FTR Hourly Allocation	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁ when difference is positive)] + FTR Payments (LMP ₂ - LMP ₁ when difference is negative)	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁ when difference is positive)] + FTR Payments (LMP ₂ - LMP ₁ when difference is negative)	FTR Receipts [Prorating Factor x (LMP ₂ - LMP ₁ when difference is positive)] + FTR Payments (LMP ₂ - LMP ₁ when difference is negative)	Direct assignment using calculations noted
30	FTR Monthly Allocation	FTR Hourly Allocation Receipts for the given month	FTR Hourly Allocation Receipts for the given month.	FTR Hourly Allocation Receipts for the given month.	Allocate using the quantities determined in the calculation.
32	FTR Yearly Allocation	FTR Hourly Allocation Receipts for the given year	FTR Hourly Allocation Receipts for the given year.	FTR Hourly Allocation Receipts for the given year.	Allocate using the quantities determined in the calculation.
31	FTR Transaction Amount	Manually Assigned	Manually Assigned	Manually Assigned	Direct assignment using calculations noted
RSG & Make Whole Payments					
10	DA RSG Distribution	DA Load (MWh) + DA Net Exports (MWh) + DA Virtual Purchases (MWh)	N/A	DA Net Exports (MWh) + DA Virtual Purchases (MWh)	Allocate using the quantities determined in the calculation.
11	DA RSG Make Whole Payment	DA Committed Gen (MWh)	DA Committed Gen (MWh)	N/A	Allocate using the quantities determined in the calculation.
24	RT RSG First Pass Distribution	Load Imbalance (MWh) + Generation Imbalance (MWh) + RT Net Imports and Exports (MWh)	Generation Imbalance (MWh)	RT Net Imports/Exports (MWh)	Allocate using the quantities determined in the calculation.
25	RT RSG Make Whole Payment	All assigned to asset sales	All assigned to asset sales	N/A	Direct assignment using calculations noted
Revenue Neutrality Uplift					
23	RT RNJ	Metered Load (MWh) + Physical Exports (MWh)	N/A	Physical Exports (MWh)	Allocate using the quantities determined in the calculation.
Other Charges					
20	RT Miscellaneous	Manually Assigned	Manually Assigned	Manually Assigned	Direct assignment using calculations noted
21	RT Net Inadvertent	All assigned to native load	N/A	N/A	Direct assignment using calculations noted
26	RT Unrestricted Deviation	Absolute Value of Generation Imbalance (MWh)	Absolute Value of Generation Imbalance (MWh)	N/A	Allocate using the quantities determined in the calculation.
Grandfathered Charge Types					
8	DA Congestion Rebate on Carve-Out GFAs	All assigned to native load	N/A	N/A	Direct assignment using calculations noted
9	DA Loss Rebate on Option B GFAs (OTF only)	All assigned to native load.	N/A	N/A	Direct assignment using calculations noted
17	RT Congestion Rebate on Carve-Out GFAs	All assigned to native load.	N/A	N/A	N/A
18	RT Loss Rebate on Carve-Out GFAs	All assigned to native load.	N/A	N/A	N/A
Total MISO Day 2 Charges					

The following is Exhibit D from the June 22, 2006

Minnesota Joint Report on MISO Day 2

(as referred to in item 7.G. of the settlement agreement in Case PU-05-131)

**ATTACHED HERETO
IS
EXHIBIT D**

**Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce**

Fuel adjustment clause data for the billing month of: June-06

Line No.		March-06	April-06	Total
	Cost of Fuel			
1	Company's Generating Stations (Account 151)	-	-	-
2	MISO Day 2 Charges (not Schedule 16 & 17) (Account 555)	-	-	-
2	Plus Fuel Costs of Purchased Energy (Account 555)	-	-	-
3	Less Fuel Cost Recovery Inter-System Sales (Account 447)	-	-	-
4	Total Cost of Fuel	-	-	-
	KWh Sales			
5	Total Sales of Electricity	-	-	-
6	Less Inter-System Sales	-	-	-
7	Total kWh	-	-	-
8	Cost of Fuel per kWh (cents/kWh)			#DIV/0!
	Fuel Adjustment per kWh			
9	Fuel Adjustment Clause #16 :			
	Fuel Cost			#DIV/0!
	Less Base			-
	Fuel Adjustment		¢ / kWh	
10	Fuel Adjustment Clause #17 :			
	Fuel Cost			-
	Less Base			-
	Fuel Adjustment		- ¢ / kWh	

**Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce**

Kilowatt-hour Information for the Billing Month of: April-06

Line No.		kWh Sales	
	Minnesota Jurisdiction - Retail Sales		
1	Subject to Fuel Clause #16	679,890,187	kWh
2	Subject to Fuel Clause #17*	442,673	kWh
3	Non-Fuel Clause Sales	48,190,317	kWh
4	Total	728,523,177	kWh
	Non-Minnesota Jurisdiction Sales		
5	Sales for Resale	306,943,052	kWh
6	Total Sales of Electricity	1,035,466,229	kWh
7	Less Inter-System Sales	251,276,959	kWh
8	Total kWh Sales	784,189,270	kWh

Notes:

- The June 2006 bills will be mailed between June 1, 2006 and July 5, 2006.
- A majority of the kWh usage to which the fuel clause adjustment rates on this form are applicable will occur during the calendar month of June 2006 for all customers on Company's Large Power Service rate. A majority of the kWh usage for all other retail customers will occur during the calendar month of May 2006.
- Fuel Adjustment Clause #17: Because the rates containing this adjustment are based on annual kWh use, the fuel adjustment per kilowatt-hour applicable for the June billing period applies for the entire annual period (June through May).

Prepared by:

Date: May 24, 2006

Patty Tolvonen
Senior Accounting Analyst

MINNESOTA POWER
MISO MONTHLY ALLOCATION

MONTH: Apr-06

Charge Type	Account Number	Total Apr-06	FAC			Non-FAC
			Relat	Resale	Tcta'	Other
Day Ahead Asset Energy Amount	4470-0000 or 5551-0000 or 5551-0050					
Day Ahead Non-Asset Energy Amount	5551-0027					
Day Ahead Virtual Energy Amount	5551-0030					
Real Time Asset Energy Amount	4470-0000 or 5551-0000 or 5551-0050					
Real Time Non-Asset Energy Amount	5551-0043					
Real Time Virtual Energy Amount	5551-0049					
Energy Total						
Day Ahead Market Administration Amount	5551-0020					
Day Ahead Financial Bilateral Transaction Congestion Amount	5551-0021					
Day Ahead Financial Bilateral Transaction Loss Amount	5551-0022					
Day Ahead Congestion Rebate on Carry-Out Grandfathered Agreements	5551-0023					
Day Ahead Losses Rebate on Carry-Out Grandfathered Agreements	5551-0024					
Day Ahead Congestion Rebate on Option B Grandfathered Agreements	5551-0025					
Day Ahead Losses Rebate on Option B Grandfathered Agreements	5551-0026					
Day Ahead Revenue Sufficiency Guarantee Distribution Amount	5551-0028					
Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	5551-0029					
Financial Transmission Rights Market Administration Amount	5551-0031					
Financial Transmission Rights Hourly Allocation Amount	5551-0032					
Financial Transmission Rights Monthly Allocation Amount	5551-0033					
Financial Transmission Rights Transaction Amount	5551-0034					
Financial Transmission Rights Yearly Allocation Amount	5551-0035					
Real Time Market Administration Amount	5551-0036					
Real Time Financial Bilateral Transaction Congestion Amount	5551-0037					
Real Time Financial Bilateral Transaction Loss Amount	5551-0038					
Real Time Congestion Rebate on Carry-Out Grandfathered Agreements	5551-0039					
Real Time Losses Rebate on Carry-Out Grandfathered Agreements	5551-0040					
Real Time Distribution of Losses Amount	5551-0041					
Real Time Miscellaneous Amount	5551-0042					
Real Time Net Inadvertent Distributions Amount	5551-0044					
Real Time Revenue Neutrality Uplift Amount	5551-0045					
Real Time Revenue Sufficiency Guarantee First Pass Out Amount	5551-0046					
Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	5551-0047					
Real Time Uninstructed Deviation Amount	5551-0048					
Energy Charges Total						
Grand Total						

Monthly MISO Day 2 Charges - April - December 2005
 Total MP charges for the period

Charge Type Description	April 2005	May 2005	June 2005	July 2005	August 2005	September 2005	October 2005	Nov
1 Day Ahead Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
3 Day Ahead Financial Bilateral Transaction Loss	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
5 Day Ahead Non Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
13 Real Time Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
14 Real Time Distribution Losses	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
18 Real Time Financial Bilateral Loss	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
22 Real Time Non Asset Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
12 Day Ahead Virtual Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
27 Real Time Virtual Energy	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
4 Day Ahead Market Administration (Schedule 17)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
19 Real Time Market Administration (Schedule 17)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
20 Financial Transmission Rights Administration (Schedule 16)	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
2 Day Ahead Financial Bilateral Transaction Congestion	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
15 Real Time Financial Bilateral Congestion	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
28 Financial Transmission Rights Hourly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
30 Financial Transmission Rights Monthly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
32 Financial Transmission Rights Yearly Allocation	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
31 Financial Transmission Rights Transaction	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
10 Day Ahead Revenue Sufficiency Guarantee Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
11 Day Ahead Revenue Sufficiency Make Whole Payments	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
20 Real Time Miscellaneous	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
21 Real Time Not Inadvertent Distribution	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
23 Real Time Revenue Neutrality Uplift Amount	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
26 Real Time Unstructured Deviation Amount	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
0 Day Ahead Congestion Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
8 Day Ahead Congestion Rebate on Option B-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
9 Day Ahead Loss Rebate on Option B-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
17 Real Time Congestion Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$
16 Real Time Loss Rebate on Carve Out-Grandfathered	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$

Note. A negative number indicates an amount due from MISO
 and a positive number indicates an amount due to MISO

Summary by charge type

**Minnesota Power
Energy Purchases and Sales
June 2005**

Purchases	% MWh	MWh	Cost		
Generation	-	-	-		
Short Term Bilaterals	-	-	-		
Long Term Bilaterals	-	-	-		
MISO	-	-	-		
Total Purchases	-	-	-		
Sales	% MWh	MWh	Fuel Cost	Billing	
Short Term Bilaterals	-	-	-	-	-
Long Term Bilaterals	-	-	-	-	-
MISO	-	-	-	-	-
Retail Non-Firm	-	-	-	-	-
FAC Retail	-	-	-	-	-
FAC FERC Jurisdictional	-	-	-	-	-
Total Sales	-	-	-	-	-
Difference ^{1/}		-			

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE)
COMMISSION OTTER TAIL CORPORATION) Docket No. PU-05-131
COST OF FUEL ADJUSTMENT CLAUSE)
TARIFF)

STATE OF NORTH DAKOTA)
) ss. **AFFIDAVIT OF SERVICE**
COUNTY OF MORTON) **BY MAIL & EMAIL**

DEBRA K. ROEHRICH being first duly sworn, on oath, deposes and says: That she is a citizen of the United States, over the age of eighteen and not a party to the above-entitled action.

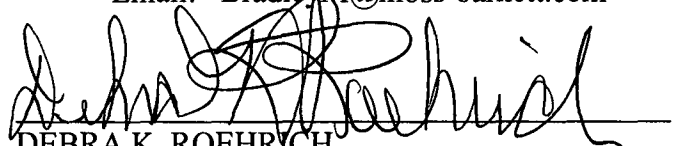
That on the 13th day of July, 2007, this affiant deposited in the United States Post Office at Mandan, North Dakota, and faxed a true and correct copy of the following document(s) in the above-captioned action:

1. Settlement Agreement w/attachments.

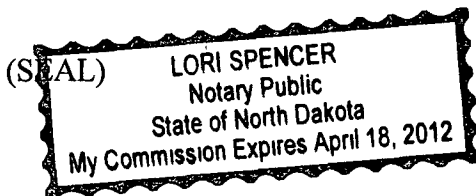
That a copy of the above document(s) was securely enclosed in an envelope with postage duly prepaid, and addressed as follows:

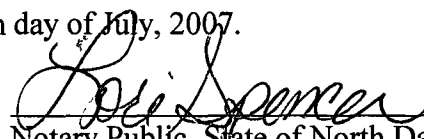
BRUCE GERHARDSON
OTTERTAIL CORPORATION
215 S CASCADE STREET
FERGUS FALLS MN 56538
Email: bgerhardson@ottertail.com

MICHAEL J BRADLEY
MOSS & BARNETT
4800 WELLS FARGO CENTER
90 SOUTH 7TH STREET
MINNEAPOLIS MN 55402-4129
Email: BradleyM@moss-barnett.com


DEBRA K. ROEHRICH

Subscribed and sworn to before me this 13th day of July, 2007.




Notary Public, State of North Dakota

North Dakota Public Service Commission
INFORMAL HEARING
July 11, 2007

Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff

PU-05-131
Filed: 3/1/05

Summary of Settlement: On May 21, 2007 a settlement agreement was entered into by the North Dakota Large Industrial Energy Group and Otter Tail that would resolve all outstanding issues in the captioned proceeding. In short summary, the agreement is essentially the same as what has been established in Minnesota. The agreement primarily provides that Otter Tail may continue to recover MISO costs, other than Schedules 16 and 17 costs, for a period of at least three years after the settlement agreement is accepted by the Commission. Over the next 12 months Otter Tail would refund all Schedule 16 and 17 costs that have been recovered through the FCA. Otter Tail may defer the refunded and future Schedule 16 and 17 costs without interest until the earlier of its next rate case or March 1, 2009. By March 1, 2009, Otter Tail would begin amortizing the deferred balance over a period ending March 1, 2012. Otter Tail may seek to recover deferred Schedule 16 and 17 costs during its next rate case. The settlement agreement also provides additional requirements concerning virtual energy transactions along with accounting practices and reporting requirements.

Recommendation: Staff recommends the Commission approve the settlement agreement with clarification that Otter Tail still bears the burden of showing that the deferred Schedule 16 and 17 cost amortization should be allowed in test year revenue requirements during its next rate case.

Discussion: Since the December 8, 2006 staff report in this matter, staff has become aware of a FERC decision that Midwest ISO Schedule 16 and 17 administrative cost adders are no longer to be recorded as a cost of fuel and purchased energy in FERC Account 555. Staff notes that MDU's response was to credit all of the Schedule 16 and 17 costs that it had recovered back to customers through its FCA billings. In view of the FERC's decision though North Dakota PSC accounting practices are not bound by it, and to be consistent with MDU's response, staff supports the refunding of Schedule 16 & 17 charges and recommends accepting the procedure described in the settlement agreement. However, as contemplated in paragraph 3 of the settlement, staff wishes to reserve the right to investigate whether any proposed future rate case recovery of deferred charges is necessary or appropriate. Staff is especially interested in whether the level of Otter Tail's earnings during the deferral period, including earnings from asset and non-asset based intersystem sales, was sufficient such that those deferrals have already been recovered through other rates.

Prepared by: Jerry Lein



OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.nd.gov/oah

May 23, 2007

William W Binek
Public Service Commission
600 East Boulevard Avenue, Dept 408
Bismarck, ND 58505-0480

Re: Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
Case No PU-05-131
OAH File No 20070083



Dear Mr Binek

On February 27, 2007, you requested the designation of an administrative law judge to preside as a procedural hearing officer in the matter of Otter Tail Corporation (PU-05-131) Prior to the hearing you informed me that the matter would likely be settled Today I received a copy of the Proposed Settlement Agreement It appears that the matter will be settled Accordingly, I am closing our file on this matter and returning that portion of the record I have in my possession to you Enclosed are copies of documents that have been transmitted to us, as well as originals and copies of documents received while the file was in our possession, for filing with the official agency record of this matter

If this matter is not settled and a hearing will be required, please submit a new Request for Administrative Law Judge

Thank you for your attention to this matter.

Sincerely,

Allen C Hoberg
Administrative Law Judge

ACH/eap

Encl

cc Bruce Gerhardson
Otter Tail Corporation
Thomas D Kelsch
Kelsch, Kelsch, Ruff & Kranda

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 21st day of May, 2007 by and between the ND Large Industrial Energy Group (“Large Industrial Energy Group”) and Otter Tail Corporation d/b/a Otter Tail Power Company (“Otter Tail”) (collectively the “Parties”). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in fair and reasonable rates for Otter Tail’s retail customers in North Dakota.

BACKGROUND

In its March 21, 2007 Notice of Hearing in this matter, the North Dakota Public Service Commission (“Commission”) identified the following three issues as needing resolution in this proceeding:

1. Whether the interim accounting treatment authorized for recovery of Day 2 market costs is appropriate and should be continued or a different or modified accounting treatment should be required.
2. Whether a percentage of wholesale revenues derived from off system energy sales should be shared with retail customers.
3. Whether any amounts already collected should be refunded with interest.

The following Settlement provides recommendations to the Commission on each of these issues. The following terms are taken, with minor modifications needed to make them North Dakota specific, from the Joint Report and Recommendation adopted by the Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS. The adoption of these terms by the Commission was requested by Mr.

Larry Schedin, witness on behalf of the Large Industrial Energy Group, and supported in part by the Mr. Peter Biethon, witness on behalf of Otter Tail.

PROCEDURAL HISTORY

On March 1, 2005, Otter Tail filed revisions in its Fuel Cost Adjustment tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO (“MISO”) Day 2 regional wholesale electric energy market. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing new accounting procedures for interim fuel clause recovery of the net costs of energy purchased through the new market subject to refund with interest in the event the Commission ultimately ordered a different or modified accounting treatment that results in lower charges. On January 24, 2007 the Commission granted intervention to the Large Industrial Energy Group. On April 20, 2007 the Large Industrial Energy Group filed Direct Testimony, and on May 14, 2007, Otter Tail filed Reply Testimony.

Terms of Settlement Agreement

The Parties agree to, and recommend the Commission approve the following provisions.

1. Except as regards Schedules 16 and 17 costs, discussed below, Otter Tail may recover the charges imposed by the Midwest Independent Transmission System Operator, Inc., for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of Otter Tail’s FCA. from the period April 1, 2005 through a period of at least three years after the date of the Commission Order accepting the Settlement Agreement.
2. Otter Tail may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005. Otter Tail may continue deferring Schedule 16 and 17 costs without interest until the earlier of Otter Tail’s next electric rate case or March 1, 2009. By March 1, 2009, Otter Tail shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until Otter Tail has a rate case addressing its proposal for recovering the balance.

3. In its next rate case, Otter Tail may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. Otter Tail may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, Otter Tail may seek to recover Schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final Commission approval.
4. Over the next twelve months, Otter Tail shall refund through the FCA all Schedule 16 and 17 costs previously recovered through the FCA. This refund amount shall be established as or included in the deferral balance.

For purposes of OTP's fuel clause true-up calculations, the refunds for Schedule 16 and 17 costs shall be reflected in the calculations for the periods during which they are made. The refund of Schedule 16 and 17 costs shall not affect prior true-ups.

5. Virtual Energy transactions in the Day 2 market are subject to the following conditions:
 - A. Otter Tail may use virtual energy transactions to take positions 1) from the Day-Ahead to the Real-Time market or 2) from the Real-Time to the Day-Ahead market, but only as a strategy to reduce risk and/or minimize costs assigned to retail customers. Otter Tail shall not engage in virtual energy transactions that affect the FCA for speculative purposes.
 - B. Virtual energy transactions that affect the FCA shall be summarized on a monthly basis and be included as a component of the monthly fuel clause reports to the Commission.
 - C. Otter Tail shall restrict the use of virtual transactions that affect the FCA to 10% of total MWh subject to the FCA on a monthly basis with the understanding that

the 10% threshold may be exceeded in any particular month, subject to the requirement that Otter Tail must explain the reasonableness of any deviation above the 10% threshold in its monthly fuel clause reporting. The 10% threshold does not apply to non-FCA virtual energy transactions (e.g. for non-asset based trading activities). The Commission may review and reset the 10% threshold as circumstances warrant.

6. Otter Tail shall adopt the following accounting practices:
 - A. Recording each transaction to a separate sub-account of Accounts 447 and 555.
 - B. Recording to Account 555 on an aggregated basis any revenues and costs linked to Day 2 LMP, including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause.
 - C. Using net accounting for purchases and sales for owned generation facilities.
 - D. Continuing to use Accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they are accounted for today.
 - E. Continuing to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
 - F. Tracking in a separate sub-account each MISO charge and revenue.
 - G. Allocating all MISO Day 2 charges pursuant to the Joint Report's Exhibit C, attached in revised form.
7. Otter Tail shall provide to the Commission the following additional reporting requirements:

- A. Otter Tail shall upon request and subject to a reasonable protective agreement in a form agreed to by Otter Tail and Large Industrial Energy Group shall supply the report it files in Minnesota which contains certain additional information regarding its plans with respect to acquiring fuel and purchased energy. The report must be provided within thirty days of receipt of the request and a signed protective agreement is in place. The Commission will have authority to establish the form of the protective order if the parties cannot agree.
- 1) Otter Tail shall include in its report an overview of its anticipated events and planned actions to address fuel clause costs, and the actions planned by Otter Tail to minimize or lower such costs whenever possible. Otter Tail shall provide a discussion of tools for managing fuel clause costs, including a) plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels, b) plans to hedge purchased energy costs (either through forward bilateral purchases or financial instruments), including how Otter Tail will plan for and cover fuel and energy risk during planned unit outages, and c) where deemed appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of FTRs in the MISO Day 2 Market.
 - 2) Customers may petition to intervene and seek either a technical review or, pursuant to appropriate protective agreements, be allowed to conduct an audit of Otter Tail's fuel and energy costs to review the prudence of Otter Tail's actions in relation to the market.
 - 3) Otter Tail shall provide and update a list of the network resources that it designates used to serve native load.
- B. To help customers manage their energy costs, Otter Tail shall provide large industrial customers who request the information and who sign a reasonable

protective agreement in a form approved by Otter Tail and the Large Industrial Users, an annual FCA Forecast of the cost per MWh of fuel and purchased power costs for the next 12 months. This FCA Forecast shall include all fuel and energy costs associated with the operation of Otter Tail's system, in addition to projected MISO Day 2 costs and revenues. The FCA Forecast shall identify major changes that impact the stability of the forecast resulting from underlying changes in Otter Tail's cost inputs. The FCA Forecast shall also address projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Finally, Otter Tail shall explain the reasons for deviations in forecasts from actual costs in the previous year.

- C. Otter Tail shall prepare a summary of the filing provided under paragraph B above, stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast. Otter Tail shall update its FCA Forecast whenever deviations from the current forecast are sufficiently material such that it requires a re-forecast for the next 12-month period. Otter Tail shall attempt to respond in a timely manner to questions from customers who have signed a protective agreement.
- D. Otter Tail shall meet with interested parties to discuss the FCA Forecast, its progress in achieving the FCA Forecast, and address any new proposals in the MISO Day 2 Market. Protective agreements governing disclosure of confidential information may be necessary.
- E. Otter Tail shall, upon request and subject to the above-described protective agreement, provide to the Large Industrial Users fuel and purchased energy forecasts for each monthly FCA filing in the same form as Otter Tail provides in Minnesota, which Otter Tail shall endeavor to provide three days prior to the first day of the FCA billing month. To the extent the monthly fuel and purchased energy FCA Forecast exceeds the budget for that month set forth in the then

current FCA Forecast by more than 10%, Otter Tail shall provide an explanation of the cause(s) of this change.

- F. In the event that Otter Tail's forecast of fuel and energy costs for a month deviates from actual fuel and energy costs by 15% or more, Otter Tail shall prepare a monthly deviation explanation quantifying the major reasons such as unit outages, congestion costs, weather, and fuel price changes. Otter Tail shall explain how it can control these costs, or the extent to which it is unable to control these costs. .
 - G. Otter Tail shall use the monthly FCA reporting format as set forth in the Joint Report's Exhibit D, attached in revised form (with minor variations permitted), listing each Day 2 charge type grouped into seven categories and providing cumulative data for the calendar year.
 - H. Otter Tail shall supplement its monthly fuel clause report with information on significant events affecting that month's fuel clause costs.
8. Otter Tail shall address wholesale revenue margin sharing issues in its next rate case, which shall be filed no later than November 1, 2008, unless Otter Tail on or before that date makes a showing of good cause why a later filing is preferable, but in no event later than December 31, 2008. In its rate case filing, Otter Tail shall either propose a mechanism to credit asset-based wholesale margins through its fuel clause, like the mechanism and percentage approved for asset-based margins for Xcel Energy in its most recent Minnesota Rate Case, Docket No. E-002/GR-05-1428, or explain why such a mechanism should not be adopted. Interim rates shall be established using the same sharing mechanism proposed by Otter Tail for establishing final rates.
9. Otter Tail shall use its lowest cost generation or resource to serve its ratepayers.

10. Otter Tail shall challenge, both at the administrative level and through appeal if necessary, any FERC action that would require it to purchase energy to serve native load customers at LMP market clearing prices without the associated offset, as well as challenge any action that would preclude the utilities from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load as currently occurs under the MISO Day 2 tariff.
11. The approval for cost recovery as outlined in this Settlement Agreement shall terminate 60 days after the effective date of any FERC final decision and order having the effect of requiring Otter Tail to purchase energy to serve native load customers in whole or in part at LMP market clearing prices, action that would prevent Otter Tail from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load, or any other action preventing Otter Tail from using its lowest cost generation or resource to serve its native load ratepayers.

ADDITIONAL REQUEST BY LARGE ENERGY GROUP

The Minnesota Public Utilities Commission in its December 20, 2006 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS, also opened an investigation and directed the Minnesota Department of Commerce (“Department”) by February 2009 to conduct a comprehensive review of the consequence of MISO Day 2 operations on Minnesota ratepayers and shall recommend changes as appropriate. All of the Minnesota utilities were required to provide relevant data to the Department in their AAA reports due September 1, 2008. The Large Energy Group requests that the Commission open a similar investigation in North Dakota, and Otter Tail Power has agreed not to object to such an investigation.

OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the

Company's next general rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The Company shall within 30 days of the Order approving the Settlement file amended tariffs as necessary to reflect the change in the recovery of Schedule 16 and 17 charges.

Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

Counterparts

This Settlement Agreement may be executed in counterparts.

Dated this ____ day of May 2007.

Otter Tail Corporation d/b/a Otter Tail Power Company (“Otter Tail”)

By: _____
Bruce Gerhardson
Associate General Counsel

Dated this ____ day of May 2007.

ND Large Industrial Energy Group r

By: _____
Thomas D. Kelsch

Anderson, Lori D.

From: Binek, William W
Sent: Friday, May 18, 2007 10:47 AM
To: Hoberg, Allen C
Cc: -Grp-PSC Commissioners, -Grp-PSC Public Utilities, -Grp-PSC Legal
Subject: RE: NdPSC Case No. PU-05-131

I agree

William W Binek
Chief Counsel
ND Public Service Commission
600 East Boulevard Avenue, Dept 408
Bismarck ND 58505-0480
Phone 701-328-4088
Fax 701-328-2410
wbinek@nd.gov

From: Hoberg, Allen C.
Sent: Friday, May 18, 2007 8:05 AM
To: Binek, William W.
Subject: RE: NdPSC Case No. PU-05-131

Bill Under the circumstances, I expect that the Commission will not need me on Tuesday, correct? Allen

From: Binek, William W.
Sent: Friday, May 18, 2007 6:10 AM
To: -Grp-PSC Commissioners; Hoberg, Allen C.
Cc: -Grp-PSC Public Utilities; -Grp-PSC Legal
Subject: FW: NdPSC Case No. PU-05-131

William W Binek
Chief Counsel
ND Public Service Commission
600 East Boulevard Avenue, Dept 408
Bismarck ND 58505-0480
Phone 701-328-4088
Fax 701-328-2410
wbinek@nd.gov

From: Thomas D Kelsch [mailto:tdkelsch@kelschlaw.com]
Sent: Thursday, May 17, 2007 5:45 PM
To: Binek, William W.; Lein, Jerry R.; Bruce Gerhardson

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Pages 2

E-mail Confirmation that ALJ is NOT needed
Tues, May 22
by Public Service Commission
05/18/2007-mm Legal, Illona Jerry Annette Mike ALJ

5/18/2007

Cc: Larry Schedin; Kavita Maini; Eric_Hoegger@cargill.com; Steven B. Otto
Subject: NdPSC Case No. PU-05-131

Bill and Jerry,

This note is to confirm in writing the telephone conference we held earlier today. Representatives of OtterTail Power and the Large Industrial Users Group engaged in a settlement conference call on the above matter this afternoon. The parties have reached a tentative settlement of the matter in a telephone conference call with the ND PSC have requested the Commission to continue the formal hearing on the above matter scheduled for Tuesday May 22, 2007 at 9.00 a.m. Please let the Hearing Officer know of this proposed settlement.

It is intended that the parties will be present in person and by phone for the scheduled time of the hearing for the limited purpose of presenting the draft of the settlement to the Commission and to request the Commission to continue the hearing. The parties request that the Commission consider the proposed settlement at a future date in an informal hearing.

OtterTail Power will be preparing a draft of the settlement which is based on the settlement entered into by the Minnesota Public Utilities commission in its Order Establishing Accounting treatment for MISO day 2 costs issued on December 20, 2006. It is anticipated that a draft of the settlement will be presented to the Commission on or before the scheduled hearing on Tuesday, May 22.

I will be present at the Commission on behalf of the Intervenor, Large Industrial User Group, Bruce Gerhardson on behalf of OtterTail requests that he be permitted to participate by phone at 218-998-7108. The parties experts will be available by phone on Tuesday should the Commission have any questions at that time. The parties agree that a continuance of the hearing will allow the Commission adequate time to review the proposed settlement, and that the parties and their experts can be available at a future informal hearing to explain the settlement and to answer questions that the Commission and staff may have.

Thank you for consideration of this matter.
I am forwarding a copy of this email to Bruce Gerhardson.

Thomas D Kelsch
Kelsch Kelsch Ruff & Kranda
103 Collins Avenue, PO Box 1266
Mandan ND 58554-7266
Phone 701-663-9818 (toll free 1-888-663-9818)
Fax 701-663-9810
tdkelsch@kelschlaw.com

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5/18/2007

Anderson, Lori D.

From: Binek, William W
Sent: Friday, May 18, 2007 7 10 AM
To: -Grp-PSC Commissioners, Hoberg, Allen C
Cc: -Grp-PSC Public Utilities, -Grp-PSC Legal
Subject: FW NdPSC Case No PU-05-131

William W. Binek
 Chief Counsel
 ND Public Service Commission
 600 East Boulevard Avenue, Dept 408
 Bismarck ND 58505-0480
 Phone 701-328-4088
 Fax 701-328-2410
wbinek@nd.gov

From: Thomas D Kelsch [mailto:tdkelsch@kelschlaw.com]
Sent: Thursday, May 17, 2007 5:45 PM
To: Binek, William W.; Lein, Jerry R.; Bruce Gerhardson
Cc: Larry Schedin; Kavita Maini; Eric_Hoegger@cargill.com; Steven B. Otto
Subject: NdPSC Case No. PU-05-131

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Thank you for consideration of this matter.
 I am forwarding a copy of this email to Bruce Gerhardson.

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Pages 2

E-mail notification of proposed settlement
 agreement
 by Kelsch Kelsch Ruff & Kranda

5/18/2007

05/17/2007:mm Legal Ilona Jerry, Annette, Mike ALJ

Thomas D Kelsch
Kelsch Kelsch Ruff & Kranda
103 Collins Avenue, PO Box 1266
Mandan ND 58554-7266
Phone 701-663-9818 (toll free 1-888-663-9818)
Fax 701-663-9810
tdkelsch@kelschlaw.com

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Lein, Jerry R.

From: Thomas D Kelsch [tdkelsch@kelschlaw.com]
Sent: Tuesday, May 15, 2007 5:50 PM
To: Bruce Gerhardson, Lein, Jerry R
Cc: Larry Schedin, Kavita Maini, Steven B Otto, Eric_Hoegger@cargill.com
Subject: Response to Narrowing of Issues Case No PU-05-131
Attachments: 12039 OTP Large Ind Users Group Narrowed Issue List 05-14-07.doc

Bruce and Jerry,

I am attaching a copy of the Large Industrial Users Groups response to OTP's proposed narrowing of issues for the hearing on May 22, 2007. If you have any questions please give me a call.

Tom D Kelsch

Thomas D Kelsch

Kelsch Kelsch Ruff & Kranda

103 Collins Avenue, PO Box 1266

Mandan ND 58554-7266

Phone 701-663-9818 (toll free 1-888-663-9818)

Fax 701-663-9810

tdkelsch@kelschlaw.com

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NARROWED ISSUES LIST REVISED
05-14-07 by LARRY L SCHEDIN

1. Does the monthly volatility in the FCA indicate that: 1) the market is not working properly for OTP, 2) OTP is not properly managing its market participation, 3) OTP is not properly charging costs to retail customers, or 4) some combination of the foregoing? If the answer to any of these is yes, what should be required of OTP?

2. Because OTP has not been applying its Fuel Cost Adjustment Rider (FCA) as written (see response to Large Industrial Interrogatory No.1) and because of items in foregoing issue No. 1, should the Commission select a major, independent accounting firm to analyze OTP's MISO accounting, FCA application, and market strategy and to recommend changes and improvements, all at OTP's expense?

3. Are differences between monthly retail system energy requirements as utilized in the calculation of the FCA and energy requirements as calculated and measured from system hourly load data indicative of a problem or accounting inconsistency? If the answer is yes, what should be required of OTP?

4. Should asset-based and non-asset based margins received since the inception of MISO Day 2 (April 1, 2005) be credited to the FCA, and does the PBR Agreement properly anticipate and recognize the Day 2 market changes which OTP made to the FCA thereby allowing OTP to keep the margins for its shareholders?

5. Should Schedule 16 and 17 charges and uplift and RSG charges be recovered through base rates rather than in the FCA. If the answer is yes, should the Company be allowed deferred accounting for all refunded and otherwise unrecovered Schedule 16 and 17, Uplift and RSG charges until its next rate case?

6. Should OTP be required to report for its ND operations to the Commission and to retail C&I customers signing an NDA the same FCA and MISO information as it is required to report in Minnesota?

7. Should OTP be subject to the same constraints and other conditions such as 1) limitations on virtual trades and 2) assurances that retail customers first receive the benefit of low-cost, base-load generation that OTP accepted as part of the Minnesota Stakeholder Group Settlement and as adopted by the Minnesota Public Utilities Commission?

8. When FCA's vary significantly from FCA forecasts, should the deviations be explained and re-forecasts submitted?

9. Are hidden capacity costs being passed through the FCA that should be removed, and is this one of the areas to be investigated by an outside independent accounting firm?

10. Should OTP hedge against natural gas cost swings or make comparable hedges to mitigate Day 2 market volatility caused by natural gas price spikes, weather, generator outages and other cost causation factors?

11. As recommended by Staff in their report to the Commission and as recommended by the Large Industrials, should OTP be ordered to file a ND rate case as soon as practicable?

12. Referring to Large Industrial Interrogatories No. 30 and 40, did OTP make any rate adjustments or refunds to any Large Industrial Customers, including those served under special rate contracts, which were not given or offered to other customers in the class? If yes, what action should the Commission take to ensure fair and comparable treatment to customers not receiving the payments or refunds?

13. Large Industrials reserves the right to rebut any issues raised in OTP's rebuttal testimony regarding issues listed in the Commission's Notice of Hearing.



Fargo office 4334 18th Avenue S W
Suite 200, PO Box 9156
Fargo, ND
58106-9156
Fax 701-232-4108

Fergus Falls office 215 S Cascade Street
PO Box 496
Fergus Falls, MN
56538-0496
Fax 218-998-3165

1-866-410-8780 • www.ottertail.com

May 14, 2007

Reply to Fergus Falls office
Direct: 218-998-7108

VIA E-FILING AND FIRST CLASS MAIL

Illona Jeffcoat-Sacco
North Dakota Public Service Commission
600 E. Boulevard Avenue
Bismarck, ND 58505-0480

**Re: Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
NDPSC Case No. PU-05-131**



Dear Ms. Jeffcoat-Sacco:

Enclosed in the above-referenced matter are the original and seven (7) copies of the Direct Testimony of Bernadeen Brutlag, with Exhibit BCB-1, and the Direct Testimony of Pete Berthon, with Exhibit PB-1.

If you have any questions, please feel free to contact me at any time.

Sincerely,

Bruce Gerhardson
Associate General Counsel
BG/dm

Enclosures

c: Allen C. Hoberg
Thomas D. Kelsch
Mike Bradley
Jerry Lein
Chuck MacFarlane
Bernadeen Brutlag
Pete Berthon

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

OTTER TAIL CORPORATION) Case No. PU-05-131
COST OF FUEL ADJUSTMENT)
CLAUSE TARIFF)

DIRECT TESTIMONY OF BERNADEEN BRUTLAG

I. INTRODUCTION AND QUALIFICATIONS

- Q. Please state your name and business address.**
A My name is Bernadeen Brutlag My business address is 215 South Cascade Street,
Fergus Falls, MN 56538-0496
- Q. By whom are you employed and in what capacity?**
A I am employed by Otter Tail Corporation d/b/a Otter Tail Power Company (“Otter
Tail” or the “Company”) as Manager of Regulatory Services
- Q. Please summarize your qualifications and experience.**
A A summary of my education and professional experience is attached as Exhibit
BCB-1
- Q. For whom are you testifying?**
A I am testifying on behalf of Otter Tail
- Q. What is the purpose of your testimony in this proceeding?**
A I will respond to the testimony submitted by Mr Larry Schedin on behalf of a group
of Large Industrial customers with respect to his proposal that all wholesale margins

1 received by the Company since market startup of MISO Day 2 be refunded to Otter
2 Tail's retail customers through the fuel clause adjustment ("FCA")
3

4 **Q. Please summarize your testimony.**

5 A I will explain that:

- 6 • Granting Mr Schedin's request would reduce Otter Tail's 2005 earned return on
7 equity ("ROE") to approximately 5.8% and the Company's 2006 earned ROE to
8 a level of approximately 7.4%. Earned returns that low would be confiscatory
- 9 • In 2005 all but 15% of asset and non-asset based margins were credited to the
10 retail revenue requirement. In 2006, all asset-based margins were credited to the
11 retail revenue requirement. Non-asset based margins were treated as an
12 unregulated activity with an appropriate allocation of utility labor and overhead
13 expense, which reduced the regulated revenue requirement by that amount
- 14 • If the 2005 and 2006 wholesale margins were shifted from supporting the base
15 rate revenue requirement to provide a credit against the fuel cost revenue
16 requirement, an offsetting increase in base rates for 2005 and 2006 would be
17 required
- 18 • Shifting the 2005 and 2006 wholesale margins to act as a credit to the fuel cost
19 revenue requirement would be prohibited retroactive and single-issue
20 ratemaking

21
22 **II. DISCUSSION OF WHOLESALE MARGINS**

23
24 **Q Please briefly describe the types of wholesale transactions that are being**
25 **discussed in this case.**

26 A There are two types of wholesale transactions: asset-based and non-asset based.
27 Asset-based transactions are those that involve selling energy from Otter Tail's own
28 generating plants into the market when that energy is not needed to serve its retail
29 customers. Non-asset based transactions are those that are unrelated to either the
30 Company's retail obligations or the Company's own generation.

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Q. Mr. Schedin, on page 6 of his testimony, claims that retail customers did not benefit from wholesale trading margins that Otter Tail has achieved in recent years. Is this correct?

A No Retail customers have benefited for years because asset-based margins serve as an above-the-line retail revenue credit in Otter Tail's revenue requirements calculation Figure 1 shows the dollar amount of each type of wholesale activity and how it was treated for North Dakota revenue requirements

ND TREATMENT OF WHOLESALE MARGINS (ND SHARE = 40%)			
	Asset-based A/L	Non-asset A/L	Non-asset B/L
2003	\$3,424,010	\$2,503,814	\$1,059,298
2004	\$3,330,571	\$2,743,480	\$1,083,057
2005	\$4,628,566	\$5,545,863	\$1,795,488
2006	\$4,418,462	\$0	\$2,001,104

Figure 1

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Figure 2 below graphically shows the returns reported to North Dakota since 2003

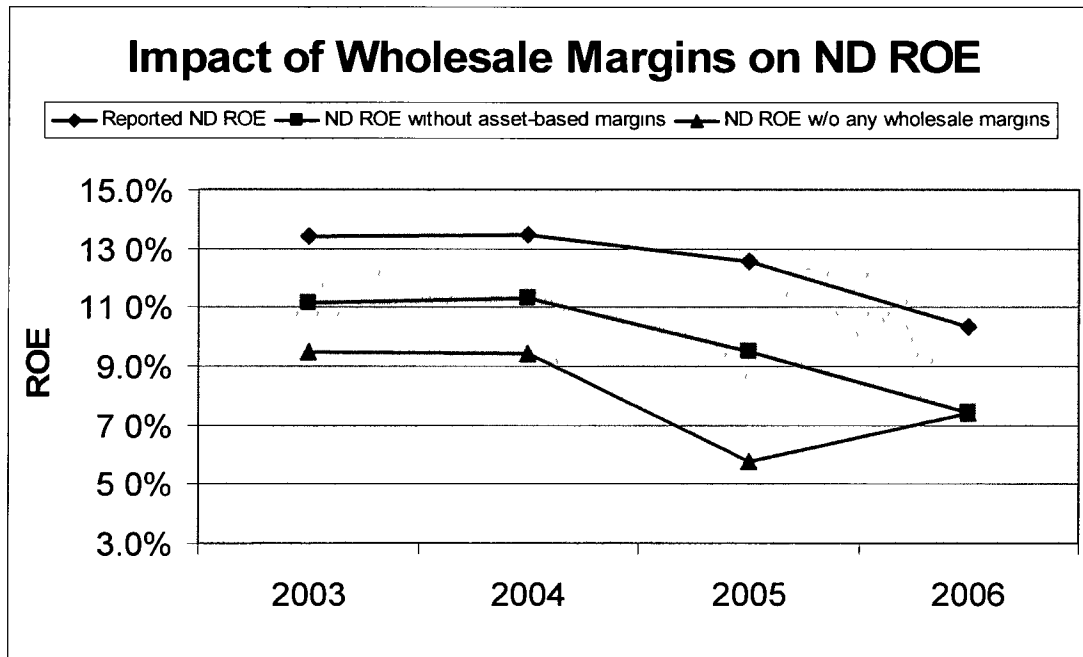


Figure 2

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1 If wholesale margins had been returned to customers through the fuel clause, this
2 contribution to earned return on equity would not have occurred and Otter Tail would
3 have been required to increase its base rates several years ago
4

5 **Q. Please explain Figure 2 in more detail.**

6 A The top line is the North Dakota earned return on equity (ROE) reported for 2003
7 through 2006 The middle line shows what the regulated ROE would have been if
8 asset-based margins had been passed through the fuel clause rather than used as a
9 revenue credit The bottom line in that graph shows what the ROE would have been
10 if asset-based margins had been passed through the FCA and all non-asset based
11 margins had been treated below the line
12

13 **Q. Why do the lines converge for 2006?**

14 A Otter Tail's PBR Plan expired at the end of 2005 With the expiration of the terms of
15 that Plan, Otter Tail began treating all non-asset based wholesale margins below the
16 line (which is how Otter Tail had been treating such margins in Minnesota and South
17 Dakota since 2001) ¹ Therefore, the bottom two lines of the graph converge in 2006
18 because reported 2006 ROE does not include any non-asset based margins The
19 purpose of Figure 2 is to show the historic contribution of both asset and non-asset
20 margins to regulated ROE In 2006, non-asset wholesale margins were not included
21 as a contribution to regulated ROE If the non-asset based margins had been above
22 the line in 2006, and if those margins were then passed through the fuel clause, Otter
23 Tail's earned ROE would have been lower as the allocated costs would have been
24 returned to above-the-line treatment with no offsetting revenues
25

¹ Prior to that time, a portion of non-asset based margins called "buy-resell" transactions had been credited above-the-line It should also be noted that along with moving those margins below the line, Otter Tail also assigned associated labor and overhead costs below the line, and thereby retail revenue requirements were reduced because of the shared labor and overhead expense removed from the regulated utility revenue requirement

1 **Q. What was the potential result under the PBR Plan if wholesale margins had been**
2 **treated differently?**

3 A Otter Tail’s PBR Plan included provisions that allowed Otter Tail to raise base rates
4 and/or collect an annual revenue deficiency from customers if Otter Tail’s earned
5 ROE fell below a certain level Without the contribution made by asset-based
6 wholesale margins, Otter Tail would have been eligible to raise its rates in 2005 under
7 the terms of the PBR Plan If both asset-based margins and the portion of non-asset
8 based margins included above the line had not been credited to the retail revenue
9 requirement, Otter Tail would have been eligible to raise its rates in each of the years
10 2003 through 2005 under the PBR Plan

11

12 **Q. What could have been the outcome in 2006 if asset-based margins had been**
13 **passed back to retail customers through the FCA?**

14 A Changing the treatment of asset-based wholesale margins from a retail revenue credit
15 to a credit against the FCA can only be done appropriately in a general rate case As
16 can be seen from Figure 2, if such a change had been made in 2006 without a change
17 in base rates, Otter Tail’s earned ROE would have been so low as to be confiscatory.

18

19 **Q. On page 6 of his testimony, Mr. Schedin states that “Non-asset based margins**
20 **are made possible by OTP trading staff members whose salaries and benefits are**
21 **paid for by retail customers.” Is this statement correct?**

22 A No Otter Tail has always fully allocated below the line all costs associated with
23 below-the-line activities. Consequently, the ratepayers have not paid for the cost of
24 these below-the-line activities

25

26 Figure 3 below provides North Dakota’s share of the salaries and overhead costs
27 assigned to below-the-line wholesale margins

28

2003	\$217,134
2004	\$298,483
2005	\$262,633
2006	\$719,741

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Figure 3

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Q. On page 6 of his testimony, Mr. Schedin states that “Because the present proceeding makes major changes to OTP’s FCA, the Settlement Agreement and Revised Performance-Based Ratemaking (PBR) Plan ... should not be used as a basis for utilizing trading margins for increasing OTP’s ROE.” Do you agree?

A No, I do not, for three reasons First, the PBR Plan contained a provision stating that the PBR Plan did not change the Company’s existing fuel clause adjustment mechanism That provision was adhered to throughout the period covered by the PBR Plan Second, as noted earlier in my testimony, under the PBR Plan, Otter Tail applied a portion of non-asset based wholesale margins above the line If the margins had instead been used to meet the fuel clause revenue requirement, Otter Tail would have been eligible to raise its rates under the terms of the Plan Third, the advent of the MISO energy market did not change the North Dakota FCA mechanism The North Dakota rule governing calculation of the FCA remains in effect and Otter Tail continues to calculate its monthly FCA in compliance with that rule

Q. Intervenors advocate refunding all wholesale margins since market startup (p. 11 of Mr. Schedin’s testimony). Is this a viable option for Otter Tail?

A First, as I have already explained, it would be inappropriate to retroactively reallocate the wholesale margins from the retail revenue requirement to the fuel clause revenue requirement without a corresponding increase in retail rates Second, this would require both a retroactive change in the terms of the PBR Plan, and a retroactive change in the treatment of wholesale margins after the end of the PBR Plan starting January 1, 2006. The Company has relied on the historical practice of allocating wholesale margins as a credit to base rates, and treating non-asset based activities as unregulated with an offsetting allocation of costs Consequently, the Company has foregone the ability to file for a rate increase in those prior periods The Company is entitled to have any change in the treatment of wholesale margins occur prospectively That, in turn, requires a rate case in order to determine the resulting retail rates

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The prohibition against retroactive ratemaking will be discussed in Otter Tail’s post hearing brief

Q. Interveners also argue that all future wholesale margins should be passed on to retail ratepayers via the FCA. Can Otter Tail agree to this position?

A No. Mr Schedin is advocating a change in the allocation of wholesale margins with no evidence that retail rates would remain reasonable In fact, as demonstrated by Figure 2, the Company would not be able to recover its cost of providing service if the wholesale margins ceased to provide a credit to the retail revenue requirement without a corresponding increase in retail rates Mr Schedin relies heavily on the treatment of wholesale margins in Minnesota The only Minnesota utilities that allocate wholesale margins to the fuel cost revenue requirement are Interstate Power and Light Company and Xcel Energy Both utilities began flowing wholesale margins through the fuel clause in their respective rate cases For example, Xcel Energy shifted its asset-based margins from supporting the retail revenue requirement to the fuel clause in the context of its 2005 electric rate case, Docket E-002/GR-05-1428 That change resulted in a \$16.2 million increase in Xcel Energy’s base rates. Mr Jeffrey Robinson, Xcel Energy’s financial witness, explained this in his Direct Testimony, at page 51, as follows

Historically, these margins have been used as an offset to the retail revenue requirement in the determination of cost of service. The Company is proposing to discontinue this treatment, and shift the benefit of these margins to the Company’s fuel recovery mechanism Rather than providing an offset to base rate revenue requirements, these margins are being proposed to provide a reduction to fuel cost recovery requirements. .. This adjustment results in a reduction to Minnesota jurisdictional Other Operating Revenue of \$16,196,000

1 Likewise for Otter Tail, crediting wholesale margins to the fuel cost revenue
2 requirement would necessarily require an increase in Otter Tail's base rates

3
4 That is why it is inappropriate to change rates based on consideration of a change in a
5 single cost or revenue. The inappropriateness of setting rates based on a change in a
6 single cost or revenue component is supported by the fact that within any 12-month
7 period there will be changes that are beneficial to the utility and changes that are not
8. Both need to be considered, and this is accomplished by using the test year concept in
9 a rate case, in which all revenues and expenses occurring within the test year are
10 considered when setting rates

11
12 The inappropriateness of setting rates based on a change in a single cost or expense
13 will be further discussed in Otter Tail's post evidentiary brief

14
15 **Q. Why is Otter Tail's request to pass the 32 charge types from MISO's Day 2**
16 **energy market through the FCA not single issue ratemaking?**

17 A The FCA allows utilities to recover the cost of purchased energy, fuel, delivered
18 losses, and congestion (in the form of redispatched units). When MISO implemented
19 the Day 2 energy market, we continued to incur those same costs, but the name, form
20 and means of calculating such costs and revenues changed. The charge types
21 instituted by MISO provide more granularity of costs but they do not change the basic
22 characteristics of the costs. When grouped and netted together, the retail portion of
23 the 32 MISO charge types represents the same types of costs identified in North
24 Dakota's rules for inclusion in the fuel clause adjustment

25
26 **III. CONCLUSION**

27
28 **Q. Please summarize your testimony**

29 A Shifting the wholesale margins credit from the Company's retail revenue requirement
30 to the fuel cost revenue requirement, without a corresponding increase in base rates,
31 would result in the Company having inadequate earnings (as demonstrated by the

1 resulting unacceptable earned return on equity in Figure 2) Consequently, any
2 change in how wholesale margins are recognized needs to occur in the context of a
3 general rate case, where all costs and revenues can be considered In a rate case
4 setting, it can be determined whether the asset-based margins should be credited to
5 the base rate revenue requirement or to the fuel cost revenue requirement If it is
6 determined that it is preferable to credit those margins to the fuel clause revenue
7 requirement, then a corresponding increase in base rates would be necessary In
8 addition, the alternatives for assuring that non-asset-based wholesale margin activities
9 are not subsidized can be fairly considered in the context of a general rate case

10

11 In the meantime, the ratepayers are not being harmed The Company continues to
12 credit the asset-based margins to its retail revenue requirement and to allocate costs
13 below the line with respect to its non-asset based activities There is no evidence that
14 this is resulting in unreasonable rates

15

16 **Q Does this conclude your testimony**

17 **A Yes it does**

18

Bernadeen Brutlag
Manager, Regulatory Services
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538-0496

EDUCATION

Bachelor of Science, Accounting
Moorhead State University (now Minnesota State University)
Moorhead, MN, 1984

EXPERIENCE AND CURRENT RESPONSIBILITIES

Depreciation Analyst, Accounting, 1984-1989 Responsible for conducting and obtaining approval for the results of depreciation studies required by regulatory commissions, primarily Minnesota

Senior Regulatory Analyst, Corporate Revenue Analysis, 1989-1993 Primary responsibility was preparing annual cost of service studies for the three state jurisdictions, and other regulatory and financial analysis

Manager of Regulatory Analysis and Compliance, 1993-1998 Primary responsibility was revenue requirements and financial analysis

Manager, Regulatory Services, 1998-current, with responsibility for the Company's revenue requirements, rate administration, regulatory compliance, rate design, load research, long-range forecasting, and overall regulatory policy

PROFESSIONAL ASSOCIATIONS

Certified Public Accountant (inactive), Minnesota

Member, Minnesota Society of Certified Public Accountants

Member, Institute of Management Accountants

TESTIMONY EXPERIENCE

Provided formal testimony in 2000 before the North Dakota Public Service Commission regarding Otter Tail's Performance-Based Ratemaking Plan Has appeared numerous times before the Commissions in Minnesota, North Dakota and South Dakota related to various miscellaneous issues and cases

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

OTTER TAIL CORPORATION)
COST OF FUEL ADJUSTMENT)
CLAUSE TARIFF)

Case No PU-05-131

DIRECT TESTIMONY OF PETE BEITHON

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A My name is Peter Beithon My business address is 215 South Cascade Street, Fergus Falls, MN 56538-0496

Q. By whom are you employed and in what capacity?

A I am employed by Otter Tail Corporation d/b/a Otter Tail Power Company (“Otter Tail” or the “Company”) as Manager, Regulatory Economics.

Q. Please summarize your qualifications and experience.

A I have a Bachelor of Science Degree from the University of North Dakota with majors in accounting and marketing and a minor in natural science I am a Certified Management Accountant (CMA) and a Certified Public Accountant (Inactive) I have worked for Otter Tail Power Company since November of 1983, starting as a property accountant in the Accounting Department, moving to the Treasury Department as the administrator of cash management, and have worked in the Regulatory Services Department since 1991 holding various capacities from regulatory analyst to Supervisor, Regulatory Economics I have held my current position of Manager, Regulatory Economics since April of 2005

1 **Q. For whom are you testifying?**

2 A I am testifying on behalf of Otter Tail

3

4 **Q. Please summarize your testimony in this proceeding?**

5 A My testimony responds to the testimony submitted by Mr Larry Schedin and Ms
6 Kavita Maim on behalf of a group of Large Industrial customers More specifically,
7 my testimony addresses the following

8 1 I explain that the monthly variability in Otter Tail's fuel clause adjustment
9 does not indicate either that the market is not working properly or that Otter Tail is
10 not properly managing its market participation. For example, the assertion that Otter
11 Tail should have less volatility than it does because 85% of its retail load is served by
12 coal plants ignores the fact that much of the variability seen by Otter Tail occurs
13 because its coal units are not always available and that delivered coal costs have seen
14 variability over the past 5 years

15 2 I explain that differences between monthly retail system energy
16 requirements and measured load are not an indication of a problem In my testimony
17 I demonstrate that the Intervenors have relied on a faulty analysis in asserting that the
18 hourly interval data, when compared to retail sales, demonstrates a potential problem
19 in either the market or Otter Tail's management

20

21 3 I explain that Schedule 16 and 17 charges should be recovered through the
22 fuel clause adjustment ("FCA") If the Commission determines that recovery of such
23 charges through base rates is more appropriate, the Company should be allowed
24 deferred accounting for all refunded and otherwise unrecovered Schedule 16 and 17
25 charges, and it should be allowed to recover such deferred charges in its next rate
26 case

27

28 4. I confirm that Otter Tail is not opposed to having North Dakota reporting
29 requirements similar to those in Minnesota, except that fuel cost adjustment ("FCA")
30 forecasts should be provided rather than forecasts of underlying costs Forecasted

1 cost information is not nearly as useful to customers as a forecasted FCA rate in
2 responding to anticipated electric costs

3
4 5 I also confirm that Otter Tail is not opposed to providing an explanation
5 when actual FCA costs and FCA forecasts differ significantly and to providing
6 updated forecasts when such differences occur

7
8 6 I explain that there are no hidden capacity costs being passed through the
9 FCA that should be removed

10
11 7. I explain why it does not make sense for Otter Tail to hedge its small
12 peaking plant against natural gas costs

13
14 8 Finally, my testimony confirms that Otter Tail supports the adoption of the
15 Staff's report

16
17
18 **II. OTTER TAIL'S FUEL COST VARIABILITY IS READILY EXPLAINABLE**
19 **AND JUSTIFIED**

20
21 **Q. Mr. Schedin asserts that Otter Tail's level of fuel cost volatility indicates either**
22 **that the market is not working properly or that Otter Tail is not properly**
23 **managing its market participation. Is he correct?**

24 A No As I will explain, the actual volatility was much less than identified by Mr
25 Schedin In addition, the volatility that has occurred resulted from three causes –
26 plant outages, coal delivery problems and price increases, and adjustments for
27 corrections by MISO None of these issues indicates either a problem with the
28 operation of the market or management by Otter Tail

29
30 **Q. Mr. Schedin states on page 5 of his testimony that the interveners' analysis,**
31 **which de-averages Otter Tail's FCA, shows swings as high as 300% of base**
32 **embedded fuel costs. Do you agree with the interveners' analysis?**

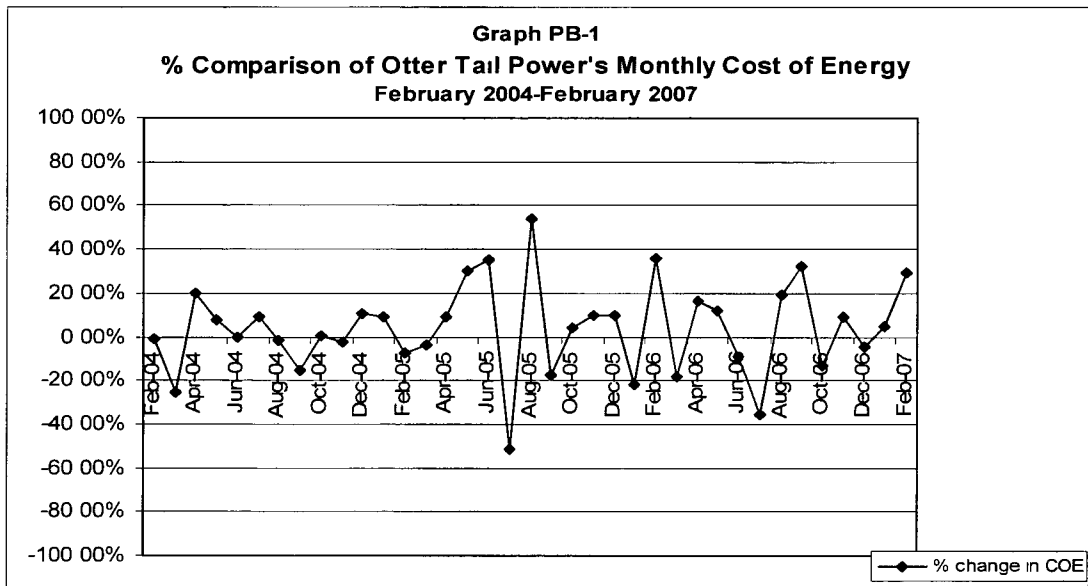
1 A. No The interveners' analysis appears to be intended to compare total cost of energy
2 to the base costs of energy set in Otter Tail's 1982 rate case There are two flaws in
3 their analysis Firstly, a volatility comparison should compare the total cost of energy
4 from month to month (or some other reasonably short duration comparison), not to
5 the much lower base cost of energy set over 20 years ago Comparing current energy
6 costs to the base costs set that long ago includes a great deal of gradual cost increase.
7 It does very little to show volatility
8
9 Secondly, Ms Maini states on page 6 of her testimony that she used the true-up
10 amount for each month by adding it to the energy charges Using the true-up as a cost
11 factor in this analysis is inappropriate This double counts costs already included in
12 prior months The true-up is only intended to address over- or under-collection of
13 costs It is not useful for determining the total fuel costs incurred in any particular
14 month In fact using it in this way would erroneously distort any analysis of costs
15 The true-up exists to address differences in consumption that may occur between
16 when costs are incurred and when those costs are included in customer bills (due to
17 temperature differences, etc) A simplified three-month example may help illustrate
18 the point if its cold and consumption is high in the first month (when costs are
19 incurred) but it warms and consumption is low in the next month (when the costs
20 from the previous month are being collected), then the FCA costs from the first
21 month will be under-collected because the adjustment will apply to fewer kWhs than
22 is necessary for full recovery If in the third month it gets cold and volumes are high
23 again, then the costs from the second month will be over-collected because the
24 adjustment amount will apply to more kWhs than is necessary for full recovery Over
25 several months the over-collections and under-collections will typically even out,
26 more or less The true up is used, as its name implies, to true up the amounts
27 collected over a longer period so that customers neither pay too much nor too little for
28 fuel costs incurred over that period The true-up is an effective tool for mitigating the
29 natural mismatch of volumes But adding the true up amount to the FCA amount as
30 Ms Maini does results in a double counting of costs That double counting results in

1 a distorted amplification in Ms Maim's analysis and therefore her conclusions are
2 based on this exaggeration.

3

4 **Q. Have you determined the actual degree of volatility experienced by Otter Tail?**

5 A. Yes I took the data supplied in IR 32-B and made a comparison of the cost of energy
6 from month-to-month A copy of Attachments 32-A and 32-B to IR 32 is attached to
7 my testimony as Exhibit PB-1 As you can see in Graph PB-1, there is variability, but
8 not to the degree Ms. Maim and Mr Schedin state in their testimony



9

10 The month-to-month comparison of the cost of energy indicates fluctuations from as
11 low as 4% to as high as slightly over 50% Remember, this is a measure of month-to-
12 month changes If a previous month is abnormally low, such as January 2006 when
13 Otter Tail returned over \$3 million dollars through the fuel clause as a result of
14 implementing new shadow settlement software (ND PSC staff notes this on page 10
15 of its report), then, as a result, normal February 2006 costs create what appears to be
16 an upward spike The graph also shows the increased costs from April 2005 to June
17 2005, which were due to wholesale energy purchases during the Big Stone plant
18 overhaul in 2005 Further, MISO had an error in reported costs related to market
19 start-up in July 2005 which was corrected in August 2005, and this error and
20 correction are reflected as an abrupt upward and then downward swing in those two

1 months In addition, my analysis, shown in Graph PB-1, reflects that as costs of
2 energy purchases and fuel rise due to basic supply and demand, fluctuations become
3 more pronounced These fluctuations are normal in commodity markets and the
4 FCA's very purpose is to accommodate these fluctuations

5
6 These fluctuations do not indicate that something is wrong with either the market or
7 Otter Tail's management of its fuel costs

8
9 **Q. Mr. Schedin, on page 5, infers that Otter Tail's FCA should be very stable**
10 **because 85 percent of the retail load is served by coal plants and that coal costs**
11 **have remained quite stable. Do you agree that 85% of the Company's retail**
12 **loads are met by coal plants??**

13 A No The analysis done by Ms Maini in table 1 on page 5 is too simplistic to be
14 meaningful Ms Maini only takes the total kWh sales for retail in a month and
15 divides that by the total generation in a month. This analysis ignores the variations of
16 Otter Tail's system requirements from hour to hour and does not consider outages

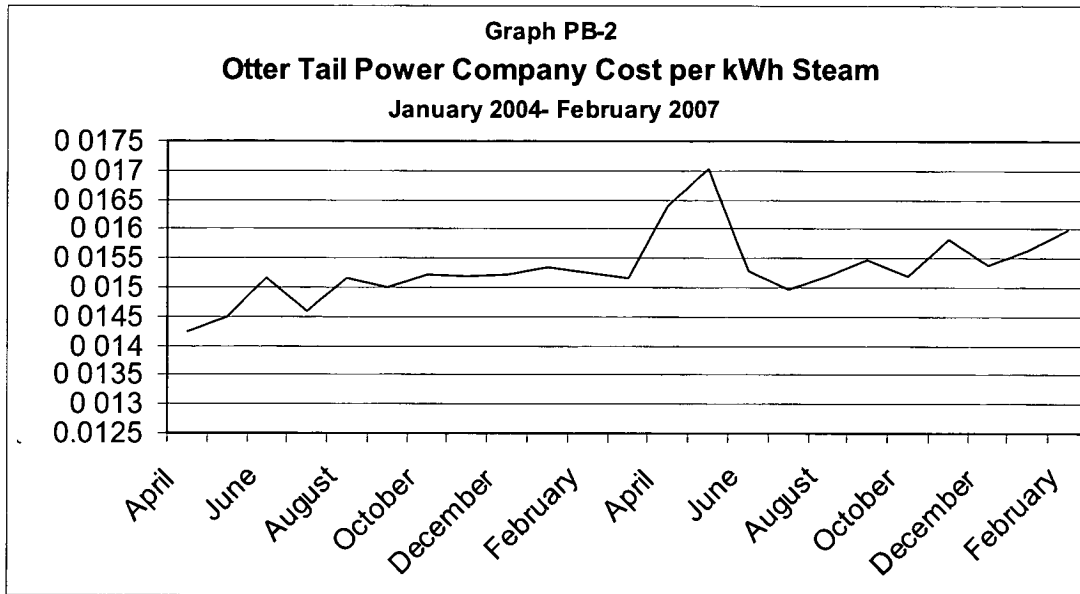
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18 Nor did her analysis consider the need to purchase power during peak and shoulder
19 periods Any electric system has higher requirements in peak and shoulder hours than
20 in off-peak hours The energy needs at peak and shoulder times often need to be met
21 with a combination of generation and purchased energy Ms Maini's analysis
22 inappropriately includes kWh which were actually used for asset-based sales made at
23 times when the energy was not needed for retail load This makes it appear there
24 were more kWh generated for retail load than actual were

25
26 The percent of retail load served by coal plants varies widely from less than 50%, at
27 peak times and during outages, to over 90% during non-peak times when all
28 generation is available

29

1 **Q. Do you agree that coal prices have been stable?**

2 A No While coal costs have been more stable than the cost of purchased energy and
3 some other fuel costs, such as natural gas and fuel oil, it is an overstatement to
4 suggest coal costs have not increased in recent years If one takes the average steam
5 costs from Otter Tail's FCA filings for the 12 months of 2000 and compares it to the
6 same information for the 12 months of 2006, the cost of fuel for steam generation has
7 risen 41% Using the information provided in Attachment 32-B to the Intervenor's
8 Interrogatory 32 (attached as Exhibit PB-1), my analysis shows a 15% increase in
9 steam generation costs when comparing the twelve month average for 2004 versus the
10 twelve month average for 2006 If one looks at the beginning of 2004 (January 2004)
11 and compares it to the end of 2006 (December) the change is 19.7%. By contrast,
12 Ms Maimi's analysis only looks at the one year of change from the 2005 average to
13 the 2006 average You can see the results are quite different even though my analysis
14 is only two years as compared to Ms Maimi's one-year analysis Picking a particular
15 period to highlight as the interveners have, can distort the results an analysis In
16 graphing out the cost per kWh for steam from the information provided in
17 Attachment 32-B, one can see in graph PB-2 that there was also significant volatility
18 in coal prices caused by the rail delivery problems in the spring of 2006 This
19 analysis demonstrates that Otter Tail's coal resources are not as insulated from cost
20 fluctuations as Intervenor's suggest While coal is generally available and has a
21 history of reasonably stable costs, coal is subject to price increases which can
22 contribute to FCA volatility



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Q. Do plant outages result in fuel clause volatility?

A For Otter Tail, the most significant cause of fuel clause volatility is curtailment of its base load plants, i.e. when a major plant is offline for overhaul (as the North Dakota Public Service Commission Staff discussed on the fourth page in its Staff Report dated December 8, 2006) or when unplanned outages occur frequently. Figure 3 of Ms. Mami's testimony has a spike in the April, May and June period of 2005. While the raw amounts she uses are exaggerated due her inclusion of the true-up amounts, as previously discussed, it is true that there was a relative spike in costs during that period. That spike was due to the overhaul of the Big Stone Plant, Otter Tail's largest resource. Similarly, the relative increase in costs in Ms. Mami's Figure 3 for May and June of 2006 was due to the fact that the Coyote generating plant, another of Otter Tail's significant resources, was offline during that period for its overhaul.

Increases in energy costs during these scheduled outages are understandable. Relatively expensive purchased power is required to replace the cheap power that is not available while the plant is being worked on. Increases during these periods don't reflect poor market performance or inadequate management by Otter Tail. They

1 reflect the perfectly appropriate need to maintain power plants Maintenance outages
2 cannot be avoided and, therefore, neither can increases in energy costs during those
3 outages

4

5 **Q. Explain how MISO adjustments result in FCA volatility?**

6 A. MISO adjustments are the largest factor in volatility in Otter Tail's fuel clause after
7 plant outages As the NDPSC staff noted on page 1 of its December 8, 2006 report,
8 Otter Tail has a unique multi-utility balancing area (control area). Only 30% of load
9 in the Otter Tail balancing authority is served by Otter Tail, the rest of the load is
10 served by other utilities Of those, half are MISO members and half are not This
11 complexity in the Otter Tail balancing area is significant because it creates large
12 monthly adjustments due to the fact that the utilities in the balancing area are
13 allocated MISO costs initially using estimated metering data which is later adjusted
14 based on actual data An example (noted by the NDPSC staff in its December 8,
15 2006 report on page 9) of the impact of a large adjustment happened last summer
16 (2006) when an entity significantly under-estimated its load for a couple of days
17 This made costs swing dramatically one direction in August and then again in the
18 other direction in September when actual metered data became available and the
19 corrections were recorded. Otter Tail reported the issue at that time and discussed it
20 with Commission Staff The question was whether to estimate the impact to reduce
21 the volatility and it was determined by staff (and also Minnesota Department of
22 Commerce Staff) not to attempt to estimate the impact of this error and use only the
23 actual MISO charges in the fuel clause NDPSC staff notes on page 10 of its
24 December 8, 2006 report that MISO adjustments continue as MISO continues to
25 resolve operational difficulties The longer the MISO Day 2 market operates, the
26 more Otter Tail expects MISO adjustments to become of smaller magnitude

27

28 **Q. Please respond to Mr. Schedin's claim, p 9, that the four-month average of fuel**
29 **costs hides volatility.**

30 A The four month average doesn't "hide" volatility It smoothes volatility consistent
31 with the North Dakota rules governing the FCA The fact that North Dakota rules for

1 the FCA use a four-month average would indicate that volatility has always been a
2 factor and consideration for the FCA. More importantly, using a four month average
3 minimizes the volatility in rates paid that would otherwise occur because of plant
4 outages, coal shortages, and the above-described MISO adjustments

5
6 **III. THE COMPARISON OF HOURLY INTERVAL DATA TO RETAIL SALES.**

7
8 **Q. Mr. Schedin, p. 5, relies on Ms. Maini's comparison of hourly interval data to**
9 **retail sales volumes and based on the differences concludes that either the**
10 **market is not working properly or that Otter Tail is not properly managing its**
11 **market participation? Is he correct?**

12 A. No. This assertion fails to take into consideration either the impact of plant outages
13 or MISO adjustments, as described above. In addition, the fuel clause does not use
14 hourly interval data for its volumes (the methodology relied upon by Ms. Maini in her
15 analysis). Instead, it uses generation and purchases plus *net* MISO retail kWh as
16 shown in Exhibit PB-1, Interrogatory response 32-B. Net MISO volumes include
17 adjustments. Consequently, Ms. Maini's analysis cannot be used to draw the
18 conclusions reached by Mr. Schedin.

19
20 **Q. On page 10 of Ms. Maini's testimony, she implies that because hourly load files**
21 **and the fuel clause are not the same "this could be a symptom of deeper**
22 **numerical errors." Is she correct?**

23 A. No. As I stated, the hourly load files and the fuel clause do not match for a number of
24 reasons, not the least of which is the MWH adjustments that happen each month due
25 to MISO.

26
27 **Q. Mr. Schedin at page 5, asserts that it may be necessary to have a major**
28 **accounting firm "review and correct" Otter Tail's market strategy and**
29 **accounting. Please respond.**

30 A. First, this suggestion appears to be based on Ms. Maini's flawed conclusion that it is
31 inappropriate for hourly load files and the fuel clause to be different. Second, North

1 Dakota Rule no 69-09-02-39 12 requires that Otter Tail's FCA be audited annually
2 and the report filed with the Commission This audit is conducted by Deloitte &
3 Touche, which, in addition to the work required for the regulatory report, spends
4 considerable time auditing fuel and purchased power costs for external financial
5 reporting purposes In addition, regulatory agencies in all three states in which Otter
6 Tail has service territory review our FCA each month. For each of these reviews,
7 Otter Tail's costs of energy are gathered on a total company basis so that each state's
8 review and analysis serves as a double-check (or triple-check) of accuracy to the
9 other states

10
11 Given the reviews that are already taking place, it would not be helpful or appropriate
12 to have one more review as Mr Schedin suggests

13
14 **Q. Mr. Schedin on page 5 accuses Otter Tail of charging costs without offsetting**
15 **benefits to retail customers. Please respond.**

16 A That assertion was based on the analysis performed by Ms Mami in which she
17 inappropriately assumes hourly load data kWh and the kWh used on the fuel clause
18 calculation should be the same The relevant information is provided as part of
19 Exhibit PB-1, Interrogatory response 32-A, which shows both costs and benefits,
20 based on both the MISO revenues and expenses for retail, as provided by the MISO
21 detail schedule filed each month with the fuel clause calculation

22
23 **Q. Mr. Schedin accuses Otter Tail of entering the market unprepared because it did**
24 **not conduct any of its own impact studies prior to market startup. Do you agree**
25 **that Otter Tail was unprepared?**

26 A No Mr Schedin bases this accusation on Otter Tail's response to Interrogatory No 7
27 which was:

28 *"INTERROGATORY NO 7 Has OTP conducted or participated in any*
29 *studies (both before and after the MISO Day 2 Market startup) showing*
30 *how OTP's retail customers and/or shareholders benefit from the MISO*
31 *Day 2 market? Please quantify any such benefits, and provide copies of*

1 *the studies **Response** No The only studies we are aware of were done*
2 *at the overall MISO level ”*

3 To infer from this response that Otter Tail was unprepared for the MISO Day 2
4 Market is wrong The following is a listing of the extensive preparations
5 undertaken by Otter Tail for the market:

- 6 • Otter Tail hired a consultant with senior level management skills from the
7 merchant function of a large utility which served loads in both the New England
8 ISO and PJM to assist in the overall market transition and strategy development
- 9 • Company representatives visited Public Service Electric and Gas in advance of
10 the market introduction to learn many concepts first-hand
- 11 • Otter Tail increased its staffing by hiring additional settlements personnel, a full-
12 time Financial Transmission Rights (FTR) Engineer and a Senior Bidding and
13 Generation Specialist from outside the Company with eastern LMP market
14 experience
- 15 • Otter Tail purchased and implemented OATI webTrader software to manage
16 MISO bid/offer entry and shadow settlements
- 17 • Otter Tail’s Power Services, Accounting and Regulatory areas worked
18 collaboratively to develop accounting and cost allocation methodologies for the
19 Market Then those methodologies were reviewed by an independent accounting
20 firm
- 21 • Otter Tail implemented accounting and allocation procedures through internally
22 developed, tested and audited software applications
- 23 • Otter Tail purchased the Promod LMP forecasting tool from New Energy
24 Associates to forecast LMP values before the market began both for FTR
25 planning purposes and overall strategy development

26

27 **IV. OTTER TAIL SHOULD BE ALLOWED TO RECOVER SCHEDULE 16 AND**
28 **17 COSTS.**

29

30 **Q. Why has the Company requested recovery of Schedule 16 and 17 charges**
31 **through the FCA?**

1 A Schedule 16 and 17 costs are legitimate costs imposed pursuant to a FERC-
2 approved wholesale tariff, which the Company is entitled to recover In Otter
3 Tail’s original petition in this docket it stated the following regarding schedules
4 16 and 17.

5 *“MISO will be assessing these non-transaction specific charges to all*
6 *Day 2 market participants to cover the costs of the new market Otter*
7 *Tail seeks FCA recovery because these FERC-approved rates are*
8 *assessed for the procurement of energy for its customers These costs*
9 *are generally assessed on an MWh basis and should be included in the*
10 *FCA.*

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

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

28 While the Minnesota Commission chose to recover Schedule 16 and 17 costs through
29 base rates, it recognized that these are legitimate and significant costs that the utilities
30 are entitled to recover Consequently, it allowed deferred accounting until a utility’s
31 next rate case or until December 20, 2009, whichever occurred first NDPSC staff

1 correctly recommends in its December 8, 2006 report (on page 3) continuing the
2 current FCA recovery process for Midwest ISO Day 2 Market costs, noting that
3 deferral would result in higher rates at the time of recovery. If the Commission
4 believes recovery of schedules 16 and 17 through base rates is preferable to fuel
5 clause recovery, it should either allow recovery in the FCA until the next rate case, or
6 it should allow deferred accounting until the next rate case

7
8 **V. OTTER TAIL DOES NOT OBJECT TO PROVIDING THE REQUESTED**
9 **FCA AND MISO INFORMATION WITH ONE MODIFICATION.**

10
11 **Q. Do you agree with Mr. Schedin's recommendation on page 6 of his testimony**
12 **that Otter Tail should provide its large Industrial customers and the**
13 **Commission with the same FCA and MISO information as the Company**
14 **provides in Minnesota?**

15 A Otter Tail does not object to providing that information, and in fact has been
16 providing forecasted FCA rates to all its customers, when requested, since 2004. We
17 do not support, however, providing the underlying cost projections, as is done in
18 Minnesota for two reasons. First, in Minnesota that cost information is correctly
19 treated as trade secret information, and it would be necessary to similarly obtain trade
20 secret protection for such information in North Dakota (which is much more difficult
21 to do). In addition, providing customers with Otter Tail's projection of its FCA rate
22 seems more useful. With an FCA rate, the customer can apply the rate to its expected
23 usage and determine the impact. In contrast, a cost breakdown does not translate
24 readily into a determination of the impact on a customer and therefore it would be
25 more difficult for a customer to determine how best to respond to the information

26
27 **Q. How often would the Company provide such forecasts?**

28 A We would not object to providing a 12-month forecast for each month, updated on a
29 quarterly basis if necessary

1 **VI. OTTER TAIL DOES NOT OBJECT TO PROVIDING ADDITIONAL**
2 **INFORMATION WHEN ACTUAL FCA COSTS DIFFER FROM**
3 **FORECASTS.**

4
5 **Q. Do you agree with Mr. Schedin that the Company should explain deviations**
6 **from its forecasts?**

7 A Otter Tail does not object to providing information on deviations to its North
8 Dakota customers on the same basis as it provides such information to its Minnesota
9 customers The Minnesota Order states "A utility shall update its FCA Forecast
10 whenever deviations from the current forecast are sufficiently material such that it
11 requires a reforecast for the next 12-month period The FCA Forecast shall be shared
12 with customer representatives who sign a protective agreement A copy of the
13 revised FCA forecast shall also be provided to the Department [of Commerce] Each
14 utility shall attempt to respond in a timely manner to questions from customers who
15 have signed a protective agreement "

16
17 **VII. THERE ARE NO HIDDEN CAPACITY COSTS BEING PASSED**
18 **THROUGH THE FCA.**

19
20 **Q. Are there hidden capacity costs being passed through Otter Tail's FCA as Mr.**
21 **Schedin implies on page 5 of his testimony?**

22 A No Otter Tail only includes energy purchases and fuel used for retail sales in the
23 FCA, as required by North Dakota rules The MISO Market is an energy market by
24 definition It is has not developed a capacity market

25
26 **VIII. OTTER TAIL SHOULD NOT HEDGE ITS NATURAL GAS PURCHASES.**

27
28 **Q. Could Otter Tail reduce volatility by hedging its natural gas purchases for its**
29 **Solway peaking generator as Mr. Schedin suggests on page 13 of his testimony?**

30 A No The very fact that Solway is a peaking unit makes it impractical to hedge the
31 natural gas purchases Predicting when and how long the plant will be run is difficult

1 at best Nor do the Solway fuel costs have a significant impact on Otter Tail's FCA
2 Solway was only 0.8% of Otter Tail's total generation in 2006

3
4 **IX. THE COMMISSION SHOULD ACCEPT THE STAFF REPORT**

5
6 **Q. Do you have any comments on the NDPSC staff's December 8, 2006 report on
7 Otter Tail's and the MISO Day 2 market?**

8 A. Yes In my opinion, the NDPSC staff report reflects a thorough understanding of the
9 MISO Day 2 market and its impacts on costs for Otter Tail Power Company Most of
10 the issues Mr. Schedin raises in his testimony were already discussed and explained
11 in the Staff's thorough review.

12
13 **Q. On page 14 of Mr. Schedin's testimony (item e.) he states "The Staff report also
14 indicates in Figures 4 and 5 that because of its extensive use of bilateral
15 contracts, OTP has little Market exposure to MISO purchases. This conclusion
16 is clearly misleading." Do you agree with Mr. Schedin's statement?**

17 A. Not with his statement that the report was misleading. Commission Staff was merely
18 indicating the price risk exposure for the purchases Otter Tail makes from the MISO
19 Day 2 market to serve its customers needs is relatively small It is worth noting
20 Figures 4 and 5 of the Staff's report do include purchases which aren't used for retail
21 In fact at the Commission's meeting on December 11, 2007, one or more of the
22 Commissioners requested a breakdown of energy and costs for retail only Exhibit
23 PB-2 shows graphs in two formats (for clarity) of Otter Tail's energy resource mix
24 and Otter Tail's energy supply costs by source The graph of costs with the line
25 format shows more clearly than does the stack area format graph that MISO costs
26 have gone negative at times due to the reasons I discussed above The area graph for
27 Otter Tail's energy resource mix shows clearly the small portion of supply that comes
28 from the MISO Market (other than the times there were corrections by MISO, again
29 as I've noted previously in my testimony) The purpose of Exhibit PB-2 is merely to
30 present the energy and costs on a retail only basis (the amounts that make up Otter
31 Tail's net energy and net energy costs for its FCA calculation)

1

2 **X. CONCLUSION**

3

4 **Q. Please summarize your testimony.**

5 A Fuel clause volatility results from a number of factors, none of which indicate either a
6 breakdown in the market or of Otter Tail Power's management. We are willing to
7 continue our current practice of providing, upon request, a twelve-month FCA
8 forecast for each month, updated when deviations become sufficiently material
9 Finally, the Commission should accept Staff's December 8, 2006, Report

10

11 **Q. Does this conclude your testimony?**

12 A Yes it does

13

**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 April 2005***

Line #	Charge Type	(A)	(B)	(C)	(D)	(E)	(F)	Charge types with MWH	
			Account	Retail Debits	Retail Credits	Net Intersystem	Total	MWH for Retail	
1	DA Mkt Admin Amt		555 0001	\$ 48,171 46	\$ -	\$ 11,782 23	\$ 59,953 69		
2	DA Asset Energy Amt		555 0002	\$ 12,022,267 39	\$ (9,922,737 04)	\$ (1,403,859 28)	\$ 695,671 07	281,048	(201,070)
3	DA FBT Congestion Amt		555 0003	\$ 3,000 00	\$ -	\$ 8,145 08	\$ 11,145 08		
4	DA FBT Loss Amt		555 0004	\$ 33,000 00	\$ -	\$ 106,333 54	\$ 139,333 54		
5	DA Congestion Rebate on COGA		555 0005	\$ -	\$ (10,951 63)	\$ -	\$ (10,951 63)		
6	DA Losses Rebate on COGA		555 0006	\$ -	\$ (110,736 47)	\$ -	\$ (110,736 47)		
7	DA Congestion Rebate on Option B GFA		555 0007	\$ -	\$ -	\$ -	\$ -		
8	DA Losses Rebate on Option B GFA		555 0008	\$ -	\$ -	\$ -	\$ -		
9	DA Non-asset Energy Amt		555 0009	\$ -	\$ (1,102,069 62)	\$ 626,359 69	\$ (475,709 93)	-	(23,058)
10	DA Revenue Sufficiency Guarantee Distribution Amt		555 0010	\$ 21,545 08	\$ -	\$ -	\$ 21,545 08		
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt		555 0011	\$ -	\$ -	\$ -	\$ -		
12	DA Virtual Energy Amt		555 0012	\$ 516,162 00	\$ -	\$ (408,180 43)	\$ 107,981 57		
13	FTR Mkt Admin Amt		555 0013	\$ 11,477 62	\$ -	\$ 2,468 46	\$ 13,946 08		
14	FTR Hourly Allocation Amt		555 0014	\$ -	\$ (158 91)	\$ 0 00	\$ (158 91)		
15	FTR Monthly Allocation Amt		555 0015	\$ -	\$ -	\$ -	\$ -		
16	FTR Transaction Amt		555 0016	\$ -	\$ -	\$ (33,030 79)	\$ (33,030 79)		
17	FTR Yearly Allocation Amt		555 0017	\$ -	\$ -	\$ -	\$ -		
18	RT Mkt Admin Amt		555 0018	\$ 3,242 52	\$ -	\$ 6,857 25	\$ 10,099 77		
19	RT Asset Energy Amt		555 0019	\$ (1,845,006 78)	\$ 1,160,924 71	\$ (965,271 11)	\$ (1,649,353 18)	41,550	(29,629)
20	RT FBT Congestion Amt		555 0020	\$ -	\$ -	\$ 14 65	\$ 14 65		
21	RT FBT Loss Amt		555 0021	\$ -	\$ -	\$ (6,402 43)	\$ (6,402 43)		
22	RT Congestion Rebate on COGA		555 0022	\$ 11 35	\$ -	\$ -	\$ 11 35		
23	RT Loss Rebate on COGA		555 0023	\$ -	\$ (58 82)	\$ -	\$ (58 82)		
24	RT Distribution of Losses Amt		555 0024	\$ -	\$ (300,146 82)	\$ -	\$ (300,146 82)		
25	RT Misc Amt		555 0025	\$ -	\$ -	\$ -	\$ -		
26	RT Non-Asset Energy Amt		555 0026	\$ -	\$ -	\$ 321,915 58	\$ 321,915 58		
27	RT Net Inadvertent Amt		555 0027	\$ -	\$ (16,778 24)	\$ -	\$ (16,778 24)		
28	RT Revenue Neutrality Uplift Amt		555 0028	\$ 111,270 59	\$ -	\$ -	\$ 111,270 59		
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt		555 0029	\$ 86,283 78	\$ -	\$ -	\$ 86,283 78		
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt		555 0030	\$ -	\$ -	\$ (90,081 05)	\$ (90,081 05)		
31	RT Uninstructed Deviation Amt		555 0031	\$ 57,152 05	\$ -	\$ -	\$ 57,152 05		
32	RT Virtual Energy Amt		555 0032	\$ -	\$ (482,273 00)	\$ 156,308 67	\$ (325,964 33)		
33	TOTAL FOR BOOK			\$ 11,068,577 05	\$ (10,784,985 83)	\$ (1,666,639 94)	\$ (1,383,048 72)	322,598	(253,757)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 283,591.22					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000								68,840,842
36	Cost per KWH					0.00412			

*April 2005 includes 27 days due to timing of settlement statements May will include the last 3 days of April, but be short days in May due to settlement statement timing

**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 May 2005***

Line #	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	555 0001 \$	47,768 88 \$	(743 70) \$	37,167 84 \$	84,193 02 \$		
2	DA Asset Energy Amt	555 0002 \$	9,372,267 78 \$	(7,690,272 33) \$	(339,552 63) \$	1,342,442 82 \$	322,701	(271,885)
3	DA FBT Congestion Amt	555 0003 \$	3,199 68 \$	- \$	1,852 74 \$	5,052 42 \$		
4	DA FBT Loss Amt	555 0004 \$	7,465 92 \$	- \$	56,470 57 \$	63,936 49 \$		
5	DA Congestion Rebate on COGA	555 0005 \$	- \$	- \$	(1,370 74) \$	(1,370 74) \$		
6	DA Losses Rebate on COGA	555 0006 \$	- \$	- \$	(52,058 21) \$	(52,058 21) \$		
7	DA Congestion Rebate on Option B GFA	555 0007 \$	- \$	- \$	- \$	- \$		
8	DA Losses Rebate on Option B GFA	555 0008 \$	- \$	- \$	- \$	- \$		
9	DA Non-asset Energy Amt	555 0009 \$	- \$	(604,717 30) \$	(218,356 60) \$	(823,073 90) \$	-	(16,654)
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 0010 \$	15,650 26 \$	- \$	15,767 71 \$	31,417 97 \$		
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 0011 \$	- \$	- \$	- \$	- \$		
12	DA Virtual Energy Amt	555 0012 \$	78,761 58 \$	- \$	(711,783 47) \$	(633,021 89) \$		
13	FTR Mkt Admin Amt	555 0013 \$	10,908 40 \$	- \$	209 84 \$	11,118 24 \$		
14	FTR Hourly Allocation Amt	555 0014 \$	- \$	(12,999 80) \$	(250 07) \$	(13,249 87) \$		
15	FTR Monthly Allocation Amt	555 0015 \$	- \$	(5,630 93) \$	(108 32) \$	(5,739 25) \$		
16	FTR Transaction Amt	555 0016 \$	- \$	4 12 \$	0 08 \$	4 20 \$		
17	FTR Yearly Allocation Amt	555 0017 \$	- \$	- \$	- \$	- \$		
18	RT Mkt Admin Amt	555 0018 \$	1,493 61 \$	- \$	8,400 47 \$	9,894 08 \$		
19	RT Asset Energy Amt	555 0019 \$	1,581,625 74 \$	(2,489,612 04) \$	(380,293 23) \$	(1,288,279 53) \$	57,965	(39,924)
20	RT FBT Congestion Amt	555 0020 \$	- \$	- \$	- \$	- \$		
21	RT FBT Loss Amt	555 0021 \$	- \$	- \$	- \$	- \$		
22	RT Congestion Rebate on COGA	555 0022 \$	- \$	- \$	- \$	- \$		
23	RT Loss Rebate on COGA	555 0023 \$	- \$	- \$	- \$	- \$		
24	RT Distribution of Losses Amt	555 0024 \$	- \$	(309,710 70) \$	- \$	(309,710 70) \$		
25	RT Misc Amt	555 0025 \$	- \$	- \$	- \$	- \$		
26	RT Non-Asset Energy Amt	555 0026 \$	- \$	- \$	900,706 34 \$	900,706 34 \$		
27	RT Net Inadvertent Amt	555 0027 \$	- \$	(36,088 69) \$	- \$	(36,088 69) \$		
28	RT Revenue Neutrality Uplift Amt	555 0028 \$	209,382 48 \$	- \$	- \$	209,382 48 \$		
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 0029 \$	188,203 44 \$	- \$	- \$	188,203 44 \$		
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 0030 \$	- \$	- \$	(55,553 04) \$	(55,553 04) \$		
31	RT Uninstructed Deviation Amt	555 0031 \$	61 52 \$	- \$	82 54 \$	144 06 \$		
32	RT Virtual Energy Amt	555 0032 \$	- \$	(57,014 76) \$	(458,786 60) \$	(515,801 36) \$		
33	TOTAL FOR BOOK		\$ 11,516,789 30	\$ (11,206,786 13)	\$ (310,003 18)	\$ (887,451 62)	380,666	(328,462)
34	Net MISO Charges for Retail = (C) 33 + (D)33		\$ 310,003.18					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000							52,204,199
36	Cost per KWH				0 00594			

*May 2005 includes 29 days due to timing of settlement statements (26 May & 3 from April)

** Includes MWH for losses at the high voltage

*** Includes amount billed to municipals and agencies as pass through (credit)

**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 June 2005***

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 45,716 26	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 16,601,169 01	\$ (13,900,584 59)			330,316	(278,219)
3	DA FBT Congestion Amt	5035 0003	0961		\$ (130 67)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 4,401 28	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ -				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ -				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ -	\$ (1,095,695 14)			-	(18,083)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 52,063 01	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -				
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 2,770 03	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ -	\$ (110,515 47)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (12 57)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ 33,565 32				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 4,913 85	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 1,169,121 63	\$ (1,949,327 70)			50,761	(29,799)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (374,185 06)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -				
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (38,709 49)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 273,843 26	\$ -				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 334,294 65	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 32,824 17	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 18,521,117 16	\$ (17,435,595 36)	\$ (3,923,130 52)	\$ (2,837,608 72)	381,077	(326,100)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 2,891,243 24					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000								54,976,412
36	Cost per KWH			\$ 0 05259					

	Net Retail	Net Intersystem	Total
MISO Book Totals	\$ 1,085,521 80		
June S55 & S14 adjustments	\$ 607,191 82		
May S55 and S14 adjustments	\$ 1,198,529 62		
Total MISO	\$ 2,891,243 24		

*June 2005 includes 29 days due to timing of settlement statements (27 May to June 23)

** Includes MWH for losses at the high voltage

*** Includes amount billed to municipalities and agencies as pass through (credit)

**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 July 2005***

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 60,500.69	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 22,342,280.79	\$ (19,169,347.39)			361,223	(320,338)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 98.87					
4	DA FBT Loss Amt	5035 0004	0961	\$ 144.65	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ -				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ -				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ -	\$ (709,243.75)			-	(7,154)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 32,169.94	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -				
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 3,729.95	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ -	\$ (291,247.10)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (611.27)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 5,383.56	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 2,490,788.99	\$ (2,920,808.76)			47,871	(40,098)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (707,605.64)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -				
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (111,259.03)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 361,188.47	\$ -				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 270,526.43	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ 2,338.67	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ -	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 25,569,151.01	\$ (23,910,122.94)	\$ (9,007,560.48)	\$ (7,348,532.41)	409,094	(367,590)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,659,028.07					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			41,504,369				41,504,369	
36	Cost per KWH			\$ 0.03997					

	Net MISO KWH		
	Net Retail	(adjusted cumulatively)	per kWh
MISO Book Totals	\$ 1,659,028.07	41,504,369	\$ 0.03997
May & June adjustments	\$ 941,271.62	116,955,796	\$ 0.00805
Total MISO	\$ 2,600,299.69	158,460,166	\$ 0.016410

*July 2005 includes 29 days due to timing of settlement statements (June 29 July 27)
 ** Includes MWH for losses at the high voltage
 *** Includes amount billed to municipalities and agencies as pass through (credit)

**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 August 2005**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt	5035 0001	0961	\$ 54,513 24	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 19,273,649 66	\$ (15,333,694 09)			330,898	(265,510)
3	DA FBT Congestion Amt	5035 0003	0961	\$ (770 80)	\$ -				
4	DA FBT Loss Amt	5035 0004	0961	\$ 5,000 04	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ -				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ -				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ -	\$ (926,177 44)			7,648	(18,915)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 22,029 80	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -				
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 9,451 64	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ -	\$ (260,818 69)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ -				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 2,955 98	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 1,083,861 66	\$ (1,512,064 53)			20,397	(28,690)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (539,729 37)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -				
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (76,975 44)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 364,020 60	\$ -				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 196,948 72	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 4,977 40	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 21,016,637 93	\$ (18,649,459 56)	\$ (10,255,555 89)	\$ (7,888,377 52)	358,943	(313,115)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 2,367,178 37					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			45,828,548					45,828,548
36	Cost per KWH			\$ 0 05165					

	Net MISO KWH				
	Net Retail	(adjusted cumulatively)	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 2,367,178 37	45,828,548			
June & July adjustments	\$ 168,936 51	3,793,658			
Total MISO	\$ 2,536,114 89	49,622,207			

** Includes MWH for losses at the high voltage

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 September 2005**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 30,093 17	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 14,055,946 78	\$ (12,143,731 63)			284,759	(239,953)
3	DA FBT Congestion Amt	5035 0003	0961	\$ (12,401 06)	\$ -				
4	DA FBT Loss Amt	5035 0004	0961	\$ 291,629 99	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 11,291 44	\$ -				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (143,498 86)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 511,130 13	\$ (1,526,056 60)			9,686	(22,174)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 10,588 92	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -				
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 6,912 95	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 11,317 74	\$ -				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ -				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 932 30	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 820,234 60	\$ (1,972,541 51)			32,273	(23,369)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ 0 90				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (267,592 90)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -				
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (41,260 78)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 255,726 12	\$ -				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 247,625 40	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 701 89	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 16,241,730 36	\$ (16,094,681 39)	\$ (7,509,379 43)	\$ (7,362,330 46)	326,718	(285,496)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 147,048 97					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			41,221,998				41,221,998	
36	Cost per KWH			\$ 0.00357					

MISO Book Totals	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 147,048 97			41,221,998
Adjustments made in August by MISO	\$ 581,397 41			5,768,344
Total MISO	\$ 728,446 38			46,990,343

** Includes MWH for losses at the high voltage

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 October 2005**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 24,340 79	\$ -			
2	DA Asset Energy Amt	5035 0002	0961	\$ 14,188,065 24	\$ (12,139,398 90)			309,213 (260,839)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 10,133 23	\$ -			
4	DA FBT Loss Amt	5035 0004	0961	\$ 233,777 06	\$ -			
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -			
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -			
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ (9,939 55)			
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (115,010 80)			
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 529,534 44	\$ (1,217,736 54)			10,850 (18,919)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 15,973 81	\$ -			
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -			
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 4,104 50	\$ -			
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 11,372 34	\$ -			
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (19,823 64)			
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ 19,145 56			
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -			
18	RT Mkt Admin Amt	5035 0018	0961	\$ 429 23	\$ -			
19	RT Asset Energy Amt	5035 0019	0961	\$ 2,178,939 67	\$ (2,418,114 37)			26,805 (51,259)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -			
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -			
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -			
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -			
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (229,785 85)			
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -			
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -			
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (8,691 96)			
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 329,324 08	\$ -			
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 244,352 16	\$ -			
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -			
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 7,058 03	\$ -			
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -			
33	TOTAL FOR BOOK			\$ 17,777,404 58	\$ (16,139,356 06)	\$ (14,062,690 11)	\$ (12,424,641 58)	346,868 (331,018)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,638,048 53				
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000							15,850,354
36	Cost per KWH			\$ 0.10334				

MISO Book Totals	Net MISO KWH				
	Net Retail	(adjusted cumulatively)	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 1,638,048 53	15,850,354			
Adjustments made in September by MISO	\$ 834,177 68	6,000.436			
Total MISO	\$ 2,472,226 21	21,850,790			

** Includes MWH for losses at the high voltage

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 November 2005**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 39,661 65	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 13,133,583 35	\$ (11,129,196 00)			353,999	(271,732)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 61,728 63	\$ -				
4	DA FBT Loss Amt	5035 0004	0961	\$ 225,213 59	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ (58,774 61)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (111,031 96)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 496,308 46	\$ (1,022,942 85)			12,426	(18,489)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 18,501 97	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -				
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 6,021 93	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 39,806 35	\$ (69,201 40)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (2,635 32)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 1,965 92	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 825,133 02	\$ (828,767 22)			18,543	(35,519)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (246,367 85)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -				
27	RT Net Inadvertent Amt	5035 0027	0961	\$ -	\$ (26,987 57)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 183,257 01	\$ -				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 275,031 68	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 1,190 50	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 15,307,404 04	\$ (13,495,904 78)	\$ (6,946,277 94)	\$ (5,134,778 68)	384,969	(325,739)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,811,499 26					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			59,229,227				59,229,227	
36	Cost per KWH			\$ 0 03058					

MISO Book Totals	Net MISO KWH				
	Net Retail	(adjusted cumulatively)	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 1,811,499 26	59,229,227			
Adjustments made in September by MISO	\$ 333,123 05	4,442,224			
Total MISO	\$ 2,144,622 31	63,671,452			

** Includes MWH for losses at the high voltage

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 December 2005* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 37,082 21	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 38,223,904 74	\$ (27,766,523 95)			488,375	(364,327)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 151,739 70	\$ (1,440 12)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 413,859 68	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 251 10	\$ (148,018 52)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (204,344 71)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 1,137,587 72	\$ (2,186,456 66)			15,334	(22,602)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 72,268 40	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 3,842 16	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 182,237 79	\$ (105,039 67)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (10,228 39)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 3,575 65	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 399,484 67	\$ (3,419,400 00)			7,438	(47,584)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ 2,883 22	\$ (340,317 33)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 3,100,121 35	\$ (3,127,529 09)			37,941	(38,198)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 0 72	\$ (43,631 64)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 100,802 25	\$ (6,346 04)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 275,534 98	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 5,089 67	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 44,110,266 01	\$ (37,359,276 12)	\$ (7,820,201 80)	\$ (1,069 211 91)	549,088	(472,711)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 6,750,989 89					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			76,376,860					76,376,860
36	Cost per KWH			\$ 0 08839					

* covers time period of 11-280to 12-26-05 ** increased for losses of 2 8%

MISO Book Totals	Net MISO KWH			
	Net Retail	(adjusted cumulatively)	per kWh	Net Intersystem Total
	\$ 6,750,989 89	76,376,860		
December Adjustments	\$ 138,949 05	5,768,257		
Total MISO	\$ 6,889,938 94	82,145,117		

NOTE a virtual transaction was done in error for the resource book This summary moved the costs in to the dealing book

	277,930 50
	207,637 50
Amount moved to dealing book	(70,293 00)

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 January 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 38,986 48	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 18,592,879 80	\$ (14,499,144 96)			483,442	(383,767)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 27,101 12	\$ (13,990 60)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 248,270 74	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 11,775 92	\$ (24,478 48)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (122,277 85)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 613,263 65	\$ (1,155,066 87)			16,477	(26,126)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 73,449 75	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 2,556 65	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 33,513 98	\$ (48,110 43)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (6,681 17)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 5,046 93	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 256,285 51	\$ (1,183,758 07)			7,370	(31,036)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (207,056 30)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,747,212 25	\$ (3,369,447 11)			41,173	(86,663)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 1,316 58	\$ (31,810 43)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 42,654 68	\$ (8,111 85)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 63,315 74	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 82 63	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 21,757,712 41	\$ (20,669,934 12)	\$ (4,221,545 28)	\$ (3,133,766 99)	548,462	(527,592)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,087,778 29					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			20,870,190					20,870,190
36	Cost per KWH			\$ 0 05212					

* covers time period of 11-28to 12-26-05 ** increased for losses of 2 8%

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 1,087,778 29	20,870,190		
2005 Otter Tail adjustments	\$ (3,138,373 26)			
December Adjustments	\$ 12,854 68	2,069,321		
Total MISO	\$ (2,037,740 29)	22,939,511		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 February 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 54,978 64	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 17,914,113 45	\$ (14,675,337 33)			454,036	(388,593)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 27,761 28	\$ (16,802 36)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 252,199 48	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 12,751 44	\$ (23,390 96)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (124,279 49)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 634,650 83	\$ (1,031,789 05)			16,229	(22,509)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 34,051 12	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 5,202 87	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 54,020 09	\$ (42,718 43)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (2,294 02)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 5,400 70	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 567,995 36	\$ (342,740 79)			18,156	(7,530)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (254,241 18)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,687,293 03	\$ (3,041,074 78)			38,738	(69,989)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 1,280 44	\$ (15,586 45)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 38,156 53	\$ (7,099 83)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 69,331 85	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 997 25	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 21,360,184 36	\$ (19,577,354 67)	\$ (3,429,789 63)	\$ (1,646,959 94)	527,158	(488,621)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,782,829 69					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			38,537,183					38,537,183
36	Cost per KWH			\$ 0 04626					
				Net MISO KWH					
				(adjusted					
				cumulatively)					
				Net Retail	per kWh	Net Intersystem	Total		
MISO Book Totals				\$ 1,782,829 69	38,537,183				
December Adjustments				\$ 738,697 85	13,218,000				
Total MISO				\$ 2,521,527 54	51,755,183				

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 March 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 45,704 14	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 15,044,231 03	\$ (13,150,212 44)			422,216	(378,097)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 23,681 70	\$ (13,680 24)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 272,854 18	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 10,479 20	\$ (20,246 54)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (134,475 34)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 554,303 87	\$ (960,998 24)			14,056	(22,713)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 17,288 54	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ (11,518 40)				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 3,746 23	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 45,831 66	\$ (57,599 06)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (5,771 73)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 1,879 28	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 294,899 80	\$ (181,402 51)			8,537	(5,463)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (170,479 91)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,631,374 71	\$ (1,759,098 67)			36,768	(38,790)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 8,933 25	\$ (2,735 41)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 100,695 10	\$ (10,058 18)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 39,744 30	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 269 73	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 18,095,916 72	\$ (16,478,276 67)	\$ (2,087,484 54)	\$ (469,844 49)	481,578	(445,062)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,617,640 05					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			36,515,828					36,515,828
36	Cost per KWH			\$ 0 04430					

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 1,617,640 05	36,515,828		
March Adjustments	\$ 507,259 51	11,391,357		
Total MISO	\$ 2,124,899 56	47,907,185		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 April 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 40,046 34	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 9,946,173 97	\$ (7,529,479 74)			289,399	(222,041)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 7,766 55	\$ (3,874 59)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 99,883 58	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 3,069 15	\$ (7,077 57)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (46,723 12)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 426,214 72	\$ (1,733,968 82)			12,230	(46,003)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 24,349 81	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 4,655 89	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 33,915 62	\$ (28,413 56)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (6,572 30)				
16	FTR Transaction Amt	5035 0016	0961	\$ 15,993 60	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 3,519 53	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 1,397,185 26	\$ (229,004 79)			33,465	(6,138)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (107,627 72)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,331,937 08	\$ (1,318,197 80)			32,177	(31,916)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 4,023 40	\$ (3,948 50)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 37,094 92	\$ (8,965 85)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 53,616 85	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 372 76	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 13,429,819 03	\$ (11,023,854 36)	\$ (1,658,125 25)	\$ 747,839 42	367,272	(306,098)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 2,405,964 67					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			61,173,956					61,173,956
36	Cost per KWH			\$ 0 03933					

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 2,405,964 67	61,173,956		
April Adjustments	\$ 2,833 99	6,479,831		
Total MISO	\$ 2,408,798 66	67,653,787		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 May 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 37,784 54	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 9,981,482 53	\$ (5,998,614 25)			269,081	(165,634)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 208 02	\$ (89 08)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 2,575 66	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ -				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ -				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 445,745 29	\$ (3,191,087 06)			12,605	(102,302)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 15,710 16	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 5,107 45	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 25,375 81	\$ (58,321 97)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (4,683 68)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 2,711 48	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 471,622 83	\$ (427,718 39)			13,273	(13,349)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (142,245 43)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,648,936 83	\$ (1,410,171 14)			44,303	(35,355)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 4,785 88	\$ (4,442 91)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 58,652 48	\$ (7,001 86)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 30,826 71	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 211 44	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 12,731,737 11	\$ (11,244,375 77)	\$ (661,880 04)	\$ 825,481 30	339,262	(316,641)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 1,487,361 34					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			22,621,387					22,621,387
36	Cost per KWH			\$ 0 06575					

* covers time period of 4-27 to 5-26-06 ** increased for losses of 2 8%

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 1,487,361 34	22,621,387		
May Adjustments	\$ 180,044 56	5,602,549		
Total MISO	\$ 1,667,405 90	28,223,935		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 June 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 28,673 10	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 15,640,546 12	\$ (11,558,049 24)			371,595	(276,373)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 10,521 37	\$ (6,498 25)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 160,478 21	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 3,376 43	\$ (7,279 31)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (78,832 61)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 422,099 43	\$ (3,376,568 66)			9,912	(80,737)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 16,593 83	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ (7,586 30)				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 1,589 51	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 37,385 62	\$ (42,772 45)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (2,488 81)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 2,688 53	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 872,416 77	\$ (1,229,053 88)			18,528	(37,103)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ 1,480 52	\$ (146,918 39)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,512,145 21	\$ (1,521,439 77)			34,109	(34,287)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 3,353 44	\$ (12,264 30)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 60,430 90	\$ (3,812 01)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 69,825 13	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 778 97	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 18,844,383 09	\$ (17,993,563 98)	\$ (4,618,078 81)	\$ (3,767,259 70)	434,145	(428,500)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 850,819 11					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			5,644,355					5,644,355
36	Cost per KWH			\$ 0 15074					

* covers time period of 5-27 to 6-27-06 ** increased for losses of 2 8%

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ 850,819 11	5,644,355		
June Adjustments	\$ (148,645 19)	6,618,137		
Total MISO	\$ 702,173 92	12,262,492		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 July 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 41,167 88	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 22,086,200 61	\$ (20,490,566 68)			390,117	(369,784)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 38,579 70	\$ (14,027 03)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 322,256 18	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 10,247 82	\$ (35,329 22)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (157,823 41)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 612,972 41	\$ (1,211,928 05)			10,872	(19,117)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 23,204 47	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 4,550 61	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 65,715 77	\$ (42,170 39)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (2,134 23)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 3,982 57	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 328,251 01	\$ (3,012,774 48)			5,925	(52,520)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (283,317 49)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,754,348 20	\$ (1,731,486 34)			29,742	(29,497)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 11,773 47	\$ (22,429 11)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 84,993 77	\$ (875 04)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 91,042 52	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 2,077 74	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 25,481,364 73	\$ (27,004,861 47)	\$ (2,030,788 85)	\$ (3,554,285 59)	436,656	(470,918)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ (1,523,496 74)					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			(34,261,938)					(34,261,938)
36	Cost per KWH			\$ 0 04447					

* covers time period of 5-27 to 6-27-06 ** increased for losses of 2 8%

	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
MISO Book Totals	\$ (1,523,496 74)	(34,261,938)		
July Adjustments	\$ 278,642 13	288,528		
Total MISO	\$ (1,244,854 61)	(33,973,410)		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 August 2006* Includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 44,035 08	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 28,181,455 36	\$ (25,951,834 04)			429,663	(411,613)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 72,370 26	\$ (4,702 03)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 468,846 80	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 2,607 15	\$ (69,287 96)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (231,539 33)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 758,305 17	\$ (1,748,151 43)			11,317	(23,232)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 17,022 56	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ (2,079 21)				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 3,187 30	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 46,698 89	\$ (165,473 08)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (30,583 65)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 3,112 41	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 513,135 82	\$ (2,293,056 22)			6,161	(39,776)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (303,301 13)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 2,325,866 24	\$ (2,297,451 07)			35,615	(34,549)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 10,895 78	\$ (9,968 06)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 83,016 52	\$ (16,787 84)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 335,827 28	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 934 10	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 32,867,316 72	\$ (33,124,215 05)	\$ 3,168,738 25	\$ 2,911,839 92	482,756	(509,170)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ (256,898 33)					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			(26,414,104)					(26,414,104)
36	Cost per KWH			\$ 0 00973					

* covers time period of 6-28 to 7-26-06 ** increased for losses of 2 8%

	Net MISO KWH			
	Net Retail	(adjusted cumulatively)	per kWh	Net Intersystem
MISO Book Totals	\$ (256,898 33)	(26,414,104)		
August Adjustments	\$ 542,570 44	17,968,805		
Total MISO	\$ 285,672 11	(8,445,300)		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 September 2006* includes any adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Net Intersystem	(F) Total	(G)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ 33,619 30	\$ -				
2	DA Asset Energy Amt	5035 0002	0961	\$ 12,843,246 98	\$ (11,601,274 40)			377,299	(352,028)
3	DA FBT Congestion Amt	5035 0003	0961	\$ 28,450 49	\$ (4,095 94)				
4	DA FBT Loss Amt	5035 0004	0961	\$ 221,176 34	\$ -				
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -				
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ 1,373 10	\$ (25,152 22)				
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ (108,883 63)				
9	DA Non-asset Energy Amt	5035 0009	0961	\$ 308,516 48	\$ (907,130 74)			9,304	(22,461)
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 12,579 48	\$ -				
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -				
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -			0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ 4,287 42	\$ -				
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 40,636 17	\$ (26,164 14)				
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (14,557 52)				
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -				
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -				
18	RT Mkt Admin Amt	5035 0018	0961	\$ 2,020 54	\$ -				
19	RT Asset Energy Amt	5035 0019	0961	\$ 187,213 98	\$ (639,207 11)			8,606	(21,703)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -				
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -				
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -				
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -				
24	RT Distribution of Losses Amt	5035 0024	0961	\$ -	\$ (169,690 70)				
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -				
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ 1,202,548 16	\$ (1,183,456 76)			33,194	(32,701)
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 2,299 50	\$ (9,300 77)				
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 51,870 58	\$ (269 56)				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 65,760 64	\$ -				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ 846 21	\$ -				
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -				
33	TOTAL FOR BOOK			\$ 15,006,445 37	\$ (14,689,183 49)	\$ (505,302 79)	\$ (188,040 91)	428,404	(428,893)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 317,261 88					
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000			(489,147)					(489,147)
36	Cost per KWH			\$ (0 64860)					

* covers time period of 8-27 to 9-26-06 ** increased for losses of 2 8%

MISO Book Totals	Net MISO KWH (adjusted cumulatively)			
	Net Retail	per kWh	Net Intersystem	Total
Adjustments	\$ 317,261 88	(489,147)		
Total MISO	\$ 2,901,506 46	39,798,529		

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**Otter Tail Power Company
 Detail of MISO Day 2 Charges
 September 2006 retail adjustments**

Line #	Charge Type	(A) Charge Type	(B) Account	(C) Retail Debits	(D) Retail Credits	(E) Total	(F)** Charge types with MWH for Retail	
1	DA Mkt Admin Amt ***	5035 0001	0961	\$ -	\$ -	\$ -		
2	DA Asset Energy Amt	5035 0002	0961	\$ -	\$ -	\$ -		
3	DA FBT Congestion Amt	5035 0003	0961	\$ -	\$ -	\$ -		
4	DA FBT Loss Amt	5035 0004	0961	\$ -	\$ -	\$ -		
5	DA Congestion Rebate on COGA	5035 0005	0961	\$ -	\$ -	\$ -		
6	DA Losses Rebate on COGA	5035 0006	0961	\$ -	\$ -	\$ -		
7	DA Congestion Rebate on Option B GFA	5035 0007	0961	\$ -	\$ -	\$ -		
8	DA Losses Rebate on Option B GFA	5035 0008	0961	\$ -	\$ -	\$ -		
9	DA Non-asset Energy Amt	5035 0009	0961	\$ -	\$ -	\$ -		
10	DA Revenue Sufficiency Guarantee Distribution Amt	5035 0010	0961	\$ 909 81	\$ (529 39)	\$ 380 42		
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0011	0961	\$ -	\$ -	\$ -		
12	DA Virtual Energy Amt	5035 0012	0961	\$ -	\$ -	\$ -	0	0
13	FTR Mkt Admin Amt	5035 0013	0961	\$ -	\$ -	\$ -		
14	FTR Hourly Allocation Amt	5035 0014	0961	\$ 175 77	\$ (0 12)	\$ 175 65		
15	FTR Monthly Allocation Amt	5035 0015	0961	\$ -	\$ (1 49)	\$ (1 49)		
16	FTR Transaction Amt	5035 0016	0961	\$ -	\$ -	\$ -		
17	FTR Yearly Allocation Amt	5035 0017	0961	\$ -	\$ -	\$ -		
18	RT Mkt Admin Amt	5035 0018	0961	\$ 14 62	\$ (1,396 38)	\$ (1,381 76)		
19	RT Asset Energy Amt	5035 0019	0961	\$ 2,820,696 12	\$ (32,708 84)	\$ 2,787,987 28	41,025	(737)
20	RT FBT Congestion Amt	5035 0020	0961	\$ -	\$ -	\$ -		
21	RT FBT Loss Amt	5035 0021	0961	\$ -	\$ -	\$ -		
22	RT Congestion Rebate on COGA	5035 0022	0961	\$ -	\$ -	\$ -		
23	RT Loss Rebate on COGA	5035 0023	0961	\$ -	\$ -	\$ -		
24	RT Distribution of Losses Amt	5035 0024	0961	\$ 15,161 55	\$ (61,990 22)	\$ (46,828 67)		
25	RT Misc Amt	5035 0025	0961	\$ -	\$ -	\$ -		
26	RT Non-Asset Energy Amt	5035 0026	0961	\$ -	\$ -	\$ -		
27	RT Net Inadvertent Amt	5035 0027	0961	\$ 1,333 21	\$ (16,351 49)	\$ (15,018 28)		
28	RT Revenue Neutrality Uplift Amt	5035 0028	0961	\$ 24,000 89	\$ (6,431 81)	\$ 17,569 08		
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	5035 0029	0961	\$ 12,246 50	\$ (170,884 15)	\$ (158,637 65)		
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	5035 0030	0961	\$ -	\$ -	\$ -		
31	RT Uninstructed Deviation Amt	5035 0031	0961	\$ -	\$ -	\$ -		
32	RT Virtual Energy Amt	5035 0032	0961	\$ -	\$ -	\$ -		
33	TOTAL FOR BOOK			\$ 2,874,538 47	\$ (290,293 89)	\$ 2,584,244 58	41,025	(737)
34	Net MISO Charges for Retail = (C) 33 + (D)33			\$ 2,584,244.58				
35	Net KWH for retail = ((H) 33 + (I) 33) * 1,000			40,287,676				40,287,676

** increased for losses of 2 8%

CORRECTED 12/21/06

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Otter Tail Power Company Detail of MISO Day 2 Charges October 2006* Includes any adjustments									
Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H) Charge types with MWH for Retail
1	DA Mkt Admin Amt	555 01	\$ 43 148 32	\$ -	\$ -	\$ 43 148 32			
2	DA Asset Energy Amt	555 02	\$ 18 008 677 00	\$ (16 581 162 91)	\$ -	\$ 1 427 714 09			391 619 (370 958)
3	DA FBT Congestion Amt	555 03	\$ 74,260 57	\$ (3,179 16)	\$ -	\$ 71,081 41			
4	DA FBT Loss Amt	555 04	\$ 242 042 49	\$ -	\$ -	\$ 242 042 49			
5	DA Congestion Rebate on COGA	555 05	\$ -	\$ -	\$ -	\$ -			
6	DA Losses Rebate on COGA	555 06	\$ -	\$ -	\$ -	\$ -			
7	DA Congestion Rebate on Option B GFA	555 07	\$ 1 773 30	\$ (72 821 20)	\$ -	\$ (71 047 90)			
8	DA Losses Rebate on Option B GFA	555 08	\$ -	\$ (118 567 53)	\$ -	\$ (118 567 53)			
9	DA Non-asset Energy Amt	555 09	\$ 531 128 29	\$ (1 107 088 67)	\$ -	\$ (575 960 38)			12 478 (21 617)
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 10	\$ 10 683 68	\$ -	\$ 1 181 53	\$ 11 865 21			
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 11	\$ -	\$ -	\$ -	\$ -			
12	DA Virtual Energy Amt	555 12	\$ -	\$ -	\$ -	\$ -			
13	FTR Mkt Admin Amt	555 13	\$ 4 900 59	\$ -	\$ -	\$ 4 900 59			
14	FTR Hourly Allocation Amt	555 14	\$ 50 352 83	\$ (75,492 07)	\$ 47 57	\$ (25 091 67)			
15	FTR Monthly Allocation Amt	555 15	\$ -	\$ (1,569 04)	\$ 9 06	\$ (1,559 98)			
16	FTR Transaction Amt	555 16	\$ -	\$ -	\$ -	\$ -			
17	FTR Yearly Allocation Amt	555 17	\$ -	\$ -	\$ -	\$ -			
18	RT Mkt Admin Amt	555 18	\$ 2 160 87	\$ -	\$ (275 48)	\$ 1 885 39			
19	RT Asset Energy Amt	555 19	\$ 689,350 24	\$ (440 031 25)	\$ 683 163 06	\$ 932 482 05			13 416 (10 134)
20	RT FBT Congestion Amt	555 20	\$ -	\$ -	\$ -	\$ -			
21	RT FBT Loss Amt	555 21	\$ -	\$ -	\$ -	\$ -			
22	RT Congestion Rebate on COGA	555 22	\$ -	\$ -	\$ -	\$ -			
23	RT Loss Rebate on COGA	555 23	\$ -	\$ -	\$ -	\$ -			
24	RT Distribution of Losses Amt	555 24	\$ -	\$ (309,957 38)	\$ 65 928 90	\$ (244 028 48)			
25	RT Misc Amt	555 25	\$ 55 28	\$ -	\$ -	\$ 55 28			
26	RT Non-Asset Energy Amt	555 26	\$ 1 684 297 74	\$ (1 616,017 31)	\$ -	\$ 68 280 43			35 997 (34 229)
27	RT Net Inadvertent Amt	555 27	\$ 1 463 80	\$ (9 806 74)	\$ 1,250 61	\$ (7,092 33)			
28	RT Revenue Neutrality Uplift Amt	555 28	\$ 43 726 32	\$ (2 581 67)	\$ (4,718 04)	\$ 36 426 61			
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 29	\$ 167 377 08	\$ -	\$ 26 524 12	\$ 193 901 20			
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 30	\$ -	\$ -	\$ -	\$ -			
31	RT Uninstructed Deviation Amt	555 31	\$ 286 03	\$ -	\$ (89 07)	\$ 196 96			
32	RT Virtual Energy Amt	555 32	\$ -	\$ -	\$ -	\$ -			
33	TOTAL FOR BOOK		\$ 21 555 884 43	\$ (20 338 274 93)	\$ 773,022.26	\$ 1,990,631 76	\$ 466 672 85	\$ 2 457 304 61	453 510 (436 938)
34	Net MISO Charges for Retail = (C) 33 + (D)33		\$ 1,217,609 50						
35	Net KWH for retail = ((G) 33 + (H) 33) 1 000		\$ 16 572 066						16,572,066
36	Cost per KWH		\$ 0 07347						
	* covers time period of 9 27 to 10-26-06 * increased for losses of 2 8%								
					Net MISO KWH (adjusted cumulatively)		per kWh	Net Intersystem	Total
	MISO Book Totals		\$ 1 217 609 50		16 572 066				
	October Adjustments		\$ 773 022 26		17 107 305				
	Total MISO		\$ 1,990,631 76		33,679,371				

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Otter Tail Power Company Detail of MISO Day 2 Charges November 2006* Includes any adjustments											
Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H) Charge types with MWH for Retail		
1	DA Mkt Admin Amt	555 01	\$ 62 835 42	\$ -	\$ -	\$ 62,835 42					
2	DA Asset Energy Amt	555 02	\$ 23 602 004 82	\$ (20 646 201 62)	\$ -	\$ 2,955,803 20			434,195	(399 063)	
3	DA FBT Congestion Amt	555 03	\$ 78 901 18	\$ (1 470 20)	\$ -	\$ 77 430 98					
4	DA FBT Loss Amt	555 04	\$ 274 955 44	\$ -	\$ -	\$ 274 955 44					
5	DA Congestion Rebate on COGA	555 05	\$ -	\$ -	\$ -	\$ -					
6	DA Losses Rebate on COGA	555 06	\$ -	\$ -	\$ -	\$ -					
7	DA Congestion Rebate on Option B GFA	555 07	\$ 1 280 64	\$ (78,825 87)	\$ -	\$ (77 545 23)					
8	DA Losses Rebate on Option B GFA	555 08	\$ -	\$ (134,535 04)	\$ -	\$ (134 535 04)					
9	DA Non-asset Energy Amt	555 09	\$ 492,786 87	\$ (1,375,563 88)	\$ -	\$ (882 777 01)			9 765	(21 524)	
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 10	\$ 23 904 27	\$ -	\$ (367 47)	\$ 23 536 80					
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 11	\$ -	\$ (515 29)	\$ -	\$ (515 29)					
12	DA Virtual Energy Amt	555 12	\$ -	\$ -	\$ -	\$ -					
13	FTR Mkt Admin Amt	555 13	\$ 4 863 59	\$ -	\$ -	\$ 4 863 59					
14	FTR Hourly Allocation Amt	555 14	\$ 61 162 33	\$ (113 277 41)	\$ 2 21	\$ (52 112 87)					
15	FTR Monthly Allocation Amt	555 15	\$ -	\$ (33 093 21)	\$ (0 92)	\$ (33 094 13)					
16	FTR Transaction Amt	555 16	\$ -	\$ -	\$ -	\$ -					
17	FTR Yearly Allocation Amt	555 17	\$ -	\$ -	\$ -	\$ -					
18	RT Mkt Admin Amt	555 18	\$ 4 042 88	\$ -	\$ (178 02)	\$ 3 864 86					
19	RT Asset Energy Amt	555 19	\$ 975 388 84	\$ (1 050 590 07)	\$ 196 805 98	\$ 121 604 75			17 452	(22 225)	
20	RT FBT Congestion Amt	555 20	\$ -	\$ -	\$ -	\$ -					
21	RT FBT Loss Amt	555 21	\$ -	\$ -	\$ -	\$ -					
22	RT Congestion Rebate on COGA	555 22	\$ -	\$ -	\$ -	\$ -					
23	RT Loss Rebate on COGA	555 23	\$ -	\$ -	\$ -	\$ -					
24	RT Distribution of Losses Amt	555 24	\$ -	\$ (402 339 36)	\$ 14 778 03	\$ (387 561 33)					
25	RT Misc Amt	555 25	\$ -	\$ -	\$ 97 63	\$ 97 63					
26	RT Non-Asset Energy Amt	555 26	\$ 1,756 786 05	\$ (1,756,786 05)	\$ -	\$ -			31,289	(31 289)	
27	RT Net Inadvertent Amt	555 27	\$ 2 830 22	\$ (12 085 36)	\$ (5,705 18)	\$ (14,960 32)					
28	RT Revenue Neutrality Uplift Amt	555 28	\$ 71 944 74	\$ (9 823 25)	\$ 17 959 20	\$ 80 080 69					
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 29	\$ 243 610 12	\$ -	\$ 85 007 62	\$ 328 617 74					
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 30	\$ -	\$ -	\$ -	\$ -					
31	RT Uninstructed Deviation Amt	555 31	\$ 2 300 98	\$ -	\$ -	\$ 2 300 98					
32	RT Virtual Energy Amt	555 32	\$ -	\$ -	\$ -	\$ -					
33	TOTAL FOR BOOK		\$ 27 659 598 39	\$ (25 615 106 61)	\$ 308,399 08	\$ 2,352,890 86	\$ (1 867 843 16)	\$ 485 047 70	492 701	(474 102)	
34	Net MISO Charges for Retail = (B) 33 + (C)33 + (D)33		\$ 2,352,890 86								
35	Net KWH for retail = (H) 33 + (H) 33 1,000		\$ 18,599,333						18,599,333		
36	Cost per KWH		\$ 0 12650								
	* covers time period of 10 27 to 11-26-06 * increased for losses of 2 8%										
			Net MISO KWH (adjusted cumulatively)								
MISO Book Totals			\$ 2 044 491 78	18 599 333							
November Adjustments			\$ 308 399 08	8 169 688							
Total MISO			\$ 2,352,890 86	26,769,020							

Public Document - Trade Secret Data Has Been Excised

Offer Tail Power Company Detail of MISO Day 2 Charges December 2006* Includes any adjustments									
Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H) Charge types with MWH for Retail
1	DA Mkt Admin Amt	555 01	\$ 62,128 46	\$ -	\$ -	\$ 62,128 46			
2	DA Asset Energy Amt	555 02	\$ 26,113,316 13	\$ (21,598,718 85)	\$ -	\$ 4,514,597 28			479 712 (415 265)
3	DA FBT Congestion Amt	555 03	\$ 143,164 67	\$ (155 94)	\$ -	\$ 143,008 73			
4	DA FBT Loss Amt	555 04	\$ 352,032 18	\$ -	\$ -	\$ 352,032 18			
5	DA Congestion Rebate on COGA	555 05	\$ -	\$ -	\$ -	\$ -			
6	DA Losses Rebate on COGA	555 06	\$ -	\$ -	\$ -	\$ -			
7	DA Congestion Rebate on Option B GFA	555 07	\$ -	\$ (140,945 13)	\$ -	\$ (140,945 13)			
8	DA Losses Rebate on Option B GFA	555 08	\$ -	\$ (173,434 05)	\$ -	\$ (173,434 05)			
9	DA Non-asset Energy Amt	555 09	\$ 734,937 40	\$ (1,509,732 07)	\$ -	\$ (774,794 67)			16 367 (23 527)
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 10	\$ 36,718 85	\$ -	\$ (704 45)	\$ 36,014 40			
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 11	\$ -	\$ -	\$ -	\$ -			
12	DA Virtual Energy Amt	555 12	\$ -	\$ -	\$ -	\$ -			
13	FTR Mkt Admin Amt	555 13	\$ 3,112 26	\$ -	\$ -	\$ 3,112 26			
14	FTR Hourly Allocation Amt	555 14	\$ 103,151 62	\$ (118,082 81)	\$ (20 63)	\$ (14,951 82)			
15	FTR Monthly Allocation Amt	555 15	\$ 69,553 17	\$ (20,552 42)	\$ (86 50)	\$ 48,914 25			
16	FTR Transaction Amt	555 16	\$ 248,619 00	\$ -	\$ -	\$ 248,619 00			
17	FTR Yearty Allocation Amt	555 17	\$ -	\$ -	\$ -	\$ -			
18	RT Mkt Admin Amt	555 18	\$ 2,888 11	\$ -	\$ (243 63)	\$ 2,644 48			
19	RT Asset Energy Amt	555 19	\$ 381,438 29	\$ (987,705 76)	\$ 517,700 30	\$ (88,567 17)			7 583 (22 762)
20	RT FBT Congestion Amt	555 20	\$ -	\$ -	\$ -	\$ -			
21	RT FBT Loss Amt	555 21	\$ -	\$ -	\$ -	\$ -			
22	RT Congestion Rebate on COGA	555 22	\$ -	\$ -	\$ -	\$ -			
23	RT Loss Rebate on COGA	555 23	\$ -	\$ -	\$ -	\$ -			
24	RT Distribution of Losses Amt	555 24	\$ -	\$ (381,476 83)	\$ 6,832 45	\$ (374,644 38)			
25	RT Misc Amt	555 25	\$ -	\$ -	\$ -	\$ -			
26	RT Non Asset Energy Amt	555 26	\$ 2,129,311 99	\$ (2,143,622 94)	\$ -	\$ (14,310 95)			39 796 (39 894)
27	RT Net Inadvertent Amt	555 27	\$ 6,642 16	\$ (8,686 58)	\$ (2,219 19)	\$ (4,263 61)			
28	RT Revenue Neutrality Uplift Amt	555 28	\$ 52,867 86	\$ (1,694 29)	\$ -	\$ 10,166 48			
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 29	\$ 142,929 27	\$ -	\$ 52,787 15	\$ 195,716 42			
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 30	\$ -	\$ -	\$ -	\$ -			
31	RT Uninstructed Deviation Amt	555 31	\$ 931 78	\$ -	\$ (1,181 84)	\$ (250 06)			
32	RT Virtual Energy Amt	555 32	\$ -	\$ -	\$ -	\$ -			
33	TOTAL FOR BOOK		\$ 30,583,743 20	\$ (27,084,807 67)	\$ 583,030 14	\$ 4,081,965 67	\$ (2,178,261 33)	\$ 1,903,704 34	543 458 (501 448)
34	Net MISO Charges for Retail = (B) 35+ (C) 35 + (D)35		\$ 4,081,965 67						
35	Net KWH for retail = ((G) 33 + (H) 33) 1 000		\$ 42,009 927						42,009,927
36	Cost per KWH covers time period of 11-27 to 12-27-06 * increased for losses of 2 8%		\$ 0 09717						
					Net MISO KWH (adjusted cumulatively)		per kWh	Net Intersystem	Total
	MISO Book Totals		\$ 3,498,935 53		42,009,927				
	December Adjustments		\$ 583,030 14		9,573,288				
	Total MISO		\$ 4,081,965 67		51,583,215				

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Otter Tail Power Company Detail of MISO Day 2 Charges January 2007* includes any adjustments										
Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H) Charge types with MWH for Retail	
1	DA Mkt Admin Amt	555 01	\$ 57,143.43	\$ -	\$ -	\$ 57,143.43				
2	DA Asset Energy Amt	555 02	\$ 21,940,485.43	\$ (16,127,195.78)	\$ -	\$ 5,813,289.65			467,466	(369,627)
3	DA FBT Congestion Amt	555 03	\$ 59,997.89	\$ (722.16)	\$ -	\$ 59,275.73				
4	DA FBT Loss Amt	555 04	\$ 247,337.27	\$ -	\$ -	\$ 247,337.27				
5	DA Congestion Rebate on COGA	555 05	\$ -	\$ -	\$ -	\$ -				
6	DA Losses Rebate on COGA	555 06	\$ -	\$ -	\$ -	\$ -				
7	DA Congestion Rebate on Option B GFA	555 07	\$ 59.84	\$ (57,970.49)	\$ -	\$ (57,910.65)				
8	DA Losses Rebate on Option B GFA	555 08	\$ -	\$ (121,468.40)	\$ -	\$ (121,468.40)				
9	DA Non-asset Energy Amt	555 09	\$ 833,410.01	\$ (1,258,360.13)	\$ -	\$ (424,950.12)				
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 10	\$ 29,230.67	\$ -	\$ (1,871.61)	\$ 27,359.06			20,215	(23,280)
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 11	\$ -	\$ (74.93)	\$ -	\$ (74.93)				
12	DA Virtual Energy Amt	555 12	\$ -	\$ (150,070.25)	\$ -	\$ (150,070.25)				
13	FTR Mkt Admin Amt	555 13	\$ 3,676.21	\$ -	\$ -	\$ 3,676.21				(6,142)
14	FTR Hourly Allocation Amt	555 14	\$ 41,662.65	\$ (342,234.91)	\$ (4.13)	\$ (300,576.39)				
15	FTR Monthly Allocation Amt	555 15	\$ -	\$ (1,662.68)	\$ 7.27	\$ (1,655.41)				
16	FTR Transaction Amt	555 16	\$ 316,130.75	\$ -	\$ -	\$ 316,130.75				
17	FTR Yearly Allocation Amt	555 17	\$ -	\$ -	\$ -	\$ -				
18	RT Mkt Admin Amt	555 18	\$ 4,437.76	\$ -	\$ (111.25)	\$ 4,326.51				
19	RT Asset Energy Amt	555 19	\$ 796,518.65	\$ (1,625,221.44)	\$ 455,815.15	\$ (372,887.64)			18,370	(35,898)
20	RT FBT Congestion Amt	555 20	\$ -	\$ -	\$ -	\$ -				
21	RT FBT Loss Amt	555 21	\$ -	\$ -	\$ -	\$ -				
22	RT Congestion Rebate on COGA	555 22	\$ -	\$ -	\$ -	\$ -				
23	RT Loss Rebate on COGA	555 23	\$ -	\$ -	\$ -	\$ -				
24	RT Distribution of Losses Amt	555 24	\$ -	\$ (314,349.38)	\$ 5,087.83	\$ (309,261.55)				
25	RT Misc Amt	555 25	\$ -	\$ -	\$ 5.96	\$ 5.96				
26	RT Non-Asset Energy Amt	555 26	\$ 1,943,109.55	\$ (1,952,811.33)	\$ -	\$ (9,701.78)			43,705	(43,536)
27	RT Net Inadvertent Amt	555 27	\$ 6,670.83	\$ (1,687.01)	\$ (808.41)	\$ 4,175.41				
28	RT Revenue Neutrality Uplift Amt	555 28	\$ 23,699.48	\$ (5,384.37)	\$ -	\$ 13,364.59				
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 29	\$ 159,876.84	\$ -	\$ (24,623.95)	\$ 135,252.89				
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 30	\$ -	\$ -	\$ -	\$ -				
31	RT Uninstructed Deviation Amt	555 31	\$ 1,178.30	\$ -	\$ -	\$ 1,178.30				
32	RT Virtual Energy Amt	555 32	\$ 169,047.50	\$ -	\$ -	\$ 169,047.50			6,142	
33	TOTAL FOR BOOK		\$ 26,633,673.06	\$ (21,959,213.26)	\$ 446,861.45	\$ 5,121,321.25	\$ (800,859.36)	\$ 4,320,461.89	555,898	(478,484)
34	Net MISO Charges for Retail = (B) 35+ (C) 35 + (D)35		\$ 5,121,321.25							
35	Net KWH for retail = ((G) 33 + (H) 33) * 1,000		\$ 77,414,409						77,414,409	
36	Cost per KWH		\$ 0.06615							
	* covers time period of 12-28-06 to 01-26-07 * increased for losses of 2.8%									
					Net MISO KWH (adjusted cumulatively)		per kWh	Net Intersystem	Total	
	MISO Book Totals		\$ 4,674,459.80		77,414,409					
	January Adjustments		\$ 446,861.45		9,399,186					
	Total MISO		\$ 5,121,321.25		86,813,595					

Public Document - Trade Secret Data Has Been Excised

Otter Tail Power Company Detail of MISO Day 2 Charges for North Dakota FCA February 2007* includes any adjustments									
Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H) Charge types with MWH for Retail
1	DA Mkt Admin Amt	555 01	\$ 61 384 52	\$ -	\$ -	\$ 61 384 52	-	-	0
2	DA Asset Energy Amt	555 02	\$ 38 999 909 38	\$ (29 374 260 44)	\$ -	\$ 9 625 648 94	-	-	(428 860)
3	DA FBT Congestion Amt	555 03	\$ 112 854 70	\$ (1 281 12)	\$ -	\$ 111 573 58	-	-	-
4	DA FBT Loss Amt	555 04	\$ 404 718 52	\$ -	\$ -	\$ 404 718 52	-	-	-
5	DA Congestion Rebate on COGA	555 05	\$ -	\$ -	\$ -	\$ -	-	-	-
6	DA Losses Rebate on COGA	555 06	\$ -	\$ -	\$ -	\$ -	-	-	-
7	DA Congestion Rebate on Optron B GFA	555 07	\$ -	\$ (109 798 24)	\$ -	\$ (109 798 24)	-	-	-
8	DA Losses Rebate on Optron B GFA	555 08	\$ -	\$ (199 080 20)	\$ -	\$ (199 080 20)	-	-	-
9	DA Non-asset Energy Amt	555 09	\$ 1 215 428 10	\$ (2 024 426 56)	\$ -	\$ (808 998 46)	-	-	(23 499)
10	DA Revenue Sufficiency Guarantee Distribution Amt	555 10	\$ 43,286 68	\$ -	\$ (879 61)	\$ 42 407 07	-	-	-
11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 11	\$ -	\$ (12 200 77)	\$ -	\$ (12 200 77)	-	-	-
12	DA Virtual Energy Amt	555 12	\$ -	\$ -	\$ -	\$ -	-	-	-
13	FTR Mkt Admin Amt	555 13	\$ 1 825 15	\$ -	\$ -	\$ 1 825 15	-	-	-
14	FTR Hourly Allocation Amt	555 14	\$ 76 984 82	\$ (550 441 86)	\$ (2 96)	\$ (473 460 00)	-	-	-
15	FTR Monthly Allocation Amt	555 15	\$ -	\$ (21 179 20)	\$ 8 60	\$ (21 170 60)	-	-	-
16	FTR Transaction Amt	555 16	\$ -	\$ -	\$ -	\$ -	-	-	-
17	FTR Yearly Allocation Amt	555 17	\$ -	\$ -	\$ -	\$ -	-	-	-
18	RT Mkt Admin Amt	555 18	\$ 4 761 59	\$ -	\$ (299 50)	\$ 4 462 09	-	-	-
19	RT Asset Energy Amt	555 19	\$ 920 725 96	\$ (3 985 305 72)	\$ 426 432 52	\$ (2 638 147 24)	-	-	(50 847)
20	RT FBT Congestion Amt	555 20	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT FBT Loss Amt	555 21	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Congestion Rebate on COGA	555 22	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Loss Rebate on COGA	555 23	\$ -	\$ -	\$ -	\$ -	-	-	-
24	RT Distribution of Losses Amt	555 24	\$ -	\$ (642,775 77)	\$ (13 430 48)	\$ (656 206 25)	-	-	-
25	RT Misc Amt	555 25	\$ -	\$ -	\$ -	\$ -	-	-	-
26	RT Non-Asset Energy Amt	555 26	\$ 791 016 39	\$ (718 006 82)	\$ -	\$ 73 009 57	-	-	(10 460)
27	RT Net Inadvertent Amt	555 27	\$ 17 444 38	\$ (2 188 78)	\$ (2 168 07)	\$ 13 087 53	-	-	-
28	RT Revenue Neutrality Uplift Amt	555 28	\$ 204,293 56	\$ (2,340 87)	\$ 4 889 55	\$ 206 842 24	-	-	-
29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555 29	\$ 284 322 99	\$ -	\$ 34 866 06	\$ 319 189 05	-	-	-
30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555 30	\$ -	\$ -	\$ -	\$ -	-	-	-
31	RT Uninstructed Deviation Amt	555 31	\$ 648 93	\$ -	\$ (31 67)	\$ 617 26	-	-	-
32	RT Virtual Energy Amt	555 32	\$ -	\$ -	\$ -	\$ -	-	-	-
33	TOTAL FOR BOOK		\$ 43 139 605 67	\$ (37 643 286 35)	\$ 449,384 44	\$ 5,945,703 76	\$ (1 289 744 11)	\$ 4 655 959 65	573 382 (513 666)
34	Net MISO Charges for Retail = (B) 35+ (C) 35 + (D)35		\$ 5,945,703 76						
35	Net KWH for retail = ((G) 33 + (H) 33) * 1 000		\$ 59 716 015						59,716,015
36	Cost per KWH		\$ 0 09957						
	* covers time period of 01 27-07 to 02-26-07 increased for losses of 2 8%								
					Net MISO KWH (adjusted cumulatively)		per kWh	Net Intersystem	Total
	MISO Book Totals		\$ 5 496 319 32		59,716,015				
	February Adjustments		\$ 449 384 44		10 066 833				
	Total MISO		\$ 5,945,703 76		69,782,848				

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE FEBRUARY 2, 2004

EFFECTIVE 2/02/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2003 <u>September</u>	2003 <u>October</u>	2003 <u>November</u>	2003 <u>December</u>	Total <u>This Period</u>
Purchased Power	\$ 12,264,010	\$ 9,475,598	\$ 13,008,952	\$ 14,795,974	\$ 49,544,535
Steam Plant Generation	\$ 4,211,726	\$ 4,841,238	\$ 4,438,554	\$ 3,289,924	\$ 16,781,442
Other Plant Generation	\$ 39,986	\$ 157,352	\$ 132,217	\$ 342,367	\$ 671,922
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,944	\$ 25,074	\$ 25,910	\$ 102,002
Less Intersystem Sales	\$ (12,549,669)	\$ (9,607,304)	\$ (10,839,558)	\$ (9,959,992)	\$ (42,956,522)
NET ENERGY COSTS	\$ 3,991,127	\$ 4,892,829	\$ 6,765,239	\$ 8,494,183	\$ 24,143,379

Prior (over) under recovery \$ 1,880,278

Adjusted Net Energy Costs \$ 26,023,657

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	323,379,430	328,150,554	329,232,295	256,773,005	1,237,535,284
Other Plant IC Generation	1,781,582	2,325,847	2,458,237	4,420,229	10,985,895
Hydro Plant Generation	541,660	255,933	219,481	275,216	1,292,290
Purchased Power	215,190,182	174,613,996	289,725,506	292,829,389	972,359,073
Total Energy	540,892,854	505,346,330	621,635,519	554,297,839	2,222,172,542
Less Intersystem Sales	(263,351,000)	(223,069,000)	(207,324,000)	(153,189,000)	(846,933,000)
Net Energy - KWHs	277,541,854	282,277,330	414,311,519	401,108,839	1,375,239,542

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,210,210,797

Delivered Cost per kWh \$ 0 021503

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0050**

TRUE UP FOR DECEMBER

1) Net Energy (kWhs) Less 12% Losses	352,975,778
2) Net Energy Costs for the System -- Most recent month	\$ 8,494,183
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,814,570
4) Net to be Recovered from COE (2 - 3)	\$ 2,679,613
5) COE Recovery Rate Effective for December	\$ (0 0012)
6) Amount Recovered by COE (5 X 1)	\$ (423,571)
7) Over / (Under) Recovery (4 - 6)	\$ (3,103,184)
8) Cumulative Over / (Under) Recovery	\$ (1,880,278)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE MARCH 2, 2004

EFFECTIVE 3/02/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2003 <u>October</u>	2003 <u>November</u>	2003 <u>December</u>	2004 <u>January</u>	Total <u>This Period</u>
Purchased Power	\$ 9,475,598	\$ 13,008,952	\$ 14,795,974	\$ 19,595,386	\$ 56,875,911
Steam Plant Generation	\$ 4,841,238	\$ 4,438,554	\$ 3,289,924	\$ 4,674,788	\$ 17,244,504
Other Plant Generation	\$ 157,352	\$ 132,217	\$ 342,367	\$ 497,858	\$ 1,129,794
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,944	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,838
Less Intersystem Sales	\$ (9,607,304)	\$ (10,839,558)	\$ (9,959,992)	\$ (16,090,432)	\$ (46,497,285)
NET ENERGY COSTS	\$ 4,892,829	\$ 6,765,239	\$ 8,494,183	\$ 8,703,510	\$ 28,855,762

Prior (over) under recovery	0 01475310	0 01348153	0 01281258	0 01334961	\$ 4,117,291
Adjusted Net Energy Costs					\$ 32,973,053

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	328,150,554	329,232,295	256,773,005	350,181,517	1,264,337,371
Other Plant IC Generation	2,325,847	2,458,237	4,420,229	7,793,822	16,998,135
Hydro Plant Generation	255,933	219,481	275,216	305,074	1,055,704
Purchased Power	174,613,996	289,725,506	292,829,389	263,879,643	1,021,048,534
Total Energy	505,346,330	621,635,519	554,297,839	622,160,056	2,303,439,744
Less Intersystem Sales	(223,069,000)	(207,324,000)	(153,189,000)	(186,654,000)	(770,236,000)
Net Energy - KWHs	282,277,330	414,311,519	401,108,839	435,506,056	1,533,203,744

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,349,219,295

Delivered Cost per kWh \$ 0 024439
 Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0080**

TRUE UP FOR JANUARY

1) Net Energy (kWhs) Less 12% Losses	383,245,329
2) Net Energy Costs for the System -- Most recent month	\$ 8,703,510
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,313,200
4) Net to be Recovered from COE (2 - 3)	\$ 2,390,310
5) COE Recovery Rate Effective for January	\$ 0 0004
6) Amount Recovered by COE (5 X 1)	\$ 153,298
7) Over / (Under) Recovery (4 - 6)	\$ (2,237,012)
8) Cumulative Over / (Under) Recovery	\$ (4,117,291)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE APRIL 2, 2004

EFFECTIVE 4/02/04
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2003 <u>November</u>	2003 <u>December</u>	2004 <u>January</u>	2004 <u>February</u>	Total <u>This Period</u>
Purchased Power	\$ 13,008,952	\$ 14,795,974	\$ 19,595,386	\$ 19,905,796	\$ 67,306,109
Steam Plant Generation	\$ 4,438,554	\$ 3,289,924	\$ 4,674,788	\$ 4,434,377	\$ 16,837,643
Other Plant Generation	\$ 132,217	\$ 342,367	\$ 497,858	\$ 249,104	\$ 1,221,546
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 24,239	\$ 101,133
Less Intersystem Sales	\$ (10,839,558)	\$ (9,959,992)	\$ (16,090,432)	\$ (17,311,541)	\$ (54,201,523)
NET ENERGY COSTS	\$ 6,765,239	\$ 8,494,183	\$ 8,703,510	\$ 7,301,975	\$ 31,264,908

Prior (over) under recovery \$ 4,433,516

Adjusted Net Energy Costs \$ 35,698,424

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	329,232,295	256,773,005	350,181,517	327,088,176	1,263,274,993
Other Plant IC Generation	2,458,237	4,420,229	7,793,822	4,019,146	18,691,434
Hydro Plant Generation	219,481	275,216	305,074	560,155	1,359,926
Purchased Power	289,725,506	292,829,389	263,879,643	250,421,437	1,096,855,975
Total Energy	621,635,519	554,297,839	622,160,056	582,088,914	2,380,182,328
Less Intersystem Sales	(207,324,000)	(153,189,000)	(186,654,000)	(212,399,000)	(759,566,000)
Net Energy - KWHs	414,311,519	401,108,839	435,506,056	369,689,914	1,620,616,328

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,426,142,369

Delivered Cost per kWh \$ 0 025031

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0086**

TRUE UP FOR FEBRUARY

1) Net Energy (kWhs) Less 12% Losses	325,327,124
2) Net Energy Costs for the System -- Most recent month	\$ 7,301,975
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,359,114
4) Net to be Recovered from COE (2 - 3)	\$ 1,942,861
5) COE Recovery Rate Effective for February	\$ 0 0050
6) Amount Recovered by COE (5 X 1)	\$ 1,626,636
7) Over / (Under) Recovery (4 - 6)	\$ (316,225)
8) Cumulative Over / (Under) Recovery	\$ (4,433,516)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE MAY 3, 2004

EFFECTIVE 5/03/04
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2003 December	2004 January	2004 February	2004 March	Total This Period
Purchased Power	\$ 14,795,974	\$ 19,595,386	\$ 19,905,796	\$ 17,214,601	\$ 71,511,758
Steam Plant Generation	\$ 3,289,924	\$ 4,674,788	\$ 4,434,377	\$ 4,764,833	\$ 17,163,922
Other Plant Generation	\$ 342,367	\$ 497,858	\$ 249,104	\$ 32,604	\$ 1,121,933
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 24,239	\$ 25,910	\$ 101,969
Less Intersystem Sales	\$ (9,959,992)	\$ (16,090,432)	\$ (17,311,541)	\$ (16,737,373)	\$ (60,099,338)
NET ENERGY COSTS	\$ 8,494,183	\$ 8,703,510	\$ 7,301,975	\$ 5,300,575	\$ 29,800,244

Prior (over) under recovery \$ 1,967,716

Adjusted Net Energy Costs \$ 31,767,960

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	256,773,005	350,181,517	327,088,176	357,254,510	1,291,297,208
Other Plant IC Generation	4,420,229	7,793,822	4,019,146	787,766	17,020,963
Hydro Plant Generation	275,216	305,074	560,155	1,247,610	2,388,055
Purchased Power	292,829,389	263,879,643	250,421,437	210,481,972	1,017,612,441
Total Energy	554,297,839	622,160,056	582,088,914	569,771,858	2,328,318,667
Less Intersystem Sales	(153,189,000)	(186,654,000)	(212,399,000)	(209,153,000)	(761,395,000)
Net Energy - KWHs	401,108,839	435,506,056	369,689,914	360,618,858	1,566,923,667

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,378,892,827

Delivered Cost per kWh \$ 0 023039

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0066**

TRUE UP FOR MARCH

1) Net Energy (kWhs) Less 12% Losses	317,344,595
2) Net Energy Costs for the System -- Most recent month	\$ 5,300,575
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,227,618
4) Net to be Recovered from COE (2 - 3)	\$ 72,957
5) COE Recovery Rate Effective for March	\$ 0 0080
6) Amount Recovered by COE (5 X 1)	\$ 2,538,757
7) Over / (Under) Recovery (4 - 6)	\$ 2,465,800
8) Cumulative Over / (Under) Recovery	\$ (1,967,716)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JUNE 2, 2004

EFFECTIVE 6/02/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 January	2004 February	2004 March	2004 April	Total This Period
Purchased Power	\$ 19,595,386	\$ 19,905,796	\$ 17,214,601	\$ 15,225,006	\$ 71,940,789
Steam Plant Generation	\$ 4,674,788	\$ 4,434,377	\$ 4,764,833	\$ 3,579,227	\$ 17,453,225
Other Plant Generation	\$ 497,858	\$ 249,104	\$ 32,604	\$ 45,663	\$ 825,229
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 24,239	\$ 25,910	\$ 25,040	\$ 101,099
Less Intersystem Sales	\$ (16,090,432)	\$ (17,311,541)	\$ (16,737,373)	\$ (13,456,885)	\$ (63,596,231)
NET ENERGY COSTS	\$ 8,703,510	\$ 7,301,975	\$ 5,300,575	\$ 5,418,051	\$ 26,724,111

Prior (over) under recovery \$ 610,855

Adjusted Net Energy Costs \$ 27,334,967

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	350,181,517	327,088,176	357,254,510	274,224,184	1,308,748,387
Other Plant IC Generation	7,793,822	4,019,146	787,766	674,254	13,274,988
Hydro Plant Generation	305,074	560,155	1,247,610	2,143,230	4,256,069
Purchased Power	263,879,643	250,421,437	210,481,972	200,295,241	925,078,293
Total Energy	622,160,056	582,088,914	569,771,858	477,336,909	2,251,357,737
Less Intersystem Sales	(186,654,000)	(212,399,000)	(209,153,000)	(170,283,000)	(778,489,000)
Net Energy - KWHs	435,506,056	369,689,914	360,618,858	307,053,909	1,472,868,737

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,296,124,489

Delivered Cost per kWh \$ 0 021090

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0046

TRUE UP FOR APRIL

1) Net Energy (kWhs) Less 12% Losses	270,207,440
2) Net Energy Costs for the System -- Most recent month	\$ 5,418,051
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,451,127
4) Net to be Recovered from COE (2 - 3)	\$ 966,924
5) COE Recovery Rate Effective for April	\$ 0 0086
6) Amount Recovered by COE (5 X 1)	\$ 2,323,784
7) Over / (Under) Recovery (4 - 6)	\$ 1,356,860
8) Cumulative Over / (Under) Recovery	\$ (610,855)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE JULY 1, 2004

EFFECTIVE 7/01/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>February</u>	2004 <u>March</u>	2004 <u>April</u>	2004 <u>May</u>	Total <u>This Period</u>
Purchased Power	\$ 19,905,796	\$ 17,214,601	\$ 15,225,006	\$ 8,087,736	\$ 60,433,139
Steam Plant Generation	\$ 4,434,377	\$ 4,764,833	\$ 3,579,227	\$ 3,797,993	\$ 16,576,430
Other Plant Generation	\$ 249,104	\$ 32,604	\$ 45,663	\$ 33,376	\$ 360,747
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 24,239	\$ 25,910	\$ 25,040	\$ 25,910	\$ 101,099
Less Intersystem Sales	\$ (17,311,541)	\$ (16,737,373)	\$ (13,456,885)	\$ (6,163,232)	\$ (53,669,031)
NET ENERGY COSTS	\$ 7,301,975	\$ 5,300,575	\$ 5,418,051	\$ 5,781,784	\$ 23,802,384

Prior (over) under recovery \$ 228,802

Adjusted Net Energy Costs \$ 24,031,186

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	327,088,176	357,254,510	274,224,184	280,825,437	1,239,392,307
Other Plant IC Generation	4,019,146	787,766	674,254	296,826	5,777,992
Hydro Plant Generation	560,155	1,247,610	2,143,230	2,060,435	6,011,430
Purchased Power	250,421,437	210,481,972	200,295,241	154,207,167	815,405,817
Total Energy	582,088,914	569,771,858	477,336,909	437,389,865	2,066,587,546
Less Intersystem Sales	(212,399,000)	(209,153,000)	(170,283,000)	(133,816,000)	(725,651,000)
Net Energy - KWHs	369,689,914	360,618,858	307,053,909	303,573,865	1,340,936,546

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,180,024,160

Delivered Cost per kWh \$ 0 020365

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0039**

TRUE UP FOR MAY

- | | |
|---|--------------|
| 1) Net Energy (kWhs) Less 12% Losses | 267,145,001 |
| 2) Net Energy Costs for the System -- Most recent month | \$ 5,781,784 |
| 3) Base Cost Recovered (1 X Base Cost of Fuel) | \$ 4,400,680 |
| 4) Net to be Recovered from COE (2 - 3) | \$ 1,381,104 |
| 5) COE Recovery Rate Effective for May | \$ 0 0066 |
| 6) Amount Recovered by COE (5 X 1) | \$ 1,763,157 |
| 7) Over / (Under) Recovery (4 - 6) | \$ 382,053 |
| 8) Cumulative Over / (Under) Recovery | \$ (228,802) |

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE AUGUST 3, 2004

EFFECTIVE 8/03/04
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>March</u>	2004 <u>April</u>	2004 <u>May</u>	2004 <u>June</u>	Total <u>This Period</u>
Purchased Power	\$ 17,214,601	\$ 15,225,006	\$ 8,087,736	\$ 8,118,743	\$ 48,646,086
Steam Plant Generation	\$ 4,764,833	\$ 3,579,227	\$ 3,797,993	\$ 3,607,360	\$ 15,749,413
Other Plant Generation	\$ 32,604	\$ 45,663	\$ 33,376	\$ 129,200	\$ 240,843
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,040	\$ 25,910	\$ 25,074	\$ 101,934
Less Intersystem Sales	\$ (16,737,373)	\$ (13,456,885)	\$ (6,163,232)	\$ (6,609,143)	\$ (42,966,632)
NET ENERGY COSTS	\$ 5,300,575	\$ 5,418,051	\$ 5,781,784	\$ 5,271,234	\$ 21,771,643

Prior (over) under recovery \$ 359,537

Adjusted Net Energy Costs \$ 22,131,181

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	357,254,510	274,224,184	280,825,437	273,016,000	1,185,320,131
Other Plant IC Generation	787,766	674,254	296,826	1,620,353	3,379,199
Hydro Plant Generation	1,247,610	2,143,230	2,060,435	2,251,638	7,702,913
Purchased Power	210,481,972	200,295,241	154,207,167	148,852,934	713,837,314
Total Energy	569,771,858	477,336,909	437,389,865	425,740,925	1,910,239,557
Less Intersystem Sales	(209,153,000)	(170,283,000)	(133,816,000)	(148,539,000)	(661,791,000)
Net Energy - KWHs	360,618,858	307,053,909	303,573,865	277,201,925	1,248,448,557

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,098,634,730

Delivered Cost per kWh \$ 0 020144

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0037**

TRUE UP FOR JUNE

1) Net Energy (kWhs) Less 12% Losses	243,937,694
2) Net Energy Costs for the System -- Most recent month	\$ 5,271,234
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,018,386
4) Net to be Recovered from COE (2 - 3)	\$ 1,252,848
5) COE Recovery Rate Effective for June	\$ 0 0046
6) Amount Recovered by COE (5 X 1)	\$ 1,122,113
7) Over / (Under) Recovery (4 - 6)	\$ (130,735)
8) Cumulative Over / (Under) Recovery	\$ (359,537)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE SEPTEMBER 1, 2004

EFFECTIVE 9/01/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>April</u>	2004 <u>May</u>	2004 <u>June</u>	2004 <u>July</u>	Total <u>This Period</u>
Purchased Power	\$ 15,225,006	\$ 8,087,736	\$ 8,118,743	\$ 15,093,027	\$ 46,524,511
Steam Plant Generation	\$ 3,579,227	\$ 3,797,993	\$ 3,607,360	\$ 3,946,408	\$ 14,930,988
Other Plant Generation	\$ 45,663	\$ 33,376	\$ 129,200	\$ 377,548	\$ 585,787
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,040	\$ 25,910	\$ 25,074	\$ 25,910	\$ 101,934
Less Intersystem Sales	\$ (13,456,885)	\$ (6,163,232)	\$ (6,609,143)	\$ (13,078,592)	\$ (39,307,851)
NET ENERGY COSTS	\$ 5,418,051	\$ 5,781,784	\$ 5,271,234	\$ 6,364,300	\$ 22,835,369

Prior (over) under recovery \$ 1,222,186

Adjusted Net Energy Costs \$ 24,057,554

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	274,224,184	280,825,437	273,016,000	290,158,733	1,118,224,354
Other Plant IC Generation	674,254	296,826	1,620,353	5,335,402	7,926,835
Hydro Plant Generation	2,143,230	2,060,435	2,251,638	1,800,154	8,255,457
Purchased Power	200,295,241	154,207,167	148,852,934	185,096,460	688,451,802
Total Energy	477,336,909	437,389,865	425,740,925	482,390,749	1,822,858,448
Less Intersystem Sales	(170,283,000)	(133,816,000)	(148,539,000)	(175,520,000)	(628,158,000)
Net Energy - KWHs	307,053,909	303,573,865	277,201,925	306,870,749	1,194,700,448

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,051,336,394

Delivered Cost per kWh \$ 0 022883

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0064

TRUE UP FOR JULY

1) Net Energy (kWhs) Less 12% Losses	270,046,259
2) Net Energy Costs for the System -- Most recent month	\$ 6,364,300
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,448,472
4) Net to be Recovered from COE (2 - 3)	\$ 1,915,828
5) COE Recovery Rate Effective for July	\$ 0 0039
6) Amount Recovered by COE (5 X 1)	\$ 1,053,180
7) Over / (Under) Recovery (4 - 6)	\$ (862,648)
8) Cumulative Over / (Under) Recovery	\$ (1,222,186)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE OCTOBER 1, 2004

EFFECTIVE 10/01/04
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>May</u>	2004 <u>June</u>	2004 <u>July</u>	2004 <u>August</u>	Total <u>This Period</u>
Purchased Power	\$ 8,087,736	\$ 8,118,743	\$ 15,093,027	\$ 12,760,246	\$ 44,059,752
Steam Plant Generation	\$ 3,797,993	\$ 3,607,360	\$ 3,946,408	\$ 3,817,525	\$ 15,169,286
Other Plant Generation	\$ 33,376	\$ 129,200	\$ 377,548	\$ 230,553	\$ 770,677
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,804
Less Intersystem Sales	\$ (6,163,232)	\$ (6,609,143)	\$ (13,078,592)	\$ (10,981,103)	\$ (36,832,070)
NET ENERGY COSTS	\$ 5,781,784	\$ 5,271,234	\$ 6,364,300	\$ 5,853,131	\$ 23,270,449

Prior (over) under recovery \$ 1,976,875

Adjusted Net Energy Costs \$ 25,247,324

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	280,825,437	273,016,000	290,158,733	282,711,072	1,126,711,242
Other Plant IC Generation	296,826	1,620,353	5,335,402	3,635,243	10,887,824
Hydro Plant Generation	2,060,435	2,251,638	1,800,154	1,805,615	7,917,842
Purchased Power	154,207,167	148,852,934	185,096,460	134,739,962	622,896,523
Total Energy	437,389,865	425,740,925	482,390,749	422,891,892	1,768,413,431
Less Intersystem Sales	(133,816,000)	(148,539,000)	(175,520,000)	(135,692,000)	(593,567,000)
Net Energy - KWHs	303,573,865	277,201,925	306,870,749	287,199,892	1,174,846,431

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,033,864,859

Delivered Cost per kWh \$ 0 024420

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0079**

TRUE UP FOR AUGUST

1) Net Energy (kWhs) Less 12% Losses	252,735,905
2) Net Energy Costs for the System -- Most recent month	\$ 5,853,131
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,163,319
4) Net to be Recovered from COE (2 - 3)	\$ 1,689,812
5) COE Recovery Rate Effective for August	\$ 0 0037
6) Amount Recovered by COE (5 X 1)	\$ 935,123
7) Over / (Under) Recovery (4 - 6)	\$ (754,689)
8) Cumulative Over / (Under) Recovery	\$ (1,976,875)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE NOVEMBER 1, 2004

EFFECTIVE 11/01/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>June</u>	2004 <u>July</u>	2004 <u>August</u>	2004 <u>September</u>	Total <u>This Period</u>
Purchased Power	\$ 8,118,743	\$ 15,093,027	\$ 12,760,246	\$ 6,285,894	\$ 42,257,910
Steam Plant Generation	\$ 3,607,360	\$ 3,946,408	\$ 3,817,525	\$ 3,968,322	\$ 15,339,615
Other Plant Generation	\$ 129,200	\$ 377,548	\$ 230,553	\$ 136,654	\$ 873,955
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 25,074	\$ 101,968
Less Intersystem Sales	\$ (6,609,143)	\$ (13,078,592)	\$ (10,981,103)	\$ (5,354,763)	\$ (36,023,601)
NET ENERGY COSTS	\$ 5,271,234	\$ 6,364,300	\$ 5,853,131	\$ 5,061,181	\$ 22,549,847

Prior (over) under recovery \$ 1,114,768

Adjusted Net Energy Costs \$ 23,664,614

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	273,016,000	290,158,733	282,711,072	295,809,457	1,141,695,262
Other Plant IC Generation	1,620,353	5,335,402	3,635,243	3,687,623	14,278,621
Hydro Plant Generation	2,251,638	1,800,154	1,805,615	1,681,737	7,539,144
Purchased Power	148,852,934	185,096,460	134,739,962	135,061,677	603,751,033
Total Energy	425,740,925	482,390,749	422,891,892	436,240,494	1,767,264,060
Less Intersystem Sales	(148,539,000)	(175,520,000)	(135,692,000)	(141,963,000)	(601,714,000)
Net Energy - KWHs	277,201,925	306,870,749	287,199,892	294,277,494	1,165,550,060

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,025,684,053

Delivered Cost per kWh \$ 0 023072

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0066**

TRUE UP FOR SEPTEMBER

1) Net Energy (kWhs) Less 12% Losses	258,964,195
2) Net Energy Costs for the System -- Most recent month	\$ 5,061,181
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,265,917
4) Net to be Recovered from COE (2 - 3)	\$ 795,264
5) COE Recovery Rate Effective for September	\$ 0 0064
6) Amount Recovered by COE (5 X 1)	\$ 1,657,371
7) Over / (Under) Recovery (4 - 6)	\$ 862,107
8) Cumulative Over / (Under) Recovery	\$ (1,114,768)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE DECEMBER 1, 2004

EFFECTIVE 12/01/04
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>July</u>	2004 <u>August</u>	2004 <u>September</u>	2004 <u>October</u>	Total <u>This Period</u>
Purchased Power	\$ 15,093,027	\$ 12,760,246	\$ 6,285,894	\$ 8,306,993	\$ 42,446,160
Steam Plant Generation	\$ 3,946,408	\$ 3,817,525	\$ 3,968,322	\$ 3,510,788	\$ 15,243,043
Other Plant Generation	\$ 377,548	\$ 230,553	\$ 136,654	\$ 79,768	\$ 824,523
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 25,074	\$ 25,944	\$ 102,838
Less Intersystem Sales	\$ (13,078,592)	\$ (10,981,103)	\$ (5,354,763)	\$ (6,328,063)	\$ (35,742,521)
NET ENERGY COSTS	\$ 6,364,300	\$ 5,853,131	\$ 5,061,181	\$ 5,595,430	\$ 22,874,043

Prior (over) under recovery \$ (220,932)

Adjusted Net Energy Costs \$ 22,653,110

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	290,158,733	282,711,072	295,809,457	290,909,384	1,159,588,646
Other Plant IC Generation	5,335,402	3,635,243	3,687,623	709,401	13,367,669
Hydro Plant Generation	1,800,154	1,805,615	1,681,737	2,011,870	7,299,376
Purchased Power	185,096,460	134,739,962	135,061,677	149,724,479	604,622,578
Total Energy	482,390,749	422,891,892	436,240,494	443,355,134	1,784,878,269
Less Intersystem Sales	(175,520,000)	(135,692,000)	(141,963,000)	(120,199,000)	(573,374,000)
Net Energy - KWHs	306,870,749	287,199,892	294,277,494	323,156,134	1,211,504,269

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,066,123,757

Delivered Cost per kWh \$ 0 021248

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0048**

TRUE UP FOR OCTOBER

1) Net Energy (kWhs) Less 12% Losses	284,377,398
2) Net Energy Costs for the System -- Most recent month	\$ 5,595,430
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,684,549
4) Net to be Recovered from COE (2 - 3)	\$ 910,881
5) COE Recovery Rate Effective for October	\$ 0 0079
6) Amount Recovered by COE (5 X 1)	\$ 2,246,581
7) Over / (Under) Recovery (4 - 6)	\$ 1,335,700
8) Cumulative Over / (Under) Recovery	\$ 220,932

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JANUARY 3, 2005

EFFECTIVE 1/03/05
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 August	2004 September	2004 October	2004 November	Total This Period
Purchased Power	\$ 12,760,246	\$ 6,285,894	\$ 8,306,993	\$ 9,754,789	\$ 37,107,923
Steam Plant Generation	\$ 3,817,525	\$ 3,968,322	\$ 3,510,788	\$ 4,701,391	\$ 15,998,026
Other Plant Generation	\$ 230,553	\$ 136,654	\$ 79,768	\$ 79,416	\$ 526,391
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,944	\$ 25,074	\$ 102,002
Less Intersystem Sales	\$ (10,981,103)	\$ (5,354,763)	\$ (6,328,063)	\$ (8,633,267)	\$ (31,297,195)
NET ENERGY COSTS	\$ 5,853,131	\$ 5,061,181	\$ 5,595,430	\$ 5,927,404	\$ 22,437,146

Prior (over) under recovery \$ (1,420,619)

Adjusted Net Energy Costs \$ 21,016,527

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	282,711,072	295,809,457	290,909,384	335,228,983	1,204,658,896
Other Plant IC Generation	3,635,243	3,687,623	709,401	641,105	8,673,372
Hydro Plant Generation	1,805,615	1,681,737	2,011,870	2,530,462	8,029,684
Purchased Power	134,739,962	135,061,677	149,724,479	161,861,340	581,387,458
Total Energy	422,891,892	436,240,494	443,355,134	500,261,890	1,802,749,410
Less Intersystem Sales	(135,692,000)	(141,963,000)	(120,199,000)	(149,247,000)	(547,101,000)
Net Energy - KWHs	287,199,892	294,277,494	323,156,134	351,014,890	1,255,648,410

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,104,970,601

Delivered Cost per kWh \$ 0 019020

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0025

TRUE UP FOR NOVEMBER

- | | |
|---|--------------|
| 1) Net Energy (kWhs) Less 12% Losses | 308,893,103 |
| 2) Net Energy Costs for the System -- Most recent month | \$ 5,927,404 |
| 3) Base Cost Recovered (1 X Base Cost of Fuel) | \$ 5,088,396 |
| 4) Net to be Recovered from COE (2 - 3) | \$ 839,008 |
| 5) COE Recovery Rate Effective for November | \$ 0 0066 |
| 6) Amount Recovered by COE (5 X 1) | \$ 2,038,694 |
| 7) Over / (Under) Recovery (4 - 6) | \$ 1,199,686 |
| 8) Cumulative Over / (Under) Recovery | \$ 1,420,619 |

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE FEBRUARY 1, 2005

EFFECTIVE 2/01/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>September</u>	2004 <u>October</u>	2004 <u>November</u>	2004 <u>December</u>	Total <u>This Period</u>
Purchased Power	\$ 6,285,894	\$ 8,306,993	\$ 9,754,789	\$ 16,966,944	\$ 41,314,620
Steam Plant Generation	\$ 3,968,322	\$ 3,510,788	\$ 4,701,391	\$ 5,212,112	\$ 17,392,613
Other Plant Generation	\$ 136,654	\$ 79,768	\$ 79,416	\$ 372,786	\$ 668,624
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,944	\$ 25,074	\$ 25,910	\$ 102,002
Less Intersystem Sales	\$ (5,354,763)	\$ (6,328,063)	\$ (8,633,267)	\$ (14,604,718)	\$ (34,920,810)
NET ENERGY COSTS	\$ 5,061,181	\$ 5,595,430	\$ 5,927,404	\$ 7,973,034	\$ 24,557,048

Prior (over) under recovery \$ (1,431,412)

Adjusted Net Energy Costs \$ 23,125,637

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	295,809,457	290,909,384	335,228,983	362,090,803	1,284,038,627
Other Plant IC Generation	3,687,623	709,401	641,105	4,726,491	9,764,620
Hydro Plant Generation	1,681,737	2,011,870	2,530,462	2,291,532	8,515,601
Purchased Power	135,061,677	149,724,479	161,861,340	245,002,165	691,649,661
Total Energy	436,240,494	443,355,134	500,261,890	614,110,991	1,993,968,509
Less Intersystem Sales	(141,963,000)	(120,199,000)	(149,247,000)	(187,630,000)	(599,039,000)
Net Energy - KWHs	294,277,494	323,156,134	351,014,890	426,480,991	1,394,929,509

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,227,537,968

Delivered Cost per kWh \$ 0 018839

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0024**

TRUE UP FOR DECEMBER

1) Net Energy (kWhs) Less 12% Losses	375,303,272
2) Net Energy Costs for the System -- Most recent month	\$ 7,973,034
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,182,371
4) Net to be Recovered from COE (2 - 3)	\$ 1,790,663
5) COE Recovery Rate Effective for December	\$ 0 0048
6) Amount Recovered by COE (5 X 1)	\$ 1,801,456
7) Over / (Under) Recovery (4 - 6)	\$ 10,793
8) Cumulative Over / (Under) Recovery	\$ 1,431,412

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE MARCH 2, 2005

EFFECTIVE 3/02/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>October</u>	2004 <u>November</u>	2004 <u>December</u>	2005 <u>January</u>	Total <u>This Period</u>
Purchased Power	\$ 8,306,993	\$ 9,754,789	\$ 16,966,944	\$ 12,306,284	\$ 47,335,010
Steam Plant Generation	\$ 3,510,788	\$ 4,701,391	\$ 5,212,112	\$ 5,065,391	\$ 18,489,682
Other Plant Generation	\$ 79,768	\$ 79,416	\$ 372,786	\$ 340,441	\$ 872,411
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,944	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,838
Less Intersystem Sales	\$ (6,328,063)	\$ (8,633,267)	\$ (14,604,718)	\$ (8,928,992)	\$ (38,495,039)
NET ENERGY COSTS	\$ 5,595,430	\$ 5,927,404	\$ 7,973,034	\$ 8,809,033	\$ 28,304,901

Prior (over) under recovery \$ 171,757

Adjusted Net Energy Costs \$ 28,476,658

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	290,909,384	335,228,983	362,090,803	347,689,271	1,335,918,441
Other Plant IC Generation	709,401	641,105	4,726,491	4,768,793	10,845,790
Hydro Plant Generation	2,011,870	2,530,462	2,291,532	2,130,611	8,964,475
Purchased Power	149,724,479	161,861,340	245,002,165	206,523,443	763,111,427
Total Energy	443,355,134	500,261,890	614,110,991	561,112,118	2,118,840,133
Less Intersystem Sales	(120,199,000)	(149,247,000)	(187,630,000)	(129,526,000)	(586,602,000)
Net Energy - KWHs	323,156,134	351,014,890	426,480,991	431,586,118	1,532,238,133

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,348,369,557

Delivered Cost per kWh \$ 0 021119

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0046**

TRUE UP FOR JANUARY

1) Net Energy (kWhs) Less 12% Losses	379,795,784
2) Net Energy Costs for the System -- Most recent month	\$ 8,809,033
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,256,376
4) Net to be Recovered from COE (2 - 3)	\$ 2,552,657
5) COE Recovery Rate Effective for January	\$ 0 0025
6) Amount Recovered by COE (5 X 1)	\$ 949,489
7) Over / (Under) Recovery (4 - 6)	\$ (1,603,168)
8) Cumulative Over / (Under) Recovery	\$ (171,757)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE APRIL 1, 2005

EFFECTIVE 4/01/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 November	2004 December	2005 January	2005 February	Total This Period
Purchased Power	\$ 9,754,789	\$ 16,966,944	\$ 12,306,284	\$ 9,746,223	\$ 48,774,240
Steam Plant Generation	\$ 4,701,391	\$ 5,212,112	\$ 5,065,391	\$ 4,495,567	\$ 19,474,461
Other Plant Generation	\$ 79,416	\$ 372,786	\$ 340,441	\$ 89,114	\$ 881,757
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 23,403	\$ 100,297
Less Intersystem Sales	\$ (8,633,267)	\$ (14,604,718)	\$ (8,928,992)	\$ (7,926,531)	\$ (40,093,508)
NET ENERGY COSTS	\$ 5,927,404	\$ 7,973,034	\$ 8,809,033	\$ 6,427,775	\$ 29,137,246

Prior (over) under recovery \$ 942,847

Adjusted Net Energy Costs \$ 30,080,093

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	335,228,983	362,090,803	347,689,271	322,455,567	1,367,464,624
Other Plant IC Generation	641,105	4,726,491	4,768,793	1,115,832	11,252,221
Hydro Plant Generation	2,530,462	2,291,532	2,130,611	2,082,688	9,035,293
Purchased Power	161,861,340	245,002,165	206,523,443	156,310,975	769,697,923
Total Energy	500,261,890	614,110,991	561,112,118	481,965,062	2,157,450,061
Less Intersystem Sales	(149,247,000)	(187,630,000)	(129,526,000)	(141,370,000)	(607,773,000)
Net Energy - KWHs	351,014,890	426,480,991	431,586,118	340,595,062	1,549,677,061

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,363,715,814

Delivered Cost per kWh \$ 0 022057

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0056**

TRUE UP FOR FEBRUARY

1) Net Energy (kWhs) Less 12% Losses	299,723,655
2) Net Energy Costs for the System -- Most recent month	\$ 6,427,775
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,937,348
4) Net to be Recovered from COE (2 - 3)	\$ 1,490,427
5) COE Recovery Rate Effective for February	\$ 0 0024
6) Amount Recovered by COE (5 X 1)	\$ 719,337
7) Over / (Under) Recovery (4 - 6)	\$ (771,090)
8) Cumulative Over / (Under) Recovery	\$ (942,847)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE MAY 2, 2005

EFFECTIVE 5/02/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2004 <u>December</u>	2005 <u>January</u>	2005 <u>February</u>	2005 <u>March</u>	Total <u>This Period</u>
Purchased Power	\$ 16,966,944	\$ 12,306,284	\$ 9,746,223	\$ 9,094,262	\$ 48,113,712
Steam Plant Generation	\$ 5,212,112	\$ 5,065,391	\$ 4,495,567	\$ 5,114,695	\$ 19,887,765
Other Plant Generation	\$ 372,786	\$ 340,441	\$ 89,114	\$ 71,327	\$ 873,668
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 23,403	\$ 25,910	\$ 101,133
Less Intersystem Sales	\$ (14,604,718)	\$ (8,928,992)	\$ (7,926,531)	\$ (7,729,476)	\$ (39,189,718)
NET ENERGY COSTS	\$ 7,973,034	\$ 8,809,033	\$ 6,427,775	\$ 6,576,718	\$ 29,786,560

Prior (over) under recovery \$ 776,229

Adjusted Net Energy Costs \$ 30,562,789

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	362,090,803	347,689,271	322,455,567	344,420,199	1,376,655,840
Other Plant IC Generation	4,726,491	4,768,793	1,115,832	836,557	11,447,673
Hydro Plant Generation	2,291,532	2,130,611	2,082,688	2,310,686	8,815,517
Purchased Power	245,002,165	206,523,443	156,310,975	154,187,603	762,024,186
Total Energy	614,110,991	561,112,118	481,965,062	501,755,045	2,158,943,216
Less Intersystem Sales	(187,630,000)	(129,526,000)	(141,370,000)	(138,120,000)	(596,646,000)
Net Energy - KWHs	426,480,991	431,586,118	340,595,062	363,635,045	1,562,297,216

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,374,821,550

Delivered Cost per kWh \$ 0 022230

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0058**

TRUE UP FOR MARCH

1) Net Energy (kWhs) Less 12% Losses	319,998,840
2) Net Energy Costs for the System -- Most recent month	\$ 6,576,718
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,271,341
4) Net to be Recovered from COE (2 - 3)	\$ 1,305,377
5) COE Recovery Rate Effective for March	\$ 0 0046
6) Amount Recovered by COE (5 X 1)	\$ 1,471,995
7) Over / (Under) Recovery (4 - 6)	\$ 166,618
8) Cumulative Over / (Under) Recovery	\$ (776,229)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JUNE 2, 2005

EFFECTIVE 6/02/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>January</u>	2005 <u>February</u>	2005 <u>March</u>	2005 <u>April</u>	Total <u>This Period</u>
Purchased Power	\$ 12,306,284	\$ 9,746,223	\$ 9,094,262	\$ 5,979,059	\$ 37,125,828
Steam Plant Generation	\$ 5,065,391	\$ 4,495,567	\$ 5,114,695	\$ 3,032,025	\$ 17,707,678
Other Plant Generation	\$ 340,441	\$ 89,114	\$ 71,327	\$ 348,247	\$ 849,129
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 23,403	\$ 25,910	\$ 25,040	\$ 100,263
Less Intersystem Sales	\$ (8,928,992)	\$ (7,926,531)	\$ (7,729,476)	\$ (2,815,620)	\$ (27,400,620)
Net Retail MISO Day 2				\$ 283,591	\$ 283,591
NET ENERGY COSTS	\$ 8,809,033	\$ 6,427,775	\$ 6,576,718	\$ 6,852,343	\$ 28,665,869

Prior (over) under recovery \$ 879,303

Adjusted Net Energy Costs \$ 29,545,172

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	347,689,271	322,455,567	344,420,199	212,750,118	1,227,315,155
Other Plant IC Generation	4,768,793	1,115,832	836,557	1,466,530	8,187,712
Hydro Plant Generation	2,130,611	2,082,688	2,310,686	2,162,607	8,686,592
Purchased Power	206,523,443	156,310,975	154,187,603	157,359,215	674,381,236
Total Energy	561,112,118	481,965,062	501,755,045	373,738,470	1,918,570,695
Less Intersystem Sales	(129,526,000)	(141,370,000)	(138,120,000)	(95,113,000)	(504,129,000)
Net Retail MISO Day 2				68,840,842	68,840,842
Net Energy - KWHs	431,586,118	340,595,062	363,635,045	347,466,312	1,483,282,537

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,305,288,633

Delivered Cost per kWh \$ 0 022635

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0062**

TRUE UP FOR APRIL

1) Net Energy (kWhs) Less 12% Losses	305,770,355
2) Net Energy Costs for the System -- Most recent month	\$ 6,852,343
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,036,955
4) Net to be Recovered from COE (2 - 3)	\$ 1,815,388
5) COE Recovery Rate Effective for April	\$ 0 0056
6) Amount Recovered by COE (5 X 1)	\$ 1,712,314
7) Over / (Under) Recovery (4 - 6)	\$ (103,074)
8) Cumulative Over / (Under) Recovery	\$ (879,303)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JULY 1, 2005

EFFECTIVE 7/01/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>February</u>	2005 <u>March</u>	2005 <u>April</u>	2005 <u>May</u>	Total <u>This Period</u>
Purchased Power	\$ 9,746,223	\$ 9,094,262	\$ 5,979,059	\$ 8,155,741	\$ 32,975,285
Steam Plant Generation	\$ 4,495,567	\$ 5,114,695	\$ 3,032,025	\$ 2,387,135	\$ 15,029,422
Other Plant Generation	\$ 89,114	\$ 71,327	\$ 348,247	\$ 417,354	\$ 926,042
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 23,403	\$ 25,910	\$ 25,040	\$ 25,910	\$ 100,263
Less Intersystem Sales	\$ (7,926,531)	\$ (7,729,476)	\$ (2,815,620)	\$ (2,958,001)	\$ (21,429,629)
Net Retail MISO Day 2			\$ 283,591	\$ 310,003	\$ 593,594
NET ENERGY COSTS	\$ 6,427,775	\$ 6,576,718	\$ 6,852,343	\$ 8,338,142	\$ 28,194,978

Prior (over) under recovery \$ 2,830,165

Adjusted Net Energy Costs \$ 31,025,143

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	322,455,567	344,420,199	212,750,118	164,663,812	1,044,289,696
Other Plant IC Generation	1,115,832	836,557	1,466,530	5,109,410	8,528,329
Hydro Plant Generation	2,082,688	2,310,686	2,162,607	2,247,741	8,803,722
Purchased Power	156,310,975	154,187,603	157,359,215	208,481,429	676,339,222
Total Energy	481,965,062	501,755,045	373,738,470	380,502,392	1,737,960,969
Less Intersystem Sales	(141,370,000)	(138,120,000)	(95,113,000)	(106,829,000)	(481,432,000)
Net Retail MISO Day 2	-	-	68,840,842	52,204,199	121,045,041
Net Energy - KWHs	340,595,062	363,635,045	347,466,312	325,877,591	1,377,574,010

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,212,265,129

Delivered Cost per kWh \$ 0 025593

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0091**

TRUE UP FOR MAY

1) Net Energy (kWhs) Less 12% Losses	286,772,280
2) Net Energy Costs for the System -- Most recent month	\$ 8,338,142
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,724,000
4) Net to be Recovered from COE (2 - 3)	\$ 3,614,142
5) COE Recovery Rate Effective for May	\$ 0 0058
6) Amount Recovered by COE (5 X 1)	\$ 1,663,279
7) Over / (Under) Recovery (4 - 6)	\$ (1,950,863)
8) Cumulative Over / (Under) Recovery	\$ (2,830,165)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE AUGUST 2, 2005

EFFECTIVE 8/02/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>March</u>	2005 <u>April</u>	2005 <u>May</u>	2005 <u>June</u>	Total <u>This Period</u>
Purchased Power	\$ 9,094,262	\$ 5,979,059	\$ 8,155,741	\$ 7,658,926	\$ 30,887,989
Steam Plant Generation	\$ 5,114,695	\$ 3,032,025	\$ 2,387,135	\$ 3,980,489	\$ 14,514,344
Other Plant Generation	\$ 71,327	\$ 348,247	\$ 417,354	\$ 384,413	\$ 1,221,341
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,040	\$ 25,910	\$ 25,074	\$ 101,934
Less Intersystem Sales	\$ (7,729,476)	\$ (2,815,620)	\$ (2,958,001)	\$ (6,030,259)	\$ (19,533,357)
Net Retail MISO Day 2	\$ -	\$ 283,591	\$ 310,003	\$ 2,891,243	\$ 3,484,838
NET ENERGY COSTS	\$ 6,576,718	\$ 6,852,343	\$ 8,338,142	\$ 8,909,886	\$ 30,677,088

Prior (over) under recovery \$ 6,602,111

Adjusted Net Energy Costs \$ 37,279,199

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	344,420,199	212,750,118	164,663,812	262,783,648	984,617,777
Other Plant IC Generation	836,557	1,466,530	5,109,410	2,032,210	9,444,707
Hydro Plant Generation	2,310,686	2,162,607	2,247,741	2,020,480	8,741,514
Purchased Power	154,187,603	157,359,215	208,481,429	200,390,219	720,418,466
Total Energy	501,755,045	373,738,470	380,502,392	467,226,557	1,723,222,464
Less Intersystem Sales	(138,120,000)	(95,113,000)	(106,829,000)	(264,691,000)	(604,753,000)
Net Retail MISO Day 2	-	68,840,842	52,204,199	54,976,412	176,021,453
Net Energy - KWHs	363,635,045	347,466,312	325,877,591	257,511,969	1,294,490,917

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,139,152,007

Delivered Cost per kWh \$ 0 032725

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0163**

TRUE UP FOR JUNE

1) Net Energy (kWhs) Less 12% Losses	226,610,533
2) Net Energy Costs for the System -- Most recent month	\$ 8,909,886
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 3,732,955
4) Net to be Recovered from COE (2 - 3)	\$ 5,176,931
5) COE Recovery Rate Effective for June	\$ 0 0062
6) Amount Recovered by COE (5 X 1)	\$ 1,404,985
7) Over / (Under) Recovery (4 - 6)	\$ (3,771,946)
8) Cumulative Over / (Under) Recovery	\$ (6,602,111)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE SEPTEMBER 1, 2005

EFFECTIVE 9/01/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>April</u>	2005 <u>May</u>	2005 <u>June</u>	2005 <u>July</u>	Total <u>This Period</u>
Purchased Power	\$ 5,979,059	\$ 8,155,741	\$ 7,658,926	\$ 10,098,128	\$ 31,891,854
Steam Plant Generation	\$ 3,032,025	\$ 2,387,135	\$ 3,980,489	\$ 4,529,699	\$ 13,929,348
Other Plant Generation	\$ 348,247	\$ 417,354	\$ 384,413	\$ 472,273	\$ 1,622,287
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,040	\$ 25,910	\$ 25,074	\$ 25,910	\$ 101,934
Less Intersystem Sales	\$ (2,815,620)	\$ (2,958,001)	\$ (6,030,259)	\$ (9,145,065)	\$ (20,948,946)
Net Retail MISO Day 2	\$ 283,591	\$ 310,003	\$ 2,891,243	\$ 2,600,300	\$ 6,085,137
NET ENERGY COSTS	\$ 6,852,343	\$ 8,338,142	\$ 8,909,886	\$ 8,581,244	\$ 32,681,615

Prior (over) under recovery \$ 3,662,696

Adjusted Net Energy Costs \$ 36,344,310

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	212,750,118	164,663,812	262,783,648	310,430,068	950,627,646
Other Plant IC Generation	1,466,530	5,109,410	2,032,210	5,006,765	13,614,915
Hydro Plant Generation	2,162,607	2,247,741	2,020,480	1,546,283	7,977,111
Purchased Power	157,359,215	208,481,429	200,390,219	209,560,578	775,791,441
Total Energy	373,738,470	380,502,392	467,226,557	526,543,694	1,748,011,113
Less Intersystem Sales	(95,113,000)	(106,829,000)	(264,691,000)	(173,071,000)	(639,704,000)
Net Retail MISO Day 2	68,840,842	52,204,199	54,976,412	158,460,166	334,481,619
Net Energy - KWHs	347,466,312	325,877,591	257,511,969	511,932,860	1,442,788,732

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,269,654,084

Delivered Cost per kWh \$ 0 028625

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0122**

TRUE UP FOR JULY

1) Net Energy (kWhs) Less 12% Losses	450,500,917
2) Net Energy Costs for the System -- Most recent month	\$ 8,581,244
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 7,421,102
4) Net to be Recovered from COE (2 - 3)	\$ 1,160,142
5) COE Recovery Rate Effective for July	\$ 0 0091
6) Amount Recovered by COE (5 X 1)	\$ 4,099,558
7) Over / (Under) Recovery (4 - 6)	\$ 2,939,416
8) Cumulative Over / (Under) Recovery	\$ (3,662,696)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE OCTOBER 3, 2005

EFFECTIVE 10/03/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>May</u>	2005 <u>June</u>	2005 <u>July</u>	2005 <u>August</u>	Total <u>This Period</u>
Purchased Power	\$ 8,155,741	\$ 7,658,926	\$ 10,098,128	\$ 8,449,135	\$ 34,361,929
Steam Plant Generation	\$ 2,387,135	\$ 3,980,489	\$ 4,529,699	\$ 4,474,523	\$ 15,371,846
Other Plant Generation	\$ 417,354	\$ 384,413	\$ 472,273	\$ 686,959	\$ 1,960,999
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,804
Less Intersystem Sales	\$ (2,958,001)	\$ (6,030,259)	\$ (9,145,065)	\$ (8,084,330)	\$ (26,217,656)
Net Retail MISO Day 2	\$ 310,003	\$ 2,891,243	\$ 2,600,300	\$ 2,536,115	\$ 8,337,661
NET ENERGY COSTS	\$ 8,338,142	\$ 8,909,886	\$ 8,581,244	\$ 8,088,311	\$ 33,917,583

Prior (over) under recovery \$ 2,688,364

Adjusted Net Energy Costs \$ 36,605,947

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	164,663,812	262,783,648	310,430,068	295,169,214	1,033,046,742
Other Plant IC Generation	5,109,410	2,032,210	5,006,765	5,302,375	17,450,760
Hydro Plant Generation	2,247,741	2,020,480	1,546,283	1,706,479	7,520,983
Purchased Power	208,481,429	200,390,219	209,560,578	163,451,785	781,884,011
Total Energy	380,502,392	467,226,557	526,543,694	465,629,853	1,839,902,496
Less Intersystem Sales	(106,829,000)	(264,691,000)	(173,071,000)	(201,016,000)	(745,607,000)
Net Retail MISO Day 2	52,204,199	54,976,412	158,460,166	49,622,207	315,262,984
Net Energy - KWHs	325,877,591	257,511,969	511,932,860	314,236,060	1,409,558,480

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,240,411,462

Delivered Cost per kWh \$ 0 029511

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0130**

TRUE UP FOR AUGUST

1) Net Energy (kWhs) Less 12% Losses	276,527,733
2) Net Energy Costs for the System -- Most recent month	\$ 8,088,311
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,555,241
4) Net to be Recovered from COE (2 - 3)	\$ 3,533,070
5) COE Recovery Rate Effective for August	\$ 0 0163
6) Amount Recovered by COE (5 X 1)	\$ 4,507,402
7) Over / (Under) Recovery (4 - 6)	\$ 974,332
8) Cumulative Over / (Under) Recovery	\$ (2,688,364)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE NOVEMBER 1, 2005

EFFECTIVE 11/01/05
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>June</u>	2005 <u>July</u>	2005 <u>August</u>	2005 <u>September</u>	Total <u>This Period</u>
Purchased Power	\$ 7,658,926	\$ 10,098,128	\$ 8,449,135	\$ 9,068,845	\$ 35,275,033
Steam Plant Generation	\$ 3,980,489	\$ 4,529,699	\$ 4,474,523	\$ 4,189,469	\$ 17,174,180
Other Plant Generation	\$ 384,413	\$ 472,273	\$ 686,959	\$ 131,584	\$ 1,675,229
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 25,074	\$ 101,968
Less Intersystem Sales	\$ (6,030,259)	\$ (9,145,065)	\$ (8,084,330)	\$ (8,069,487)	\$ (31,329,142)
Net Retail MISO Day 2	\$ 2,891,243	\$ 2,600,300	\$ 2,536,115	\$ 728,446	\$ 8,756,104
NET ENERGY COSTS	\$ 8,909,886	\$ 8,581,244	\$ 8,088,311	\$ 6,073,931	\$ 31,653,372

Prior (over) under recovery \$ 1,502,041

Adjusted Net Energy Costs \$ 33,155,414

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	262,783,648	310,430,068	295,169,214	279,104,757	1,147,487,687
Other Plant IC Generation	2,032,210	5,006,765	5,302,375	651,632	12,992,982
Hydro Plant Generation	2,020,480	1,546,283	1,706,479	1,818,954	7,092,196
Purchased Power	200,390,219	209,560,578	163,451,785	156,156,464	729,559,046
Total Energy	467,226,557	526,543,694	465,629,853	437,731,807	1,897,131,911
Less Intersystem Sales	(264,691,000)	(173,071,000)	(201,016,000)	(196,985,000)	(835,763,000)
Net Retail MISO Day 2	54,976,412	158,460,166	49,622,207	46,990,343	310,049,128
Net Energy - KWHs	257,511,969	511,932,860	314,236,060	287,737,150	1,371,418,039

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,206,847,874

Delivered Cost per kWh \$ 0 027473

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0110**

TRUE UP FOR SEPTEMBER

1) Net Energy (kWhs) Less 12% Losses	253,208,692
2) Net Energy Costs for the System -- Most recent month	\$ 6,073,931
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,171,107
4) Net to be Recovered from COE (2 - 3)	\$ 1,902,824
5) COE Recovery Rate Effective for September	\$ 0 0122
6) Amount Recovered by COE (5 X 1)	\$ 3,089,146
7) Over / (Under) Recovery (4 - 6)	\$ 1,186,322
8) Cumulative Over / (Under) Recovery	\$ (1,502,041)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE DECEMBER 1, 2005

EFFECTIVE 12/01/05
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>July</u>	2005 <u>August</u>	2005 <u>September</u>	2005 <u>October</u>	Total <u>This Period</u>
Purchased Power	\$ 10,098,128	\$ 8,449,135	\$ 9,068,845	\$ 16,449,414	\$ 44,065,521
Steam Plant Generation	\$ 4,529,699	\$ 4,474,523	\$ 4,189,469	\$ 4,583,739	\$ 17,777,430
Other Plant Generation	\$ 472,273	\$ 686,959	\$ 131,584	\$ 190,111	\$ 1,480,927
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 25,074	\$ 25,944	\$ 102,838
Less Intersystem Sales	\$ (9,145,065)	\$ (8,084,330)	\$ (8,069,487)	\$ (15,440,237)	\$ (40,739,120)
Net Retail MISO Day 2	\$ 2,600,300	\$ 2,536,115	\$ 728,446	\$ 2,472,226	\$ 8,337,087
NET ENERGY COSTS	\$ 8,581,244	\$ 8,088,311	\$ 6,073,931	\$ 8,281,197	\$ 31,024,683

Prior (over) under recovery \$ 25,913

Adjusted Net Energy Costs \$ 31,050,596

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	310,430,068	295,169,214	279,104,757	300,953,299	1,185,657,338
Other Plant IC Generation	5,006,765	5,302,375	651,632	948,811	11,909,583
Hydro Plant Generation	1,546,283	1,706,479	1,818,954	1,677,613	6,749,329
Purchased Power	209,560,578	163,451,785	156,156,464	296,652,793	825,821,620
Total Energy	526,543,694	465,629,853	437,731,807	600,232,516	2,030,137,870
Less Intersystem Sales	(173,071,000)	(201,016,000)	(196,985,000)	(245,879,000)	(816,951,000)
Net Retail MISO Day 2	158,460,166	49,622,207	46,990,343	21,850,790	276,923,506
Net Energy - KWHs	511,932,860	314,236,060	287,737,150	376,204,306	1,490,110,376

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,311,297,131

Delivered Cost per kWh \$ 0 023679

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0072

TRUE UP FOR OCTOBER

1) Net Energy (kWhs) Less 12% Losses	331,059,789
2) Net Energy Costs for the System -- Most recent month	\$ 8,281,197
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,453,548
4) Net to be Recovered from COE (2 - 3)	\$ 2,827,649
5) COE Recovery Rate Effective for October	\$ 0 0130
6) Amount Recovered by COE (5 X 1)	\$ 4,303,777
7) Over / (Under) Recovery (4 - 6)	\$ 1,476,128
8) Cumulative Over / (Under) Recovery	\$ (25,913)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JANUARY 3, 2006

EFFECTIVE 1/03/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>August</u>	2005 <u>September</u>	2005 <u>October</u>	2005 <u>November</u>	Total <u>This Period</u>
Purchased Power	\$ 8,449,135	\$ 9,068,845	\$ 16,449,414	\$ 10,872,245	\$ 44,839,638
Steam Plant Generation	\$ 4,474,523	\$ 4,189,469	\$ 4,583,739	\$ 4,422,450	\$ 17,670,181
Other Plant Generation	\$ 686,959	\$ 131,584	\$ 190,111	\$ 856,545	\$ 1,865,199
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,944	\$ 25,074	\$ 102,002
Less Intersystem Sales	\$ (8,084,330)	\$ (8,069,487)	\$ (15,440,237)	\$ (10,445,785)	\$ (42,039,841)
Net Retail MISO Day 2	\$ 2,536,115	\$ 728,446	\$ 2,472,226	\$ 2,144,622	\$ 7,881,410
NET ENERGY COSTS	\$ 8,088,311	\$ 6,073,931	\$ 8,281,197	\$ 7,875,150	\$ 30,318,589

Prior (over) under recovery \$ 8,998

Adjusted Net Energy Costs \$ 30,327,587

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	295,169,214	279,104,757	300,953,299	291,364,333	1,166,591,603
Other Plant IC Generation	5,302,375	651,632	948,811	4,815,441	11,718,259
Hydro Plant Generation	1,706,479	1,818,954	1,677,613	1,924,785	7,127,831
Purchased Power	163,451,785	156,156,464	296,652,793	247,395,913	863,656,955
Total Energy	465,629,853	437,731,807	600,232,516	545,500,472	2,049,094,648
Less Intersystem Sales	(201,016,000)	(196,985,000)	(245,879,000)	(282,733,000)	(926,613,000)
Net Retail MISO Day 2	49,622,207	46,990,343	21,850,790	63,671,452	182,134,792
Net Energy - KWHs	314,236,060	287,737,150	376,204,306	326,438,924	1,304,616,440

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,148,062,467

Delivered Cost per kWh \$ 0 026416

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0099**

TRUE UP FOR NOVEMBER

1) Net Energy (kWhs) Less 12% Losses	287,266,253
2) Net Energy Costs for the System -- Most recent month	\$ 7,875,150
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,732,137
4) Net to be Recovered from COE (2 - 3)	\$ 3,143,013
5) COE Recovery Rate Effective for November	\$ 0 0110
6) Amount Recovered by COE (5 X 1)	\$ 3,159,929
7) Over / (Under) Recovery (4 - 6)	\$ 16,916
8) Cumulative Over / (Under) Recovery	\$ (8,998)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE FEBRUARY 1, 2006

EFFECTIVE 2/01/06
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 <u>September</u>	2005 <u>October</u>	2005 <u>November</u>	2005 <u>December</u>	Total <u>This Period</u>
Purchased Power	\$ 9,068,845	\$ 16,449,414	\$ 10,872,245	\$ 10,025,046	\$ 46,415,550
Steam Plant Generation	\$ 4,189,469	\$ 4,583,739	\$ 4,422,450	\$ 4,900,682	\$ 18,096,340
Other Plant Generation	\$ 131,584	\$ 190,111	\$ 856,545	\$ 762,273	\$ 1,940,513
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,944	\$ 25,074	\$ 25,910	\$ 102,002
Less Intersystem Sales	\$ (8,069,487)	\$ (15,440,237)	\$ (10,445,785)	\$ (9,993,309)	\$ (43,948,819)
Net Retail MISO Day 2	\$ 728,446	\$ 2,472,226	\$ 2,144,622	\$ 6,889,939	\$ 12,235,234
NET ENERGY COSTS	\$ 6,073,931	\$ 8,281,197	\$ 7,875,150	\$ 12,610,541	\$ 34,840,819

Prior (over) under recovery \$ 2,670,635

Adjusted Net Energy Costs \$ 37,511,455

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	279,104,757	300,953,299	291,364,333	321,954,927	1,193,377,316
Other Plant IC Generation	651,632	948,811	4,815,441	4,466,329	10,882,213
Hydro Plant Generation	1,818,954	1,677,613	1,924,785	1,816,763	7,238,115
Purchased Power	156,156,464	296,652,793	247,395,913	239,820,950	940,026,120
Total Energy	437,731,807	600,232,516	545,500,472	568,058,969	2,151,523,764
Less Intersystem Sales	(196,985,000)	(245,879,000)	(282,733,000)	(172,631,646)	(898,228,646)
Net Retail MISO Day 2	46,990,343	21,850,790	63,671,452	82,145,117	214,657,702
Net Energy - KWHs	287,737,150	376,204,306	326,438,924	477,572,440	1,467,952,820

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,291,798,482

Delivered Cost per kWh \$ 0 029038

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh 0 0125

TRUE UP FOR DECEMBER

1) Net Energy (kWhs) Less 12% Losses	420,263,747
2) Net Energy Costs for the System -- Most recent month	\$ 12,610,541
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,923,005
4) Net to be Recovered from COE (2 - 3)	\$ 5,687,536
5) COE Recovery Rate Effective for December	\$ 0 0072
6) Amount Recovered by COE (5 X 1)	\$ 3,025,899
7) Over / (Under) Recovery (4 - 6)	\$ (2,661,637)
8) Cumulative Over / (Under) Recovery	\$ (2,670,635)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE MARCH 2, 2006

EFFECTIVE 3/02/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	<u>2005</u> <u>October</u>	<u>2005</u> <u>November</u>	<u>2005</u> <u>December</u>	<u>2006</u> <u>January</u>	<u>Total</u> <u>This Period</u>
Purchased Power	\$ 16,449,414	\$ 10,872,245	\$ 10,025,046	\$ 19,754,247	\$ 57,100,953
Steam Plant Generation	\$ 4,583,739	\$ 4,422,450	\$ 4,900,682	\$ 5,035,902	\$ 18,942,773
Other Plant Generation	\$ 190,111	\$ 856,545	\$ 762,273	\$ 84,438	\$ 1,893,367
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,944	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,838
Less Intersystem Sales	\$ (15,440,237)	\$ (10,445,785)	\$ (9,993,309)	\$ (15,095,218)	\$ (50,974,550)
Net Retail MISO Day 2	\$ 2,472,226	\$ 2,144,622	\$ 6,889,939	\$ (2,037,740)	\$ 9,469,047
NET ENERGY COSTS	\$ 8,281,197	\$ 7,875,150	\$ 12,610,541	\$ 7,767,539	\$ 36,534,428

Prior (over) under recovery \$ 1,721,114

Adjusted Net Energy Costs \$ 38,255,542

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	300,953,299	291,364,333	321,954,927	328,340,507	1,242,613,066
Other Plant IC Generation	948,811	4,815,441	4,466,329	404,145	10,634,726
Hydro Plant Generation	1,677,613	1,924,785	1,816,763	1,821,901	7,241,062
Purchased Power	296,652,793	247,395,913	239,820,950	386,311,795	1,170,181,451
Total Energy	600,232,516	545,500,472	568,058,969	716,878,348	2,430,670,305
Less Intersystem Sales	(245,879,000)	(282,733,000)	(172,631,646)	(364,215,889)	(1,065,459,535)
Net Retail MISO Day 2	21,850,790	63,671,452	82,145,117	22,939,511	190,606,870
Net Energy - KWHs	376,204,306	326,438,924	477,572,440	375,601,970	1,555,817,640

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,369,119,523

Delivered Cost per kWh \$ 0 027942

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0115**

TRUE UP FOR JANUARY

1) Net Energy (kWhs) Less 12% Losses	330,529,734
2) Net Energy Costs for the System -- Most recent month	\$ 7,767,539
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,444,816
4) Net to be Recovered from COE (2 - 3)	\$ 2,322,723
5) COE Recovery Rate Effective for January	\$ 0 0099
6) Amount Recovered by COE (5 X 1)	\$ 3,272,244
7) Over / (Under) Recovery (4 - 6)	\$ 949,521
8) Cumulative Over / (Under) Recovery	\$ (1,721,114)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE APRIL 3, 2006

EFFECTIVE 4/03/06
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	<u>2005</u> <u>November</u>	<u>2005</u> <u>December</u>	<u>2006</u> <u>January</u>	<u>2006</u> <u>February</u>	<u>Total</u> <u>This Period</u>
Purchased Power	\$ 10,872,245	\$ 10,025,046	\$ 19,754,247	\$ 18,103,625	\$ 58,755,163
Steam Plant Generation	\$ 4,422,450	\$ 4,900,682	\$ 5,035,902	\$ 4,720,254	\$ 19,079,288
Other Plant Generation	\$ 856,545	\$ 762,273	\$ 84,438	\$ 152,209	\$ 1,855,465
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 23,403	\$ 100,297
Less Intersystem Sales	\$ (10,445,785)	\$ (9,993,309)	\$ (15,095,218)	\$ (14,831,135)	\$ (50,365,447)
Net Retail MISO Day 2	\$ 2,144,622	\$ 6,889,939	\$ (2,037,740)	\$ 2,521,528	\$ 9,518,349
NET ENERGY COSTS	\$ 7,875,150	\$ 12,610,541	\$ 7,767,539	\$ 10,689,883	\$ 38,943,114

Prior (over) under recovery \$ 2,682,703

Adjusted Net Energy Costs \$ 41,625,817

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	291,364,333	321,954,927	328,340,507	309,216,908	1,250,876,675
Other Plant IC Generation	4,815,441	4,466,329	404,145	917,266	10,603,181
Hydro Plant Generation	1,924,785	1,816,763	1,821,901	1,442,999	7,006,448
Purchased Power	247,395,913	239,820,950	386,311,795	311,400,416	1,184,929,074
Total Energy	545,500,472	568,058,969	716,878,348	622,977,589	2,453,415,378
Less Intersystem Sales	(282,733,000)	(172,631,646)	(364,215,889)	(293,174,737)	(1,112,755,272)
Net Retail MISO Day 2	63,671,452	82,145,117	22,939,511	51,755,183	220,511,263
Net Energy - KWHs	326,438,924	477,572,440	375,601,970	381,558,035	1,561,171,369

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,373,830,805

Delivered Cost per kWh \$ 0 030299

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0138**

TRUE UP FOR FEBRUARY

1) Net Energy (kWhs) Less 12% Losses	335,771,071
2) Net Energy Costs for the System -- Most recent month	\$ 10,689,883
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,531,157
4) Net to be Recovered from COE (2 - 3)	\$ 5,158,726
5) COE Recovery Rate Effective for February	\$ 0 0125
6) Amount Recovered by COE (5 X 1)	\$ 4,197,138
7) Over / (Under) Recovery (4 - 6)	\$ (961,588)
8) Cumulative Over / (Under) Recovery	\$ (2,682,703)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE MAY 2, 2006

EFFECTIVE 5/02/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2005 December	2006 January	2006 February	2006 March	Total This Period
Purchased Power	\$ 10,025,046	\$ 19,754,247	\$ 18,103,625	\$ 6,816,443	\$ 54,699,362
Steam Plant Generation	\$ 4,900,682	\$ 5,035,902	\$ 4,720,254	\$ 4,731,468	\$ 19,388,306
Other Plant Generation	\$ 762,273	\$ 84,438	\$ 152,209	\$ 81,441	\$ 1,080,361
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 23,403	\$ 25,910	\$ 101,133
Less Intersystem Sales	\$ (9,993,309)	\$ (15,095,218)	\$ (14,831,135)	\$ (5,490,690)	\$ (45,410,352)
Net Retail MISO Day 2	\$ 6,889,939	\$ (2,037,740)	\$ 2,521,528	\$ 2,124,900	\$ 9,498,626
NET ENERGY COSTS	\$ 12,610,541	\$ 7,767,539	\$ 10,689,883	\$ 8,289,471	\$ 39,357,435

Prior (over) under recovery \$ 2,067,748

Adjusted Net Energy Costs \$ 41,425,183

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	321,954,927	328,340,507	309,216,908	312,153,622	1,271,665,964
Other Plant IC Generation	4,466,329	404,145	917,266	611,578	6,399,318
Hydro Plant Generation	1,816,763	1,821,901	1,442,999	1,694,053	6,775,716
Purchased Power	239,820,950	386,311,795	311,400,416	202,532,677	1,140,065,838
Total Energy	568,058,969	716,878,348	622,977,589	516,991,930	2,424,906,836
Less Intersystem Sales	(172,631,646)	(364,215,889)	(293,174,737)	(203,169,398)	(1,033,191,670)
Net Retail MISO Day 2	82,145,117	22,939,511	51,755,183	47,907,185	204,746,996
Net Energy - KWHs	477,572,440	375,601,970	381,558,035	361,729,717	1,596,462,162

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,404,886,703

Delivered Cost per kWh \$ 0 029486

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0130**

TRUE UP FOR MARCH

1) Net Energy (kWhs) Less 12% Losses	318,322,151
2) Net Energy Costs for the System -- Most recent month	\$ 8,289,471
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,243,721
4) Net to be Recovered from COE (2 - 3)	\$ 3,045,750
5) COE Recovery Rate Effective for March	\$ 0 0115
6) Amount Recovered by COE (5 X 1)	\$ 3,660,705
7) Over / (Under) Recovery (4 - 6)	\$ 614,955
8) Cumulative Over / (Under) Recovery	\$ (2,067,748)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JUNE 2, 2006

EFFECTIVE 6/02/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>January</u>	2006 <u>February</u>	2006 <u>March</u>	2006 <u>April</u>	Total <u>This Period</u>
Purchased Power	\$ 19,754,247	\$ 18,103,625	\$ 6,816,443	\$ 7,764,023	\$ 52,438,338
Steam Plant Generation	\$ 5,035,902	\$ 4,720,254	\$ 4,731,468	\$ 3,057,323	\$ 17,544,947
Other Plant Generation	\$ 84,438	\$ 152,209	\$ 81,441	\$ 549,036	\$ 867,124
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 23,403	\$ 25,910	\$ 25,040	\$ 100,263
Less Intersystem Sales	\$ (15,095,218)	\$ (14,831,135)	\$ (5,490,690)	\$ (5,352,447)	\$ (40,769,490)
Net Retail MISO Day 2	\$ (2,037,740)	\$ 2,521,528	\$ 2,124,900	\$ 2,408,799	\$ 5,017,485
NET ENERGY COSTS	\$ 7,767,539	\$ 10,689,883	\$ 8,289,471	\$ 8,451,774	\$ 35,198,668

Prior (over) under recovery \$ 2,086,102

Adjusted Net Energy Costs \$ 37,284,770

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	328,340,507	309,216,908	312,153,622	186,363,847	1,136,074,884
Other Plant IC Generation	404,145	917,266	611,578	4,669,442	6,602,431
Hydro Plant Generation	1,821,901	1,442,999	1,694,053	2,288,178	7,247,131
Purchased Power	386,311,795	311,400,416	202,532,677	237,362,902	1,137,607,790
Total Energy	716,878,348	622,977,589	516,991,930	430,684,369	2,287,532,236
Less Intersystem Sales	(364,215,889)	(293,174,737)	(203,169,398)	(181,771,184)	(1,042,331,208)
Net Retail MISO Day 2	22,939,511	51,755,183	47,907,185	67,653,787	190,255,666
Net Energy - KWHs	375,601,970	381,558,035	361,729,717	316,566,972	1,435,456,694

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,263,201,891

Delivered Cost per kWh \$ 0 029516

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0130**

TRUE UP FOR APRIL

1) Net Energy (kWhs) Less 12% Losses	278,578,935
2) Net Energy Costs for the System -- Most recent month	\$ 8,451,774
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,589,031
4) Net to be Recovered from COE (2 - 3)	\$ 3,862,743
5) COE Recovery Rate Effective for April	\$ 0 0138
6) Amount Recovered by COE (5 X 1)	\$ 3,844,389
7) Over / (Under) Recovery (4 - 6)	\$ (18,354)
8) Cumulative Over / (Under) Recovery	\$ (2,086,102)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JULY 3, 2006

EFFECTIVE 7/03/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>February</u>	2006 <u>March</u>	2006 <u>April</u>	2006 <u>May</u>	Total <u>This Period</u>
Purchased Power	\$ 18,103,625	\$ 6,816,443	\$ 7,764,023	\$ 7,997,968	\$ 40,682,059
Steam Plant Generation	\$ 4,720,254	\$ 4,731,468	\$ 3,057,323	\$ 3,939,474	\$ 16,448,519
Other Plant Generation	\$ 152,209	\$ 81,441	\$ 549,036	\$ 107,340	\$ 890,026
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 23,403	\$ 25,910	\$ 25,040	\$ 25,910	\$ 100,263
Less Intersystem Sales	\$ (14,831,135)	\$ (5,490,690)	\$ (5,352,447)	\$ (4,011,397)	\$ (29,685,668)
Net Retail MISO Day 2	\$ 2,521,528	\$ 2,124,900	\$ 2,408,799	\$ 1,667,406	\$ 8,722,632
NET ENERGY COSTS	\$ 10,689,883	\$ 8,289,471	\$ 8,451,774	\$ 9,726,701	\$ 37,157,830

Prior (over) under recovery \$ 3,354,738

Adjusted Net Energy Costs \$ 40,512,568

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	309,216,908	312,153,622	186,363,847	231,354,486	1,039,088,863
Other Plant IC Generation	917,266	611,578	4,669,442	1,394,422	7,592,708
Hydro Plant Generation	1,442,999	1,694,053	2,288,178	2,060,571	7,485,801
Purchased Power	311,400,416	202,532,677	237,362,902	317,053,488	1,068,349,483
Total Energy	622,977,589	516,991,930	430,684,369	551,862,967	2,122,516,855
Less Intersystem Sales	(293,174,737)	(203,169,398)	(181,771,184)	(253,976,985)	(932,092,304)
Net Retail MISO Day 2	51,755,183	47,907,185	67,653,787	28,223,935	195,540,090
Net Energy - KWHs	381,558,035	361,729,717	316,566,972	326,109,917	1,385,964,641

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,219,648,884

Delivered Cost per kWh \$ 0 033217

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0167**

TRUE UP FOR MAY

1) Net Energy (kWhs) Less 12% Losses	286,976,727
2) Net Energy Costs for the System -- Most recent month	\$ 9,726,701
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,727,368
4) Net to be Recovered from COE (2 - 3)	\$ 4,999,333
5) COE Recovery Rate Effective for May	\$ 0 0130
6) Amount Recovered by COE (5 X 1)	\$ 3,730,697
7) Over / (Under) Recovery (4 - 6)	\$ (1,268,636)
8) Cumulative Over / (Under) Recovery	\$ (3,354,738)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE AUGUST 2, 2006

EFFECTIVE 8/02/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>March</u>	2006 <u>April</u>	2006 <u>May</u>	2006 <u>June</u>	Total <u>This Period</u>
Purchased Power	\$ 6,816,443	\$ 7,764,023	\$ 7,997,968	\$ 10,408,330	\$ 32,986,764
Steam Plant Generation	\$ 4,731,468	\$ 3,057,323	\$ 3,939,474	\$ 3,605,490	\$ 15,333,755
Other Plant Generation	\$ 81,441	\$ 549,036	\$ 107,340	\$ 198,042	\$ 935,859
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,040	\$ 25,910	\$ 25,074	\$ 101,934
Less Intersystem Sales	\$ (5,490,690)	\$ (5,352,447)	\$ (4,011,397)	\$ (7,848,927)	\$ (22,703,461)
Net Retail MISO Day 2	\$ 2,124,900	\$ 2,408,799	\$ 1,667,406	\$ 702,174	\$ 6,903,278
NET ENERGY COSTS	\$ 8,289,471	\$ 8,451,774	\$ 9,726,701	\$ 7,090,182	\$ 33,558,129

Prior (over) under recovery \$ 3,690,404

Adjusted Net Energy Costs \$ 37,248,533

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	312,153,622	186,363,847	231,354,486	235,955,284	965,827,239
Other Plant IC Generation	611,578	4,669,442	1,394,422	1,161,400	7,836,842
Hydro Plant Generation	1,694,053	2,288,178	2,060,571	1,752,731	7,795,533
Purchased Power	<u>202,532,677</u>	<u>237,362,902</u>	<u>317,053,488</u>	<u>290,876,192</u>	<u>1,047,825,259</u>
Total Energy	516,991,930	430,684,369	551,862,967	529,745,607	2,029,284,873
Less Intersystem Sales	(203,169,398)	(181,771,184)	(253,976,985)	(281,580,388)	(920,497,955)
Net Retail MISO Day 2	<u>47,907,185</u>	<u>67,653,787</u>	<u>28,223,935</u>	<u>12,262,492</u>	<u>156,047,399</u>
Net Energy - KWHs	<u>361,729,717</u>	<u>316,566,972</u>	<u>326,109,917</u>	<u>260,427,711</u>	<u>1,264,834,317</u>

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,113,054,199

Delivered Cost per kWh \$ 0 033465

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0169**

TRUE UP FOR JUNE

1) Net Energy (kWhs) Less 12% Losses	229,176,386
2) Net Energy Costs for the System -- Most recent month	\$ 7,090,182
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 3,775,223
4) Net to be Recovered from COE (2 - 3)	\$ 3,314,959
5) COE Recovery Rate Effective for June	\$ 0 0130
6) Amount Recovered by COE (5 X 1)	\$ 2,979,293
7) Over / (Under) Recovery (4 - 6)	\$ (335,666)
8) Cumulative Over / (Under) Recovery	\$ (3,690,404)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE SEPTEMBER 1, 2006

EFFECTIVE 9/01/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>April</u>	2006 <u>May</u>	2006 <u>June</u>	2006 <u>July</u>	Total <u>This Period</u>
Purchased Power	\$ 7,764,023	\$ 7,997,968	\$ 10,408,330	\$ 6,371,793	\$ 32,542,114
Steam Plant Generation	\$ 3,057,323	\$ 3,939,474	\$ 3,605,490	\$ 5,048,284	\$ 15,650,571
Other Plant Generation	\$ 549,036	\$ 107,340	\$ 198,042	\$ 778,404	\$ 1,632,822
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,040	\$ 25,910	\$ 25,074	\$ 25,910	\$ 101,934
Less Intersystem Sales	\$ (5,352,447)	\$ (4,011,397)	\$ (7,848,927)	\$ (5,582,486)	\$ (22,795,257)
Net Retail MISO Day 2	\$ 2,408,799	\$ 1,667,406	\$ 702,174	\$ (1,244,855)	\$ 3,533,524
NET ENERGY COSTS	\$ 8,451,774	\$ 9,726,701	\$ 7,090,182	\$ 5,397,050	\$ 30,665,707

Prior (over) under recovery \$ 118,799

Adjusted Net Energy Costs \$ 30,784,506

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	186,363,847	231,354,486	235,955,284	337,094,841	990,768,458
Other Plant IC Generation	4,669,442	1,394,422	1,161,400	7,192,841	14,418,105
Hydro Plant Generation	2,288,178	2,060,571	1,752,731	1,725,557	7,827,037
Purchased Power	237,362,902	317,053,488	290,876,192	222,319,477	1,067,612,059
Total Energy	430,684,369	551,862,967	529,745,607	568,332,716	2,080,625,659
Less Intersystem Sales	(181,771,184)	(253,976,985)	(281,580,388)	(227,131,932)	(944,460,489)
Net Retail MISO Day 2	67,653,787	28,223,935	12,262,492	(33,973,410)	74,166,804
Net Energy - KWHs	316,566,972	326,109,917	260,427,711	307,227,374	1,210,331,974

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,065,092,137

Delivered Cost per kWh \$ 0 028903

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0124

TRUE UP FOR JULY

1) Net Energy (kWhs) Less 12% Losses	270,360,089
2) Net Energy Costs for the System -- Most recent month	\$ 5,397,050
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,453,642
4) Net to be Recovered from COE (2 - 3)	\$ 943,408
5) COE Recovery Rate Effective for July	\$ 0 0167
6) Amount Recovered by COE (5 X 1)	\$ 4,515,013
7) Over / (Under) Recovery (4 - 6)	\$ 3,571,605
8) Cumulative Over / (Under) Recovery	\$ (118,799)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE OCTOBER 2, 2006

EFFECTIVE 10/02/06
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>May</u>	2006 <u>June</u>	2006 <u>July</u>	2006 <u>August</u>	Total <u>This Period</u>
Purchased Power	\$ 7,997,968	\$ 10,408,330	\$ 6,371,793	\$ 5,940,898	\$ 30,718,988
Steam Plant Generation	\$ 3,939,474	\$ 3,605,490	\$ 5,048,284	\$ 5,129,477	\$ 17,722,725
Other Plant Generation	\$ 107,340	\$ 198,042	\$ 778,404	\$ 581,099	\$ 1,664,885
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,804
Less Intersystem Sales	\$ (4,011,397)	\$ (7,848,927)	\$ (5,582,486)	\$ (5,042,515)	\$ (22,485,325)
Net Retail MISO Day 2	\$ 1,667,406	\$ 702,174	\$ (1,244,855)	\$ 285,672	\$ 1,410,397
NET ENERGY COSTS	\$ 9,726,701	\$ 7,090,182	\$ 5,397,050	\$ 6,920,541	\$ 29,134,474

Prior (over) under recovery \$ (2,678,081)

Adjusted Net Energy Costs \$ 26,456,394

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	231,354,486	235,955,284	337,094,841	337,701,891	1,142,106,502
Other Plant IC Generation	1,394,422	1,161,400	7,192,841	3,850,935	13,599,598
Hydro Plant Generation	2,060,571	1,752,731	1,725,557	922,934	6,461,793
Purchased Power	317,053,488	290,876,192	222,319,477	295,678,366	1,125,927,523
Total Energy	551,862,967	529,745,607	568,332,716	638,154,126	2,288,095,416
Less Intersystem Sales	(253,976,985)	(281,580,388)	(227,131,932)	(298,826,865)	(1,061,516,170)
Net Retail MISO Day 2	28,223,935	12,262,492	(33,973,410)	(8,445,300)	(1,932,283)
Net Energy - KWHs	326,109,917	260,427,711	307,227,374	330,881,961	1,224,646,963

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,077,689,327

Delivered Cost per kWh \$ 0 024549

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0081**

TRUE UP FOR AUGUST

1) Net Energy (kWhs) Less 12% Losses	291,176,126
2) Net Energy Costs for the System -- Most recent month	\$ 6,920,541
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,796,544
4) Net to be Recovered from COE (2 - 3)	\$ 2,123,997
5) COE Recovery Rate Effective for August	\$ 0 0169
6) Amount Recovered by COE (5 X 1)	\$ 4,920,877
7) Over / (Under) Recovery (4 - 6)	\$ 2,796,880
8) Cumulative Over / (Under) Recovery	\$ 2,678,081

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE NOVEMBER 1, 2006

EFFECTIVE 11/01/06
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>June</u>	2006 <u>July</u>	2006 <u>August</u>	2006 <u>September</u>	Total <u>This Period</u>
Purchased Power	\$ 10,408,330	\$ 6,371,793	\$ 5,940,898	\$ 4,832,358	\$ 27,553,378
Steam Plant Generation	\$ 3,605,490	\$ 5,048,284	\$ 5,129,477	\$ 4,253,773	\$ 18,037,024
Other Plant Generation	\$ 198,042	\$ 778,404	\$ 581,099	\$ 54,569	\$ 1,612,114
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 25,074	\$ 101,968
Less Intersystem Sales	\$ (7,848,927)	\$ (5,582,486)	\$ (5,042,515)	\$ (3,910,899)	\$ (22,384,827)
Net Retail MISO Day 2	\$ 702,174	\$ (1,244,855)	\$ 285,672	\$ 2,901,506	\$ 2,644,498
NET ENERGY COSTS	\$ 7,090,182	\$ 5,397,050	\$ 6,920,541	\$ 8,156,382	\$ 27,564,155

Prior (over) under recovery \$ (2,040,973)

Adjusted Net Energy Costs \$ 25,523,182

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	235,955,284	337,094,841	337,701,891	274,974,827	1,185,726,843
Other Plant IC Generation	1,161,400	7,192,841	3,850,935	406,954	12,612,130
Hydro Plant Generation	1,752,731	1,725,557	922,934	977,994	5,379,216
Purchased Power	290,876,192	222,319,477	295,678,366	234,564,187	1,043,438,222
Total Energy	529,745,607	568,332,716	638,154,126	510,923,962	2,247,156,411
Less Intersystem Sales	(281,580,388)	(227,131,932)	(298,826,865)	(254,784,076)	(1,062,323,261)
Net Retail MISO Day 2	12,262,492	(33,973,410)	(8,445,300)	39,798,529	9,642,311
Net Energy - KWHs	260,427,711	307,227,374	330,881,961	295,938,415	1,194,475,461

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,051,138,406

Delivered Cost per kWh \$ 0 024281

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0078

TRUE UP FOR SEPTEMBER

1) Net Energy (kWhs) Less 12% Losses	260,425,805
2) Net Energy Costs for the System -- Most recent month	\$ 8,156,382
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,289,994
4) Net to be Recovered from COE (2 - 3)	\$ 3,866,388
5) COE Recovery Rate Effective for September	\$ 0 0124
6) Amount Recovered by COE (5 X 1)	\$ 3,229,280
7) Over / (Under) Recovery (4 - 6)	\$ (637,108)
8) Cumulative Over / (Under) Recovery	\$ 2,040,973

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE DECEMBER 1, 2006

EFFECTIVE 12/01/06
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>July</u>	2006 <u>August</u>	2006 <u>September</u>	2006 <u>October</u>	Total <u>This Period</u>
Purchased Power	\$ 6,371,793	\$ 5,940,898	\$ 4,832,358	\$ 3,072,300	\$ 20,217,348
Steam Plant Generation	\$ 5,048,284	\$ 5,129,477	\$ 4,253,773	\$ 5,021,762	\$ 19,453,296
Other Plant Generation	\$ 778,404	\$ 581,099	\$ 54,569	\$ 537,238	\$ 1,951,310
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,910	\$ 25,074	\$ 25,944	\$ 102,838
Less Intersystem Sales	\$ (5,582,486)	\$ (5,042,515)	\$ (3,910,899)	\$ (2,048,016)	\$ (16,583,916)
Net Retail MISO Day 2	\$ (1,244,855)	\$ 285,672	\$ 2,901,506	\$ 1,990,632	\$ 3,932,956
NET ENERGY COSTS	\$ 5,397,050	\$ 6,920,541	\$ 8,156,382	\$ 8,599,859	\$ 29,073,833

Prior (over) under recovery \$ (1,240,605)

Adjusted Net Energy Costs \$ 27,833,227

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	337,094,841	337,701,891	274,974,827	330,368,510	1,280,140,069
Other Plant IC Generation	7,192,841	3,850,935	406,954	4,008,160	15,458,890
Hydro Plant Generation	1,725,557	922,934	977,994	1,022,593	4,649,078
Purchased Power	222,319,477	295,678,366	234,564,187	331,653,059	1,084,215,089
Total Energy	568,332,716	638,154,126	510,923,962	667,052,322	2,384,463,126
Less Intersystem Sales	(227,131,932)	(298,826,865)	(254,784,076)	(340,048,851)	(1,120,791,724)
Net Retail MISO Day 2	(33,973,410)	(8,445,300)	39,798,529	33,679,371	31,059,190
Net Energy - KWHs	307,227,374	330,881,961	295,938,415	360,682,842	1,294,730,592

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,139,362,921

Delivered Cost per kWh \$ 0 024429

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh

\$ 0 0079

TRUE UP FOR OCTOBER

1) Net Energy (kWhs) Less 12% Losses	317,400,901
2) Net Energy Costs for the System -- Most recent month	\$ 8,599,859
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,228,545
4) Net to be Recovered from COE (2 - 3)	\$ 3,371,314
5) COE Recovery Rate Effective for October	\$ 0 0081
6) Amount Recovered by COE (5 X 1)	\$ 2,570,947
7) Over / (Under) Recovery (4 - 6)	\$ (800,367)
8) Cumulative Over / (Under) Recovery	\$ 1,240,605

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE JANUARY 3, 2007

EFFECTIVE 1/03/07
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>August</u>	2006 <u>September</u>	2006 <u>October</u>	2006 <u>November</u>	Total <u>This Period</u>
Purchased Power	\$ 5,940,898	\$ 4,832,358	\$ 3,072,300	\$ 4,321,503	\$ 18,167,058
Steam Plant Generation	\$ 5,129,477	\$ 4,253,773	\$ 5,021,762	\$ 4,839,515	\$ 19,244,527
Other Plant Generation	\$ 581,099	\$ 54,569	\$ 537,238	\$ 513,552	\$ 1,686,458
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,910	\$ 25,074	\$ 25,944	\$ 25,074	\$ 102,002
Less Intersystem Sales	\$ (5,042,515)	\$ (3,910,899)	\$ (2,048,016)	\$ (3,292,702)	\$ (14,294,131)
Net Retail MISO Day 2	\$ 285,672	\$ 2,901,506	\$ 1,990,632	\$ 2,352,891	\$ 7,530,701
NET ENERGY COSTS	\$ 6,920,541	\$ 8,156,382	\$ 8,599,859	\$ 8,759,832	\$ 32,436,615

Prior (over) under recovery \$ 333,858

Adjusted Net Energy Costs \$ 32,770,473

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	337,701,891	274,974,827	330,368,510	306,021,148	1,249,066,376
Other Plant IC Generation	3,850,935	406,954	4,008,160	3,325,230	11,591,279
Hydro Plant Generation	922,934	977,994	1,022,593	1,270,889	4,194,410
Purchased Power	295,678,366	234,564,187	331,653,059	171,614,322	1,033,509,934
Total Energy	638,154,126	510,923,962	667,052,322	482,231,589	2,298,361,999
Less Intersystem Sales	(298,826,865)	(254,784,076)	(340,048,851)	(172,610,687)	(1,066,270,479)
Net Retail MISO Day 2	(8,445,300)	39,798,529	33,679,371	26,769,020	91,801,620
Net Energy - KWHs	330,881,961	295,938,415	360,682,842	336,389,922	1,323,893,140

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,165,025,963

Delivered Cost per kWh \$ 0 028129

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0116**

TRUE UP FOR NOVEMBER

1) Net Energy (kWhs) Less 12% Losses	296,023,131
2) Net Energy Costs for the System -- Most recent month	\$ 8,759,832
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 4,876,389
4) Net to be Recovered from COE (2 - 3)	\$ 3,883,443
5) COE Recovery Rate Effective for November	\$ 0 0078
6) Amount Recovered by COE (5 X 1)	\$ 2,308,980
7) Over / (Under) Recovery (4 - 6)	\$ (1,574,463)
8) Cumulative Over / (Under) Recovery	\$ (333,858)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE FEBRUARY 1, 2007

EFFECTIVE 2/01/07
CYCLE '1'
RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 September	2006 October	2006 November	2006 December	Total This Period
Purchased Power	\$ 4,832,358	\$ 3,072,300	\$ 4,321,503	\$ 11,133,700	\$ 23,359,860
Steam Plant Generation	\$ 4,253,773	\$ 5,021,762	\$ 4,839,515	\$ 5,104,562	\$ 19,219,612
Other Plant Generation	\$ 54,569	\$ 537,238	\$ 513,552	\$ 604,331	\$ 1,709,690
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,944	\$ 25,074	\$ 25,910	\$ 102,002
Less Intersystem Sales	\$ (3,910,899)	\$ (2,048,016)	\$ (3,292,702)	\$ (9,966,594)	\$ (19,218,210)
Net Retail MISO Day 2	\$ 2,901,506	\$ 1,990,632	\$ 2,352,891	\$ 4,081,966	\$ 11,326,995
NET ENERGY COSTS	\$ 8,156,382	\$ 8,599,859	\$ 8,759,832	\$ 10,983,875	\$ 36,499,949

Prior (over) under recovery \$ 1,835,970

Adjusted Net Energy Costs \$ 38,335,918

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	274,974,827	330,368,510	306,021,148	331,654,373	1,243,018,858
Other Plant IC Generation	406,954	4,008,160	3,325,230	3,903,513	11,643,857
Hydro Plant Generation	977,994	1,022,593	1,270,889	1,382,987	4,654,463
Purchased Power	234,564,187	331,653,059	171,614,322	533,180,999	1,271,012,567
Total Energy	510,923,962	667,052,322	482,231,589	870,121,872	2,530,329,745
Less Intersystem Sales	(254,784,076)	(340,048,851)	(172,610,687)	(479,628,604)	(1,247,072,218)
Net Retail MISO Day 2	39,798,529	33,679,371	26,769,020	51,583,215	151,830,135
Net Energy - KWHs	295,938,415	360,682,842	336,389,922	442,076,483	1,435,087,662

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,262,877,143

Delivered Cost per kWh \$ 0 030356

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh **\$ 0 0138**

TRUE UP FOR DECEMBER

1) Net Energy (kWhs) Less 12% Losses	389,027,305
2) Net Energy Costs for the System -- Most recent month	\$ 10,983,875
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,408,447
4) Net to be Recovered from COE (2 - 3)	\$ 4,575,428
5) COE Recovery Rate Effective for December	\$ 0 0079
6) Amount Recovered by COE (5 X 1)	\$ 3,073,316
7) Over / (Under) Recovery (4 - 6)	\$ (1,502,112)
8) Cumulative Over / (Under) Recovery	\$ (1,835,970)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE MARCH 2, 2007

EFFECTIVE 3/02/07
 CYCLE '1'
 RATE LEVEL 44

<u>ENERGY COSTS</u>	2006 <u>October</u>	2006 <u>November</u>	2006 <u>December</u>	2007 <u>January</u>	Total <u>This Period</u>
Purchased Power	\$ 3,072,300	\$ 4,321,503	\$ 11,133,700	\$ 6,279,924	\$ 24,807,426
Steam Plant Generation	\$ 5,021,762	\$ 4,839,515	\$ 5,104,562	\$ 4,892,298	\$ 19,858,137
Other Plant Generation	\$ 537,238	\$ 513,552	\$ 604,331	\$ 571,452	\$ 2,226,573
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,944	\$ 25,074	\$ 25,910	\$ 25,910	\$ 102,838
Less Intersystem Sales	\$ (2,048,016)	\$ (3,292,702)	\$ (9,966,594)	\$ (4,551,380)	\$ (19,858,691)
Net Retail MISO Day 2	\$ 1,990,632	\$ 2,352,891	\$ 4,081,966	\$ 5,121,321	\$ 13,546,810
NET ENERGY COSTS	\$ 8,599,859	\$ 8,759,832	\$ 10,983,875	\$ 12,339,525	\$ 40,683,092

Prior (over) under recovery \$ 2,450,763

Adjusted Net Energy Costs \$ 43,133,855

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	330,368,510	306,021,148	331,654,373	312,851,659	1,280,895,690
Other Plant IC Generation	4,008,160	3,325,230	3,903,513	5,091,444	16,328,347
Hydro Plant Generation	1,022,593	1,270,889	1,382,987	1,836,323	5,512,792
Purchased Power	331,653,059	171,614,322	533,180,999	229,767,298	1,266,215,678
Total Energy	667,052,322	482,231,589	870,121,872	549,546,724	2,568,952,507
Less Intersystem Sales	(340,048,851)	(172,610,687)	(479,628,604)	(161,756,277)	(1,154,044,419)
Net Retail MISO Day 2	33,679,371	26,769,020	51,583,215	86,813,595	198,845,201
Net Energy - KWHs	360,682,842	336,389,922	442,076,483	474,604,042	1,613,753,289

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,420,102,894

Delivered Cost per kWh \$ 0 030374

Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0139

TRUE UP FOR JANUARY

1) Net Energy (kWhs) Less 12% Losses	417,651,557
2) Net Energy Costs for the System -- Most recent month	\$ 12,339,525
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 6,879,974
4) Net to be Recovered from COE (2 - 3)	\$ 5,459,551
5) COE Recovery Rate Effective for January	\$ 0 0116
6) Amount Recovered by COE (5 X 1)	\$ 4,844,758
7) Over / (Under) Recovery (4 - 6)	\$ (614,793)
8) Cumulative Over / (Under) Recovery	\$ (2,450,763)

Exhibit PB-1 is the same as Attachment 32-A&B to Interrogatory No 32 of North Dakota OTP Large Industrial Energy Group

NORTH DAKOTA
 OTTER TAIL POWER COMPANY
 COST OF ENERGY ADJUSTMENT
 FOR BILLING TO BE EFFECTIVE APRIL 2, 2007

EFFECTIVE 4/02/07
 CYCLE '1'
 RATE LEVEL 44

ENERGY COSTS	2006 November	2006 December	2007 January	2007 February	Total This Period
Purchased Power	\$ 4,321,503	\$ 11,133,700	\$ 6,279,924	\$ 1,557,502	\$ 23,292,629
Steam Plant Generation	\$ 4,839,515	\$ 5,104,562	\$ 4,892,298	\$ 4,641,534	\$ 19,477,909
Other Plant Generation	\$ 513,552	\$ 604,331	\$ 571,452	\$ 1,582,193	\$ 3,271,528
Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -	\$ -
Coyote Coal Conv Tax	\$ 25,074	\$ 25,910	\$ 25,910	\$ 23,403	\$ 100,297
Less Intersystem Sales	\$ (3,292,702)	\$ (9,966,594)	\$ (4,551,380)	\$ (1,812,551)	\$ (19,623,227)
Net Retail MISO Day 2	\$ 2,352,891	\$ 4,081,966	\$ 5,121,321	\$ 5,945,704	\$ 17,501,882
NET ENERGY COSTS	\$ 8,759,832	\$ 10,983,875	\$ 12,339,525	\$ 11,937,784	\$ 44,021,017

Prior (over) under recovery \$ 4,929,577

Adjusted Net Energy Costs \$ 48,950,594

ASSOCIATED ENERGY -- KWH

Net Generation - Steam	306,021,148	331,654,373	312,851,659	290,500,880	1,241,028,060
Other Plant IC Generation	3,325,230	3,903,513	5,091,444	11,617,091	23,937,278
Hydro Plant Generation	1,270,889	1,382,987	1,836,323	1,722,661	6,212,860
Purchased Power	171,614,322	533,180,999	229,767,298	84,945,768	1,019,508,387
Total Energy	482,231,589	870,121,872	549,546,724	388,786,400	2,290,686,585
Less Intersystem Sales	(172,610,687)	(479,628,604)	(161,756,277)	(103,506,006)	(917,501,574)
Net Retail MISO Day 2	26,769,020	51,583,215	86,813,595	69,782,848	234,948,678
Net Energy - KWHs	336,389,922	442,076,483	474,604,042	355,063,242	1,608,133,689
	92%	76%	67%	86%	

Energy Adjusted to Retail Sales (Net Energy X (1 00 - 12)) 1,415,157,646

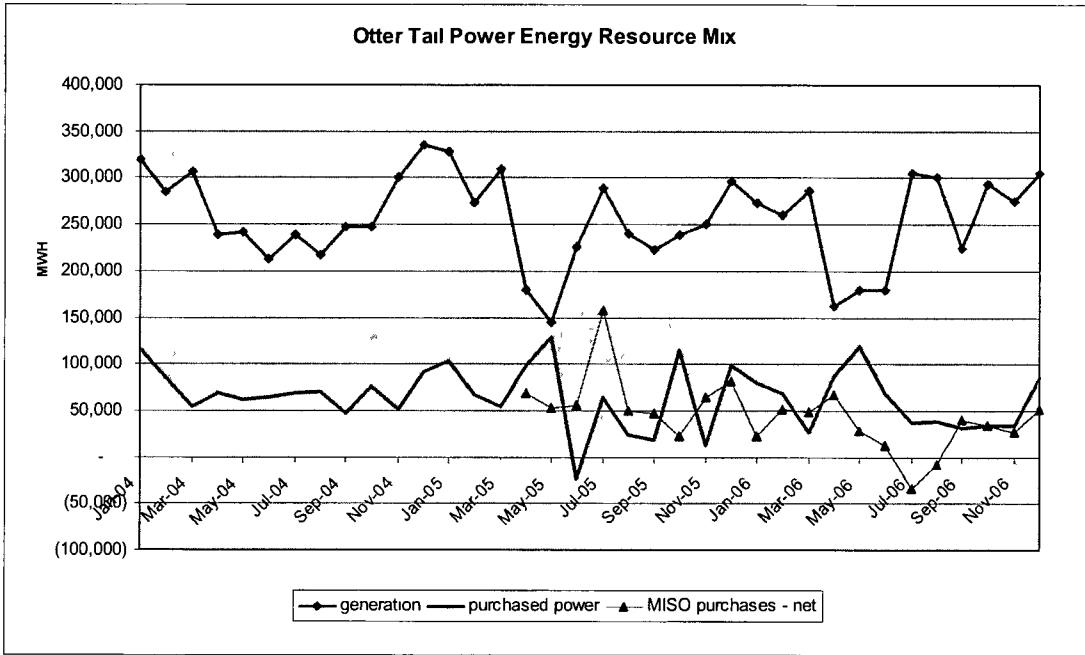
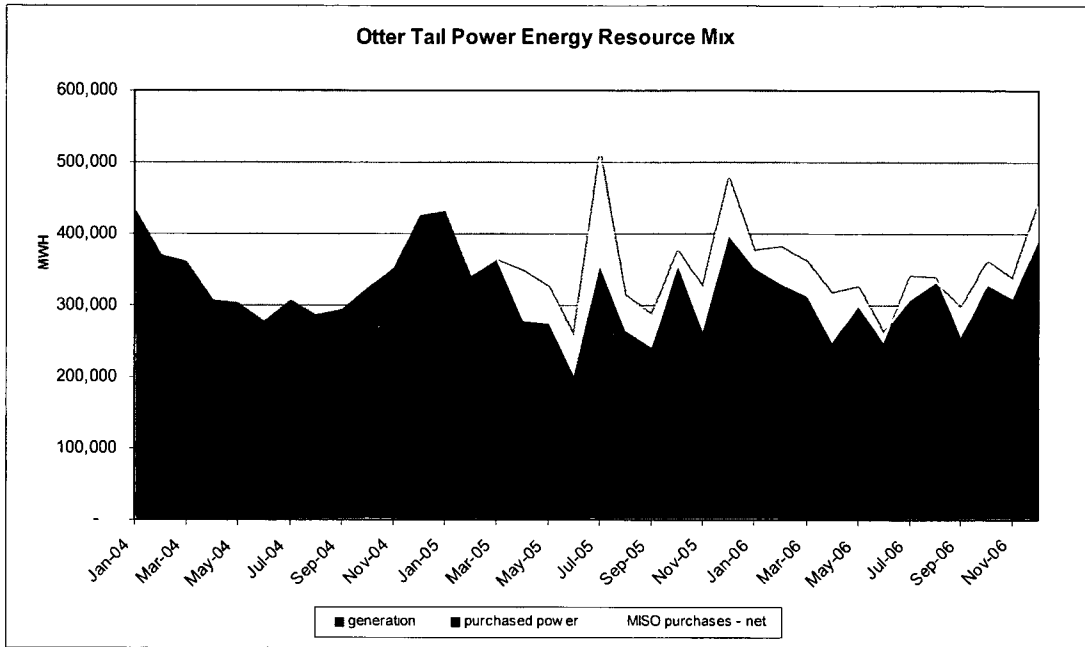
Delivered Cost per kWh \$ 0 034590

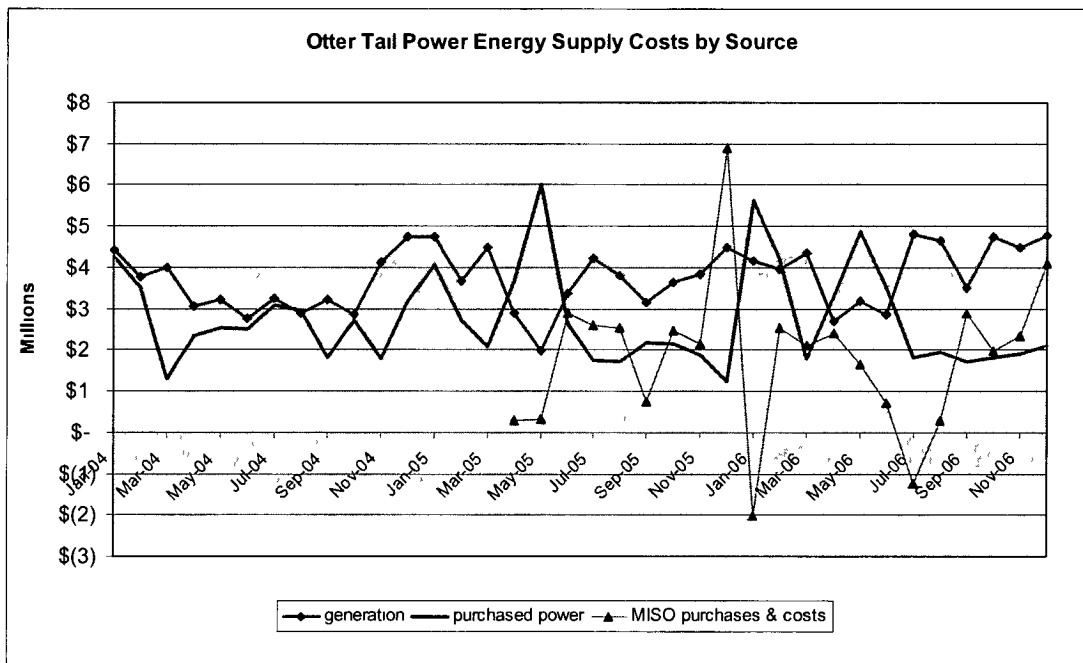
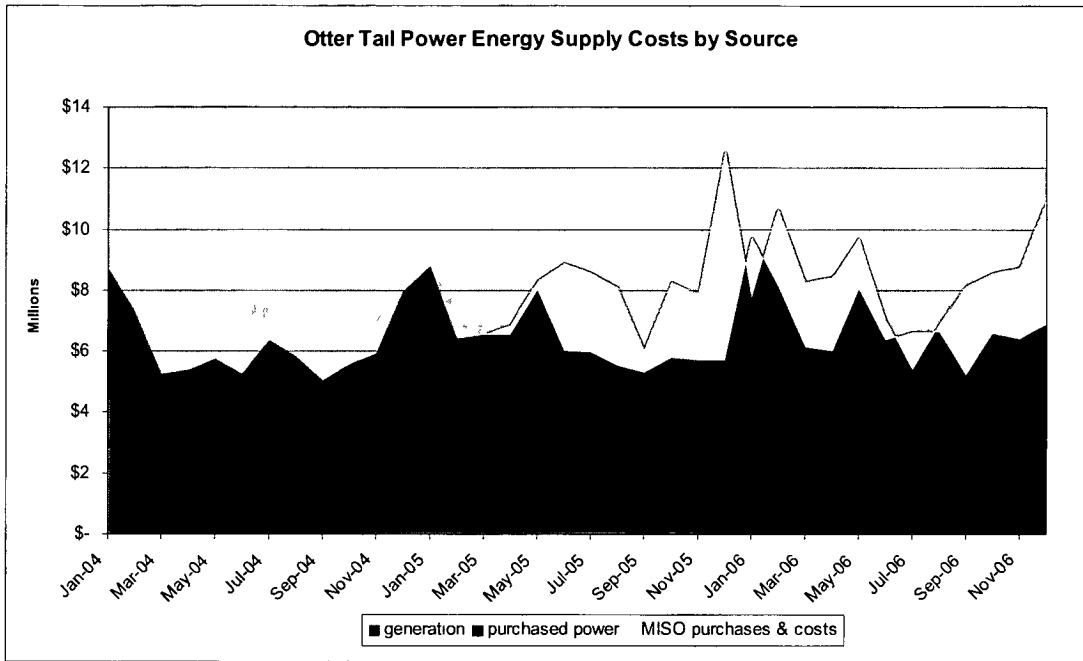
Base Cost per kWh \$ 0 016473

Energy Cost Adjustment -- Per kWh \$ 0 0181

TRUE UP FOR FEBRUARY

1) Net Energy (kWhs) Less 12% Losses	312,455,653
2) Net Energy Costs for the System -- Most recent month	\$ 11,937,784
3) Base Cost Recovered (1 X Base Cost of Fuel)	\$ 5,147,082
4) Net to be Recovered from COE (2 - 3)	\$ 6,790,702
5) COE Recovery Rate Effective for February	\$ 0 0138
6) Amount Recovered by COE (5 X 1)	\$ 4,311,888
7) Over / (Under) Recovery (4 - 6)	\$ (2,478,814)
8) Cumulative Over / (Under) Recovery	\$ (4,929,577)







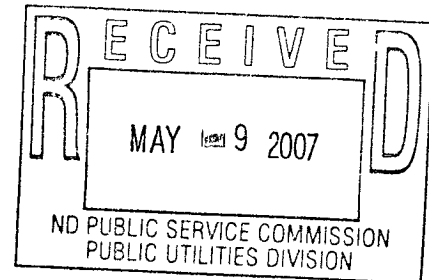
Fargo office 4334 18th Avenue S W
Suite 200, PO Box 9156
Fargo, ND
58106-9156
Fax 701-232-4108

Fergus Falls office 215 S Cascade Street
PO Box 496
Fergus Falls, MN
56538-0496
Fax 218-998-3165

1-866-410-8780 • www.ottertail.com

May 8, 2007

Mr. Thomas D. Kelsch
Kelsch Kelsch Ruff & Kranda
103 Collins Avenue
P.O. Box 1266
Mandan, ND 58554-7266



Mr. Jerry Lein
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismark, ND 58505-0480

Re: MISO Day 2 Costs-Costs of Fuel Adjustment Clause Tariff NDPSC Case No. PU-05-131

Dear Mr. Kelsch and Mr. Lein:

I am writing to confirm that the below-described issues accurately reflect the only open issues needing resolution through the evidentiary process in the above-referenced proceeding.

As you may recall, in a letter dated March 8, 2007, I set forth the agreements reached in the scheduling conference in the above-referenced matter. One of the agreements states:

Narrowing the Issues

The Intervenors, upon receipt of Otter Tail's discovery responses, will endeavor to narrow the issues in dispute in this matter so that the scope of the testimony, rebuttal and other preparations can similarly be narrowed. Once the issues are narrowed, Intervenors will communicate the remaining issues to Mr. Lein so that he may prepare and publish appropriate hearing notice for this matter.

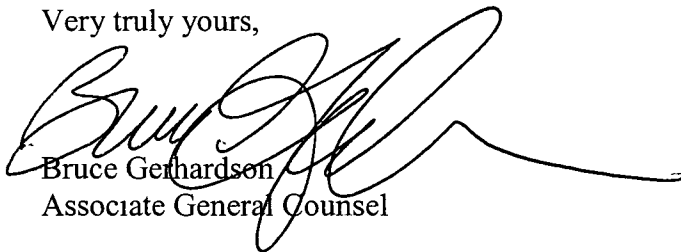
While Intervenors have filed testimony by Mr. Larry Schedin and Ms. Kavita Mami, that testimony does not contain a specific statement of open issues. However, based on that testimony Otter Tail has identified the following open issues:

1. Does the monthly variability in the fuel clause adjustment indicate either that the market is not working properly or that Otter Tail is not properly managing its market participation? If the answer to the question is yes, what should be required of Otter Tail?
2. Are differences between monthly retail system energy requirements and measured load an indication of a problem? If the answer is yes, what should be required of Otter Tail?

3. Should asset-based and non-asset based margins received since the inception of MISO Day 2 (April 2, 2005) be credited to the fuel clause adjustment?
4. Should Schedule 16 and 17 charges be recovered through base rates rather than in the FCA. If the answer is yes, should the Company be allowed deferred accounting for all refunded and otherwise unrecovered Schedule 16 and 17 charges until its next rate case?
5. Should the Company be required to report for its North Dakota operations the same FCA and MISO information as it is required to report in Minnesota?
6. When FCAs vary significantly from FCA forecasts, should the deviations be explained and re-forecasts submitted?
7. Are hidden capacity costs being passed through the FCA that should be removed?
8. Should Otter Tail hedge against natural gas costs?

Please respond immediately if these are not the issues as you see them.

Very truly yours,



Bruce Gerhardsen
Associate General Counsel



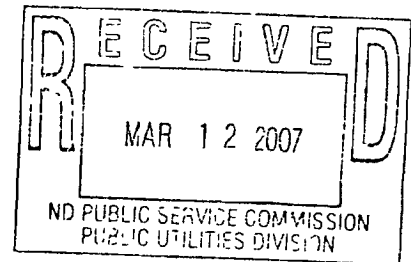
Fargo office: Fergus Falls office
4334 18th Avenue S W 215 S Cascade Street
Suite 200, PO Box 9156 PO Box 496
Fargo, ND Fergus Falls, MN
58106-9156 56538-0496
Fax 701-232-4108 Fax 218 998-3165
1-866-410-8780 • www.ottertail.com

March 8, 2007

Reply to Fergus Falls office
Direct: 218-998-7108

Mr. Thomas D. Kelsch
Kelsch Kelsch Ruff & Kranda
103 Collins Avenue
P. O. Box 1266
Mandan, ND 58554-7266

Mr. Jerry Lein
North Dakota Public Service Commission
600 E Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480



**Re: MISO Day 2 Costs - Cost of Fuel Adjustment Clause Tariff
NDPSC Case No. PU-05-131**

Dear Mr Kelsch and Mr Lein:

This letter confirms the agreements we reached in our scheduling conference in the above-referenced matter, which was held on February 28, 2007.

Schedule

The procedural schedule will be as follows:

April 20, 2007 – Due date for prefiled written direct testimony from Intervenors.

May 14, 2007 – Due date for prefiled written rebuttal testimony from Otter Tail

May 22, 2007 – Hearing at NDPSC

Discovery

We will respond to your February 21, 2007 discovery requests on or before March 20, 2007. We will also, before that time, as soon as practicable, provide you with any questions we may have on your interrogatories so that we may provide as full an answer as possible. Also, Otter Tail will provide, as soon as practicable, comments regarding interrogatories for which Otter Tail would not have the information requested (such as if the data would be in the possession of MISO rather than in the possession of Otter Tail, etc.).

It is possible that Otter Tail may have interrogatories or other discovery that it wishes to conduct after seeing the prefiled direct testimony from the Intervenors. You have agreed on behalf of the Intervenors to respond as quickly as possible to any such discovery requests in order that Otter Tail

Mr. Kelsch
Mr. Lein
March 8, 2007
Page 2

might have the benefit of those responses several days in advance of its May 14, 2007 filing of prefiled rebuttal testimony.

Finally, while we did not discuss this during the telephone conference, it is my belief that we should immediately work toward an acceptable Confidentiality Agreement for any trade secret or otherwise confidential information that may be filed in this matter. Given the sensitive nature of some of the data, I believe it is quite likely we will need to file some information as confidential, trade secret information

Narrowing the Issues


The Intervenor, upon receipt of Otter Tail's discovery responses, will endeavor to narrow the issues in dispute in this matter so that the scope of the testimony, rebuttal and other preparations can similarly be narrowed. Once the issues are narrowed, Intervenor will communicate the remaining issues to Mr. Lein so that he may prepare and publish an appropriate hearing notice for this matter.

May 22, 2007 Hearing

The Intervenor will present live testimony from their witnesses first, and Applicants will provide live testimony from their witnesses second. Live testimony will consist of a summary of the prefiled written testimony and surrebutal will be presented live, but will be limited to a response to the most recently tendered testimony (for Intervenor, surrebutal will be limited to a response to Otter Tail's prefiled written rebuttal, and for Otter Tail, surrebutal will be limited to a response to Intervenor's live surrebutal testimony). Limiting surrebutal in this fashion is intended to alleviate any concern that any party may raise new issues on the stand that were not raised in previous rounds of testimony. It is our expectation that the Administrative Law Judge will rule on beyond-the-scope objections consistent with this agreement.

It is our understanding that you, Jerry, will file this letter and that either it will have the same power and effect as a formal scheduling order, or you will obtain a formal scheduling order consistent with these terms

Sincerely,



Bruce Gerhardson
Associate General Counsel
BG/dm

c: Pete Berthon
Bernadeen Brutlag

Kelsch Kelsch Ruff & Kranda

C F Kelsch
1890-1987

Attorneys at Law
Mandan, North Dakota

William C Kelsch
Retired

THOMAS F KELSCH
ARLEN M RUFF, P C
THOMAS D KELSCH, P C
TODD D KRANDA, P C *
WILLIAM J DELMORE
DANIEL NAGLE

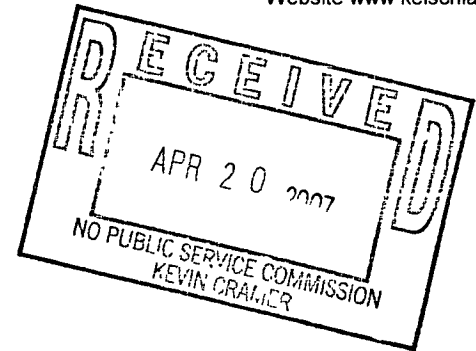
 MERITAS LAW FIRMS WORLDWIDE

103 Collins Avenue
P O Box 1266
Mandan, ND 58554-7266
Phone (701) 663-9818
1-888-663-9818
Fax (701) 663-9810
Website www.kelschlaw.com

*Also Licensed in Minnesota

April 20, 2007

ILLONA JEFFCOAT-SACCO
ND PUBLIC SERVICE COMMISSION
600 E BOULEVARD AVE
BISMARCK ND 58505-0480



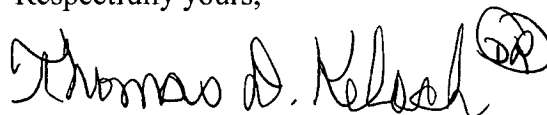
RE: Case No. PU-05-131
NDPSC
Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
Direct Testimony of Larry L. Schedin PE & Direct Testimony of Kavita Maini
Our File No. 12039

Dear Ms. Jeffcoat-Sacco:

I am enclosing an original and 7 copies of the Direct Testimony of Larry L. Schedin PE with Resume of Larry L. Schedin & Direct Testimony of Kavita Maini with Exhibits 1, 2 & 3 and Resume of Kavita Maini in the above case no. PU-05-131 on behalf of ND OTP Large Industrial Energy Group and an Affidavit of Service by Mail and Facsimile.

If you have any questions, please give me a call.

Respectfully yours,



Thomas D Kelsch

TDK:dr

Enclosures

cc: Eric Hoegger, Cargill, Incorporated
Steve Otto, Imation
Larry Schedin
Kavita Maini
Chuck McFarlane, Otter Tail Corporation
Bruce Gerhardson, Otter Tail Corporation
Allen C. Hoberg (fax: 701-328-3254)



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Pages 37

Direct testimony of Larry L. Schedin and
Kavita Maini
by Kelsch Kelsch Ruff & Kranda

04/20/2007 Comm, Legal Illona, Annette Mike, ALJ

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE)
COMMISSION OTTER TAIL CORPORATION)
COST OF FUEL ADJUSTMENT CLAUSE)
TARIFF)

Docket No. PU-05-131

DIRECT TESTIMONY OF LARRY L. SCHEDIN PE

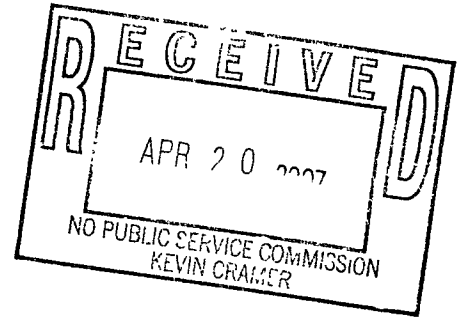


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I. Introduction

Q. Please state your name and occupation

A. My name is Larry L Schedin. I am a registered Professional Engineer. I am the president and owner of LLS Resources, LLC.

Q. Please state your business address.

A. My office is located at 12 South 6th Street, Suite 1137, Minneapolis, Minnesota, 55402

Q. Please state your educational and professional background.

A. Please see the summary of my educational and professional experience attached as LIG Exhibit (or Attachment?) No.1.

Q. Have you ever testified in other utility proceedings?

A. Yes, in numerous cases, in Federal, state and local proceedings.

Q. Has any of your recent experience been closely related to this current case before the NDPSC?

A. Yes. I was recently an expert witness for the Minnesota Chamber of Commerce (MN Chamber) in Xcel Energy's general rate case, MPUC Docket No. E-002/GR-05-1428, in which I analyzed the impact of the MISO Day 2 market on Xcel's retail Fuel Cost Adjustment (FCA). As a participant in this case I assisted the MN Chamber in reaching a settlement on this issues and others, including the sharing of wholesale margins.

Q. Has any of your recent work included participation with OTP?

A. Yes. As follow-on to my work on the Xcel Rate case, I participated as a MN Chamber representative in the MISO Stakeholder Group set up as an attempt to reach a settlement in MPUC Docket No. E-002/M-04-1970. OTP was a member of the Stakeholder Group along with the three other Minnesota IOU's all impacted by MISO related FCA issues.

Q. Did the Stakeholder Group, including OTP, reach a settlement which was adopted by the MPUC.

A. Yes. Much of the settlement was patterned after my rate case settlement with Xcel Energy

Q. Did the settlement include a sharing of wholesale margins?

A. No. However, both Xcel Energy and Alliant Energy had settled their wholesale margin sharing issue in their respective rate cases, and the MPUC has noted that wholesale

margin sharing will be an issue for OTP in their general rate case to be filed with the MPUC by October 1, 2007.

Q. What is the purpose of your testimony in this case?

A. My testimony examines OTP's request to recover all of its MISO Day 2 Market costs via OTP's FCA along with its current practice of sharing its wholesale trading margins. My testimony includes analysis, conclusions and recommendations regarding OTP's request and related practices impacting OTP's FCA and treatment of its retail customers.

Q. Have you worked with other witnesses in preparing your direct testimony in this case?

A. Yes, I worked with Kavita Maini, an associate in Oconomowoc, Wisconsin. She is a senior rate economist who has an extensive analytic background and knowledge of the MISO Day 2 Market.

Q. Has Ms Maini also submitted direct testimony in this case?

A. Yes. Her testimony is submitted as a separate exhibit. Her testimony includes analytic analyses upon which some of my conclusions and recommendations are based.

II. Background of Proceeding

Q. Please state your understanding of the background of this proceeding.

A. The proceeding background is as follows:

1. On March 1, 2005 OTP filed requested revisions to its FCA which would allow OTP to recover its MISO Day 2 Market costs via the revised FCA. The Commission suspended the requested tariff revisions on March 9, 2005. The new market began operations on April 1, 2005. OTP has participated in the market since its startup.
2. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing the recovery of costs from the Midwest ISO's new Day-2 energy market through fuel cost adjustments (FCA). The Commission's consolidated order states that sufficient Day-2 operational experience and market maturity would be necessary before adopting any permanent accounting treatment.
3. The Commission order states that FCA recovery of Day-2 Market costs is authorized on an interim basis and that the recovery of net Day-2 costs will be subject to refund plus interest if the Commission ultimately orders different accounting practices. Compliance tariff changes to standardize language in FCA tariff schedules were approved on an interim basis for all three North Dakota IOU's during July, 2005.

4. (Larry, I got this observation by reviewing the staff report..First page summary..Please review the first page and let me know if you agree with this observation)During August, 2006, the Commission Staff began reviewing the first three months of

MISO Day 2 Market costs according to the 32 cost categories as well as following re-settlement of certain MISO charge types. A Staff report regarding OTP was presented on December 8, 2006.

5. At present, Schedule 16 & 17 charges (market administration) as well as other uplift and RSG charges are all recovered via the FCA.

III Summary and Recommendations

Q. Please state your summary and recommendations.

A. My summary and recommendations are as follows:

A. Base Load Fuel Costs

The load duration curve and base load fuel cost analysis in Kavita Maini's testimony shows that OTP's base-load units supply about 85% of OTP's retail customer energy requirements at coal costs that have remained quite stable. OTP's 2006 coal costs expressed in cents per KWH are only 4.3% higher than in 2005 thereby eliminating coal cost changes as major factors in FCA volatility.

B. FCA Volatility

OTP's use of a four-month average FCA covers up true month-to-month variations in the FCA via smoothing. Our de-averaged FCA analysis shows extreme volatility in monthly FCA's with respect to the 1.65 cents per KWH base fuel cost embedded in base rates. Our analysis shows swings in the monthly FCA as high as 300% or more of the base embedded fuel cost even though OTP's base-load coal-fired units provide about 85% of OTP's retail energy requirements. Kavita Maini's use of hourly interval data to test the retail sales volumes used in the FCA also shows great disparities. This indicates that the market is not working properly for OTP's retail customers either because OTP is not properly managing its market participation or because OTP is charging costs without offsetting benefits to its retail customers.

OTP essentially entered the Day 2 market unprepared because it did not conduct any of its own impact studies prior to market startup. If OTP is unable to manage its market participation and accounting to eliminate these unreasonable swings and retail customer impacts, the Commission select a major accounting firm with no connection to OTP to review and correct OTP's market strategy and accounting (at OTP's expense) in order to ensure the lowest possible market-related FCA costs to OTP's retail customers. An outside accounting firm could also check for possible pass-through of hidden capacity costs which the FCA does not allow.

C. Wholesale margin sharing

OTP used wholesale trading margins of \$29.9 million in 2005 and \$16.0 million in 2006 to increase shareholder earnings (apparently the result of an astute and effective trading staff) to increase shareholder earnings. It is the opinion of the Large Industrials that keeping the margins to boost ROE completely contradicts good management practice. OTP took advantage of a new market with virtual trades and other trading practices and used the profits to boost shareholder earnings at the expense of its retail customers while claiming good management. Retail customers were forced to pay all of the out-of control FCA cost swings while receiving no credits. The opinion of the Large Industrials is that this is bad management. While good performing traders should be rewarded via salaries and other incentives, OTP's asset-based margins are made possible by selling output from generation paid for by OTP's retail ratepayers. Non-asset based margins are made possible by OTP trading staff members whose salaries and benefits are paid for by retail customers. Therefore, all the margins since market startup should be refunded to OTP's retail customers via the FCA rather than used to increase earnings. Additionally, all future wholesale margins should be passed on to retail ratepayers via the FCA. Because the present proceeding makes major changes to OTP's FCA, the Settlement Agreement and Revised Performance-Based Ratemaking (PBR) Plan in NDPS Case No. PU-401-00-36 should not be used as a basis for utilizing trading margins for increasing OTP's ROE. That earlier Agreement clearly states in Sec 10(A), entitled "Fuel Clause Adjustment":

"This Agreement and the Company's revised PBR does not change the Company's existing fuel clause adjustment (FCA) mechanism in its North Dakota Electric Rate Book tariff schedules"

This clearly indicates that the FCA change which OTP has filed was not anticipated in the PBR Plan.

D. MISO Market Management Transparency to Retail Customers

OTP's management should be held accountable for reporting and controlling its FCA costs. As part of this responsibility, OTP should provide to its Large Industrial customers and the Commission FCA projections to which it can be held accountable. For example, as OTP relates in its response to Large Industrial Interrogatory No. 25, it has not hedged any natural gas purchases even though it consumes large volumes in its Solway combustion turbine plant. When actual FCA's vary significantly from forecasted FCA's, deviations from forecast should be explained, and re-forecasts should be submitted. OTP should therefore conform to the same FCA reporting and MISO pass-through requirements to which they are now held responsible in MN. Since OTP already prepares the reports for its MN jurisdiction, no additional report preparation would be involved. (Note: If the MN consensus is not adopted in ND, the ND Commission could order a similar stakeholder process in ND). If the PBR Ratemaking plan is continued, OTP's

proper management and control of fuel and purchased energy costs, as expressed via the FCA, should be one of the most important performance criteria.

E. Staff report

The Large Industrials agree with the staff report conclusion that OTP should file a general rate case in North Dakota as soon as practicable, but we disagree that OTP should be allowed to recover MISO Administrative costs, charge types 16 and 17, via the FCA. Like other utility administrative costs, these charges are not part of energy costs and should be recovered in base rates via a rate case. The Large Industrials agree with the staff report that wholesale margin sharing should be given prompt attention, but we disagree that this important issue should be put off until OTP's next rate case. Margin sharing should begin as a result of the Commission's order in this present case. We also agree with the staff report conclusion that on a marginal cost basis that wind energy is substantially less expensive than energy from gas-fired turbines. However, wind turbines have a capacity factor of only 35-40% thereby requiring gas-fired combustion turbines and other generating units to be constructed in any event as back-up power sources. Although wind turbines have great benefits with respect to air emissions and should be constructed in any event, wind turbines are not necessarily a lower cost alternative on a total cost basis and are unlikely to reduce natural gas use during peak load periods. Therefore, natural gas cost hedging remains an important part of fuel cost management.

IV. Analysis of Issues

A. How the MISO Day 2 Market Works.

Q. Please explain briefly how the MISO Day 2 Market works.

A. A brief overview of the MISO Day 2 Market is as follows:

1. ND IOU's (OTP, NSP and MDU) as well as its municipal and cooperative Generation and Transmission (G&T) providers are fully engaged in the Midwest Independent System Operator (MISO) Day 2 Day-Ahead Market run out MISO's headquarters at Carmel, Indiana. The market is an energy-only spot market. Prior to 10:00 AM central standard time each day, each participating utility separately offers each of its generators each hour into tomorrow's market (at the generator's cost to start up, run and shut down) along with its request for bids to meet its hourly load forecast.
2. All the offers from all the utilities in the MISO Day 2 Market footprint are then stacked each hour in merit order (order of cost). A clearing price is established hourly at the price of the lowest marginal cost resource (plus losses) necessary to meet the hourly load consistent with reliability and deliverability constraints (security constrained dispatch with market clearing price based on marginal cost of last unit placed in service). The entire day-ahead market is cleared hourly, and ALL generators are paid the price of the market clearing price necessary to serve

the market load for that hour and for that location regardless of the actual cost to run. Similarly, each utility which serves load, called a Load-Serving Entity (LSE) must bid their load into the market and must pay the market clearing price for that hour for receiving all of its energy needs to serve load from the market. Hourly market clearing prices, called Locational Market Prices (LMP's) are set separately at each load point and at each generator location.

3. Prior to 3:00 PM on the day bids are submitted, each utility is notified which units it must run tomorrow. With few exceptions, each utility must bid ALL of its load and ALL of its generation into the Day 2 Market. Because of losses incurred by shipping power around the grid and because of security (deliverability) constraints, MISO posts the separate nodal LMP's at approximately 1300 locations around the grid. The LMP's change every 5 minutes and are averaged hourly. As the following day unfolds, the Day 2 Market prices are replaced by the real-time prices, and utilities pay penalties based on the difference between their bids and offers and actual performance. Market participants can play the Day 2 Market against the Real-Time Market via virtual (dummy) bids and offers.
 4. The Real-Time Energy Market dispatch is also supported by a Reliability Assessment Commitment (RAC) process to ensure that sufficient generating capacity is on line for regulating and contingency spinning reserves as well as for load, all to meet real-time, security-constrained operating conditions.
 5. Market participants can hedge against transmission congestion cost penalties by purchasing Financial Transmission Rights (FTR's) in advance.
4. MISO Accounting
- a. MISO credits each generating market participant each hour with an amount equal to the market clearing price at each of its generating locations (the LMP) times the generator output at each location.
 - b. For an LSE participant, such as an IOU which also must serve its customer load, MISO charges an offsetting amount for the load cost each hour equal to the MWH of load times the market clearing price at the load location (the load LMP). Because of location differences, the load LMP is typically different from the generation LMP. The generating offer revenues and the load bid costs for the Day 2 Market are cleared and netted in the Day Ahead Asset Energy Account.
 - c. The net Day-Ahead cost is then billed to the market participant as one of the 32 MISO charge types.
 - d. As the Real-Time Market unfolds and to the extent that actual loads and generation differ from the corresponding bids and offers into the Day-2 Market, MISO records and nets the differences in the Real Time Asset Energy Account as one of the 32 MISO charge types.

- e. Beyond this basic accounting and because all utility resources and loads must be offered and bid into the market, the corresponding Market Participant is also billed or credited via other of the 32 MISO charge types. MISO accounting then becomes quite complicated as reflected in charge types such as Revenue Sufficiency Guarantees (RSG's), Uplift Charges, FTR charges and Account 16 and 17 administrative charges, etc. The Commission Staff Report includes a definition of each of the 32 MISO charge types.

5. Utility Accounting

- a. Since a utility cannot distinguish from hour to hour whether any of its generators is generating for the needs of its own retail customers or the needs of other market participants, each utility must create a supplemental accounting based on "what if" principles which allocates its lowest cost generation first to the needs of its retail customers.

B. OTP's Cost of Energy Adjustment Clause – commonly called OTP's Fuel Cost Adjustment (FCA) and Volatility.

Q. Please describe OTP's Cost of Energy Adjustment Clause and its volatility.

A. The Clause and its volatility are described as follows:

1. FCA Volatility. OTP's FCA is based on a 4-month moving average of fuel and purchased energy costs with the immediate preceding month excluded from the calculations. The 4-month average hides true monthly variations and volatility of the FCA, especially since startup of the MISO Day 2 Market in April, 2005. Our de-averaged analysis of the monthly FCA's prepared by Kavita Maini in her testimony shows a sharp increase in FCA volatility beginning with the MISO Day 2 Market startup . The analysis shows month-to-month swings as high as 5.25 cents per KWH which is over 200% of the embedded cost of fuel. The analysis also shows discrepancies in OTP's KWH and cost data. Both the volatility and the discrepancies are being hidden by the FCA averaging.

2. Volatility Conclusions. FCA volatility since MISO Day 2 Market startup clearly indicates that the market is not working properly for OTP either because OTP is not properly managing its market participation or because OTP is charging costs without offsetting benefits to its retail customers. OTP essentially entered the MISO Day 2 Market unprepared. OTP did not conduct any of its own impact studies prior to entering the market (see OTP response to Large Industrial Interrogatory No. 7)

3. Monthly Retail Sales Volume Discrepancies. The month-to-month changes in energy use do not compare consistently with energy derived from OTP's interval load data thereby indicating possible FCA numerical errors.

4. FCA Wording Error. Because of an error in the description of the months averaged, OTP has not been following their authorized FCA. Their correction request to the

Commission under this Case (prompted by Large Industrial interrogatories) decreases the months averaged from 5 to 4 with the immediate preceding month excluded. The long time period with incorrect interpretation concerns the Large Industrial Group. This will decrease the recovery lag time.

5. Hidden Capacity Costs . OTP's FCA allows pass through of purchased energy costs but does not allow pass-through of capacity costs. As OTP admits in its response to Large Industrial Interrogatory No. 4, the MISO market is a spot market based on marginal energy costs which in some cases may include hidden capacity costs. Before FCA pass through is allowed, capacity costs should be removed from MISO's marginal energy costs. OTP admits in its response to Large Industrial Interrogatory No. 5 that it does not know if other participants recover their capacity costs via market energy charges.

6. Impact on Large Industrials. Even when averaged, the hidden volatility and the likelihood of OTP's questionable market management means a loss of confidence by the Large Industrials accompanied by a strong likelihood of unnecessary added costs.

7. FCA Conclusions and Recommendations . OTP must be held accountable for their FCA which is out of control. MISO costs as well as fuel procurement, unit maintenance and fuel transportation costs should no longer be considered as costs beyond OTP's control and automatically passed through to its retail customers via the FCA. OTP must also be held accountable for the discrepancies and errors in its monthly FCA reports. We recommend that OTP be required to disclose its MISO Market strategy along with its management of fuel costs, capacity costs, and unit maintenance for Commission and Large Industrial scrutiny. Further accounting review may be necessary by an outside accounting firm.

C. Wholesale Trading Margins

Q. Please describe OTP's wholesale trading margins.

A. Based on OTP's response to our interrogatories, their wholesale margins are as follows:

1. Types of Margins and Amounts.

OTP separates its wholesale trading margins (profits) into two types: 1) asset based and 2) non-asset based. Asset-based margins are derived from selling excess capacity and energy from OTP's owned generating plants. Non-asset based margins are derived from buying and selling capacity and energy which is not related to OTP's owned generating plants. OTP's response to Large Industrial Interrogatory No. 20 shows the following wholesale margins for 2005 and 2006:

	<u>2005</u>	<u>2006</u>
Asset-Based	\$11,571,416	\$11,046,158
Non Asset-Based	\$18,353,356	\$5,002,751
Total	\$29,924,772	\$16,048,908

2. Present Application of Margins

In its response to Large Industrial Interrogatory No.24, OTP states that ND retail customers benefited from OTP's wholesale margins because the margins boosted OTP's ROE as allowed under PBR ratemaking and avoided a retail rate increase which would otherwise have been necessary. None of the margins were applied to reduce retail rates via the FCA.

3. Recommendation on Margins

It is the opinion of the Large Industrials that keeping the margins to boost ROE completely contradicts good management practice. OTP's traders took advantage of the new market via virtual trades and other trading practices and used the profits to boost earnings at the expense of its retail customers while claiming good management. Retail customers were forced to pay all of the out-of-control FCA cost swings while receiving no credits. The opinion of the Large Industrials is that this is bad management, and all the margins since market startup should be refunded to OTP's retail customers via the FCA. Additionally, all future wholesale margins should be passed on to retail ratepayers via the FCA.

D. MISO Stakeholder Procedure in MN (See MPUC Order for Combined Dockets for the four IOU's) OTP's MN Docket No. is E-017/M-05-284

Q. Please describe the MISO Stakeholder process used in Minnesota and the outcome.

A. The process and its outcome are as follows:

1. Procedure and Participation. The procedure in MN went beyond the typical Case procedure. After the Commission combined the four dockets, the four impacted IOU's, the industrial customers, the MN Chamber of Commerce, the Dept of Commerce, the AG's office and MISO all participated in a stakeholder process aimed at reaching a settlement. The process also included a tutorial session for the MPUC Commissioners and their staffs. After many meetings and much dialog the Stakeholder Group reached a consensus with only one exception being the AG's office concern regarding state vs federal jurisdiction. The Commission essentially adopted the Stakeholder Group's consensus settlement over the objection of the AG's office.

2. Basis for Consensus. The MN Stakeholder Group Basically adopted a settlement relating to MISO costs agreed upon by Xcel and interveners in Xcel's retail rate case as initially proposed by the MN Chamber of Commerce. The consensus deals with all the MISO issues including ultimate sharing of wholesale margins.

3. The Agreement and MPUC Order.

a. Because most of the MISO costs in question are either fuel, purchased energy or

generator operating cost related, the order allows the pass-through of 30 of MISO's 32 charge types via the utility FCA's PROVIDED THAT THE COSTS ARE PRUDENTLY INCURRED. Also, definition of the 32 charge types are FERC approved.

- b. For the first time, commercial and industrial customers are given access to very important utility confidential information along with a process allowing them to challenge utility prudence regarding management of FCA costs and allowing them to budget for changes in FCA costs. THE ORDER EFFECTIVELY CONTRADICTS THE TRADITIONAL UTILITY POSITION THAT FCA COSTS ARE BEYOND MANAGEMENT CONTROL. Each IOU must greatly expand its annual FCA filing (called the AAA Report) and its monthly filings to include:
 - i. management strategy (quantified) to show how use of the MISO Day 2 Market, fuel procurement, fuel transportation and other related aspects of energy costs are being managed so as to minimize FCA costs.
 - ii. FCA forecasts to allow C&I customers the opportunity to better budget for FCA cost increases and decreases.
 - iii. Deviation explanation reports when actual FCA's exceed a threshold above forecast information.
 - iv. Re-forecasts of FCA's when deviations from forecasts (above a set threshold) significantly impact forecasts.
- c. IOU's must conform to a uniform supplemental accounting system to ensure that lowest-cost generation is first used to meet retail customer load.
- d. IOU's are limited regarding their risk in utilizing certain MISO Day 2 market transactions such as "virtual" transactions
- e. MISO administrative costs as reported under charge types 16 and 17 cannot be passed through the FCA. However, these costs can be accrued and deferred to the IOU's next rate case for possible future amortization to accounts recoverable from future retail ratepayers.
- f. At a time no later than their next rate case, MP&L and OTP must propose a plan for sharing their wholesale trading margins with their retail customers. Note: Under a separate order, OTP must file its next rate case in MN no later than October 1, 2007. Alliant Energy and Xcel's sharing plans have already been approved.

4. Conclusions and Recommendations. OTP should be held accountable for reporting and controlling its FCA costs. As part of this responsibility, OTP should provide to its Large Industrial customers and the Commission FCA projections to which it can be held accountable. For example, as OTP relates in its response to Large Industrial Interrogatory

No. 25, it has not hedged any natural gas purchases even though it consumes large volumes in its Solway combustion turbine plant. When actual FCA's vary significantly from forecasted FCA's, deviations from forecast should be explained, and re-forecasts should be submitted. OTP should therefore conform to the same FCA reporting and MISO pass-through requirements to which they are now held responsible in MN. Since OTP already prepares the reports for its MN jurisdiction, no additional report preparation would be involved. (Note: If the MN consensus is not adopted in ND, the ND Commission could order a similar stakeholder process in ND).

E. ND Commission Staff Report.

Q. Please explain your review and opinions regarding the North Dakota Staff report.

A. My review and opinions are as follows:

1. Timing

The ND Staff issued its Staff Report in OTP's Case No. PU-05-131 on December 8, 2006.

2. Recommendations

After displaying 17 graphs and figures showing OTP's MISO transactions and related materials, the ND Staff provided four recommendations as follows:

- a. Otter Tail should commit to a schedule for filing a general rate case as soon as practicable.
- b. Staff recommends continuing with the current FCA recovery process for Midwest ISO Day-2 market costs at this time. Staff does not recommend refunding and deferring schedule 16 and 17 charges for later rate case recovery because the money would have to be collected again through increased base rates, and then with a return on the deferral. The total amount of schedule 16 and 17 charges collected from North Dakota customers for the period under consideration in the staff report is approximately \$340,000.
- c. In Otter Tail's next general rate case, a sharing of wholesale margins through the fuel clause should be investigated. The Commission has addressed this issue with other utilities in the context of a general rate case.
- d. Otter Tail should continue to investigate cost-effective opportunities to displace purchases of energy produced from natural gas with less expensive wind energy.

3. Large Industrial Group Comments on Staff's Recommendations.

- a. The Large Industrial group agrees with the Staff's first recommendation that OTP should commit to a rate case as soon as practicable. Preparation can be consistent with

the upcoming MN rate case. However, we disagree with the remaining three recommendations.

b. The schedule 16 and 17 charges are not directly related to fuel and purchased energy and in that regard are no different from OTP's internal administrative costs which are not recovered via the FCA. Therefore the schedule 16 and 17 charges should be recovered in base rates during a general rate case.

c. The asset based wholesale margins are derived from assets included in OTP's rate base and paid for by retail customers. Therefore any margins derived from use of customer assets should be directly flowed through to retail customers beginning immediately (or retroactively?)

d. Wind turbines certainly have a place in OTP's generation mix, but wind turbines are not likely to reduce natural gas use which occurs during peak hours when wind output is likely to be low. Wind energy is more likely to reduce coal use. Also, when standby power and capital costs are considered, wind generation in total is likely to be more costly than natural gas fueled combustion turbines. Wind turbines will, however, always have lower marginal costs than gas-fired combustion turbines and are necessary to reduce air emissions.

e. The Staff report also indicates in Figures 4 and 5 that because of its extensive use of bilateral contracts, OTP has little Market exposure to MISO purchases. This conclusion is clearly misleading because all of OTP's resources are essentially cleared through the MISO Market even though bilateral settlements occur in parallel with the Market. As a result, bilateral contracts as well as OTP generation gather all types of MISO charges merely by being cleared through the MISO Market. See OTP response to Large Industrial Interrogatory No. 9.

Resume of Larry L. Schedin PE

Firm Name: LLS Resources, LLC

Address: 12 South 6th Street, Suite 1137
Minneapolis, MN 55402
Phone: (612) 343-8188

Title: _____ Owner _____

Total Professional Experience: 44 years

Education:

Masters Degree in Engineering Management - Massachusetts Institute of Technology,
Alfred P. Sloan Fellow, Massachusetts Institute of Technology
Bachelor of Electrical Engineering - The University of Minnesota
Graduate Study in Electrical Engineering – The University of Minnesota

Professional registrations and licenses:

Registered Professional Engineer, State of Minnesota - current
Lifetime Member of the Institute of Electrical and Electronics Engineers Inc.

Awards, publications, etc:

Published and edited “Energy Bulletin” a monthly energy news update for large energy users in the Chicago area, 1985 - 2000

VIII World Energy Conference Paper “Integration of Energy Resources in the North Central United States and Manitoba, Canada for the Production of Electrical Energy.” Presented in Bucharest, Romania, 1971

Massachusetts Institute of Technology Thesis: “Strategic Planning in the Utility Industry,” 1976

Laventhol & Horwath Perspective, Spring/Summer 1980, “Energy Management: An Accounting Approach to Cutting Costs” Co-authored with Miles H. Locketz and Richard M. Sherman

Previous Employment:

Larry L. Schedin started his own energy consulting business, Schedin & Associates Inc. in 1980 after 18 years with Northern States Power Company, a large electric and gas utility company serving over two million people in a four-state service area. His utility experience included a variety of management positions such as;

Director of Corporate Planning (1976-78)
General Manager of Rates (1971-75)
Manager of Power Supply Coordination (1970-71)
System Planning Engineer and other engineering positions (1961-70)

In 1998, Alliant Energy of Madison, Wisconsin purchased Schedin & Associates Inc and operated the business as part of their non-regulated consulting business subsidiary named Alliant Energy Integrated Services, LLC. Mr Schedin continued to manage the Minneapolis office for Alliant Energy until early 2004. In March, 2004 Mr. Schedin began a new business named LLS Resources, LLC where he continues to serve a broad range of commercial, industrial, institutional and utility clients

Brief Summary of Relevant Experience, including Special Achievements:

Mr. Schedin has taken an active role developing strategic energy plans, and advising industrial, utility, commercial and institutional clients as a technical consultant and an expert rate witness. One of his current emphases is on wind energy development. His clients include large corporations such as General Mills, Inc., American Crystal Sugar Company, CITGO Petroleum, Coca-Cola, the Minnesota Chamber of Commerce, the University of Minnesota and others. He also serves as an expert witness in utility regulatory proceedings both at the federal and state levels. Besides starting several businesses, Mr. Schedin's achievements include:

- Introduced the concept of contract renewable service in Minnesota to encourage customer ownership of wind farms in Minnesota, 2006.
- In cooperation with Caterpillar, CITGO Refining, General Mills Inc., Mobil Oil Refinery and others, Mr. Schedin helped form the Illinois Industrial and Institutional Customers for Electrical Restructuring (I³CER) Group to help draft the Illinois electric restructuring law, 1996 & 1997.
- In 1985, Mr. Schedin assisted a nucleus group of industrial customers to organize the Chicago Area Energy Users (CAEU) group with the purpose of improving the rates and policies of Northern Illinois Gas Company, Peoples Gas Light & Coke Company, North Shore Gas Company and Commonwealth Edison Company. Throughout the 1980's and 1990's this group helped to develop the new guidelines for delivering deregulated natural gas to the Chicago area. Mr. Schedin has continued to act as technical support advisor, counselor, organizer, administrator and energy expert for groups of customers who come together with a common need to understand the changing energy environment.
- Selected as technical advisor to The Minnesota Energy Consumers (MEC) Group, Minnesota's largest energy users in 1998.
- Testified before U.S. Congress House of Representatives.
- Testified before the Atomic Energy Commission (AEC), now the Nuclear Regulatory Commission (NRC).
- Testified before many state agencies regarding gas and electric utility rates, all on behalf of large energy users.

A detailed description of Mr. Schedin's expert witness and expert opinion experience is available upon request in a separate document.

1 **A. The purpose of my testimony is to describe the various tests that I**
2 **conducted in order to determine the reasonability of OTP's FCA**
3 **subsequent to OTP's participation in the MISO Day 2 market.**

4 **Specifically, I conducted the following tests:**

5 **1. The extent to which OTP's retail electric requirements are being supplied**
6 **by OTP's base-load generating units including Big Stone, Coyote and**
7 **Hoot Lake along with base-load coal costs expressed as \$ per KWH.**

8 **2. The extent to which OTP's remaining retail electric requirements are**
9 **being supplied by non base-load generation and the relationship of these**
10 **costs to OTP's FCA.**

11 **3. An analysis of de-averaged monthly incremental FCAs to identify the**
12 **level of volatility that is smoothed by averaging the FCAs over 4 months.**

13 **4. Comparison of monthly net generation applied in OTP's FCA**
14 **calculations to these same requirements developed from OTP's hourly**
15 **interval system load data.**

16 **5. Determination of whether all MISO related charges should be included in**
17 **the FCA**

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19 **Q. What are your conclusions from these analytical tests?**

20 **A. My conclusions are as follows:**

21 **1. For the months and years tested in 2005 and 2006, OTP supplied**
22 **over 85% of its retail requirements from its base-load generation.**
23 **Fuel costs from these coal-fired, base-load resources have been**
24 **very stable.**

25 **2. Of its 2005 and 2006 annual requirements, OTP would have**
26 **needed 14% and 13% respectively to fulfill system load**
27 **requirements through non base load generation, either from its**

1 **own peaking generation, purchased power from bilateral contracts**
2 **and/or purchases from the MISO Market.**

3 **3. My load duration curve analysis serves as a credibility check on**
4 **base-load generation costs. However, there is limited ability to**
5 **stack up the purchased power as well as purchases from MISO**
6 **under the load duration curve since the data provided by OTP for**
7 **non base-load resources does not lend itself to “cleanly” stacking**
8 **these other resources.**

9 **4. OTP has only limited ability to assure the Commission that its**
10 **retail system load requirements are being met with least cost**
11 **resources.**

12 **5. The current method of calculating FCAs over a 4-month period**
13 **significantly covers the underlying excessive monthly volatility.**

14 **6. Given the differential in OTP’s extensive base-load generation**
15 **costs and non base-load generation costs, it maybe appropriate to**
16 **differentiate day-time costs from night-time costs in the FCA.**

17 **7. There appears to be no consistent relationship between monthly**
18 **retail system energy requirements when measured from interval**
19 **load data load and from net generation shown on OTP’s FCA**
20 **calculations.**

21 **8. Schedule 16 and 17 charges are administrative charges and should**
22 **not be included in the FCA**

23 **9. Uplift charges such as Revenue Sufficiency Guarantee and**
24 **Revenue Neutrality Uplift should carefully analyzed and justified**
25 **before being be included in the FCA**

26 **Q. What was the method used to assess the percentage of system load**
27 **requirements to be met with resources other than OTP’s base-load**
28 **generation?**

29 **A. I used the following steps to make a credibility check on the amounts**
30 **of base-load generation used to supply OTP’s retail customer load:**

1 **1. Developed annual load duration curves for calendar years 2005 and**
2 **2006 respectively. This was done by using hourly load data provided**
3 **by OTP in response to interrogatory #18 (Attachments 18A and 18B)**
4 **and sorting the data from the highest hourly load to the lowest hourly**
5 **load for the specific time period**

6 **2. Stacked base load generation (least cost first) underneath each of the**
7 **curves using average annual base-load output derived from FERC**
8 **Form 1 reports**

9 **3. Calculated the amount of system load requirements that would need**
10 **to be fulfilled by non-base load owned generation.**

11 **Exhibits 1 and 2 (KMEXH 1&2) show the graphical results of the stacked**
12 **load duration curves for Calendar Years 2005 and 2006 respectively. Table 1**
13 **shows the tabulation of the system load requirements that were met by base**
14 **load generation and the net amount that would need to be fulfilled by**
15 **purchased power /purchasing through MISO.**

16

17 **Q. What implications can be drawn from this analysis?**

18 **A. As Table 1 indicates, for each of the calendar years, the system load**
19 **requirements are fulfilled by base load generation for over 85% for**
20 **Calendar years 2005 and 2006. Another key observation is that after**
21 **excluding the base cost of energy embedded in base rate of**
22 **\$0.016473/KWh, the remaining amount to be adjusted with an FCA**
23 **ranges from \$0.00064/KWh in 2005 to \$0.00138/KWh in 2006 on an**
24 **average annual basis. Note that this average incremental FCA is for**
25 **the base-load portion only. This shows that base-load cost impacts on**
26 **the FCA are minimal.**

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TABLE 1

**BASELOAD GENERATION, WEIGHTED COST AND % SYSTEM ENERGY REQUIREMENTS TO BE FULFILLED BY
PURCHASED POWER/MISO**

Annual	2005 Net Generation	Excess over load duration curve	Net Amt	FERC 1 Fuel Cost	with Losses	
Coyote	1,043,019,952	106,300	1,042,913,652	\$0 0101	\$0 0115	\$11,993,507
Big Stone	1,479,741,361	-	1,479,741,361	\$0 0161	\$0 0183	\$27,079,267
Hoot Lake	930,997,900	-	930,997,900	\$0 0189	\$0 0215	\$20,016,455
Total Baseload Gen (KWH)	3,453,759,213		3,453,652,913	Weighted Unit cost for baseload (\$/KWh)		\$0 01711
System Energy Requirements (KWH)			4,030,235,000			
System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)			576,582,087	Base Cost of Energy (embedded in rates)		\$0 01647
%System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)			14 3%	Amount to be recovered from FCA		\$0 00064
2006 Net Gen						
Annual	2006 Net Gen					
Coyote	981,477,885	124,000 00	981,353,885	0 0116	\$0 01318	\$12,936,028
Big Stone	1,669,980,759	-	1,669,980,759	0 0161	\$0 01830	\$30,553,057
Hoot Lake	869,741,600	-	869,741,600	0 0196	\$0 02227	\$19,371,517
Total Baseload Gen (KWH)	3,521,200,244		3,521,076,244	Weighted Unit cost for baseload (\$/KWh)		\$0 01785
System Energy Requirements (KWH)			4,060,037,000			
System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)			538,960,756	Base Cost of Energy (embedded in rates)		\$0 01647
%System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)			13 3%	Amount to be recovered from FCA		\$0 00138

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Source: FERC Form 1, OTP System Hourly Data

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Q. What major assumption is used in this analysis?

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A. This analysis assumes that the base load generation is the least cost dispatch as opposed to procuring net amounts from MISO during the majority of the hours. However, it is important to note that if it were cheaper to procure from MISO, then the majority of the load assumed to be fulfilled by the OTP's base load generation would be satisfied by resources whose weighted average costs would be less than those calculated in Table 1.

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Q. Why did you have to make this assumption?

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A. I had to make this assumption since there was no other discernable way to develop the stack without it. Pre-Day 2, it was relatively easy to

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stack up resources through generation and cost figures available from FERC Form 1. However, since OTP's participation in the Day 2 market and the complicated accounting associating with (a) procuring all native load requirements, (b) selling all energy from owned generation and (c) handling of purchased power deals, it has become extremely challenging to decouple and avoid double counting the trading activity and be able to discern whether OTP is serving its native load requirements with least cost resources.

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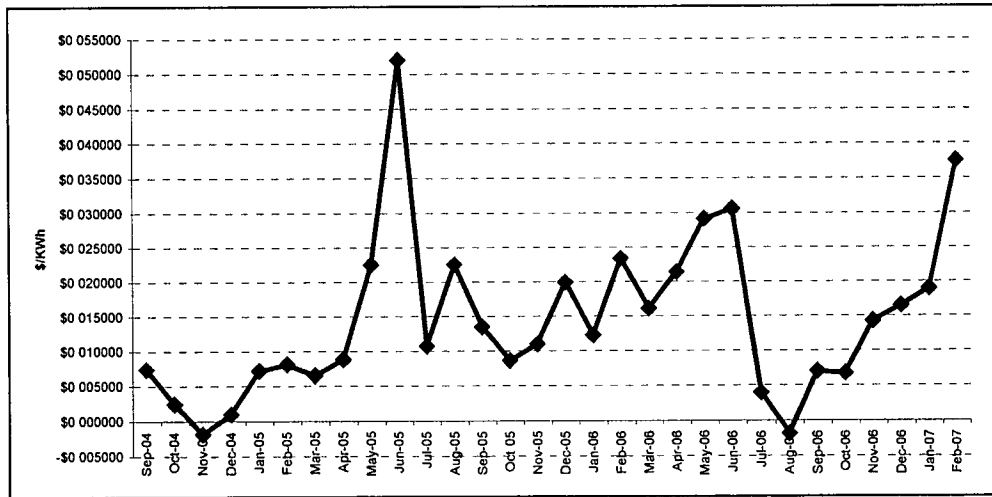
Q. What method was used to test and examine the 4-month cost of energy adjustments provided by OTP?

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A. I first de-averaged the cost of energy adjustments. By de-averaged, I mean calculating the fuel adjustments on a monthly basis. Using the information provided in Attachment 13-A (response to interrogatory #13 by OTP), the true up amount for each month was added to the energy charges and this total was divided by the net energy adjusted for losses. The base cost of \$0.016473/kWh was subtracted from the resulting number to arrive at the monthly *incremental* FCA. Exhibit 3 (KMEXH 3 entitled "Tabulation of de-averaged monthly FCAs) shows the monthly FCA numbers that were calculated.

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Figure 2: De-Averaged Monthly Incremental FCAs



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Q. What are your observations regarding this analysis?

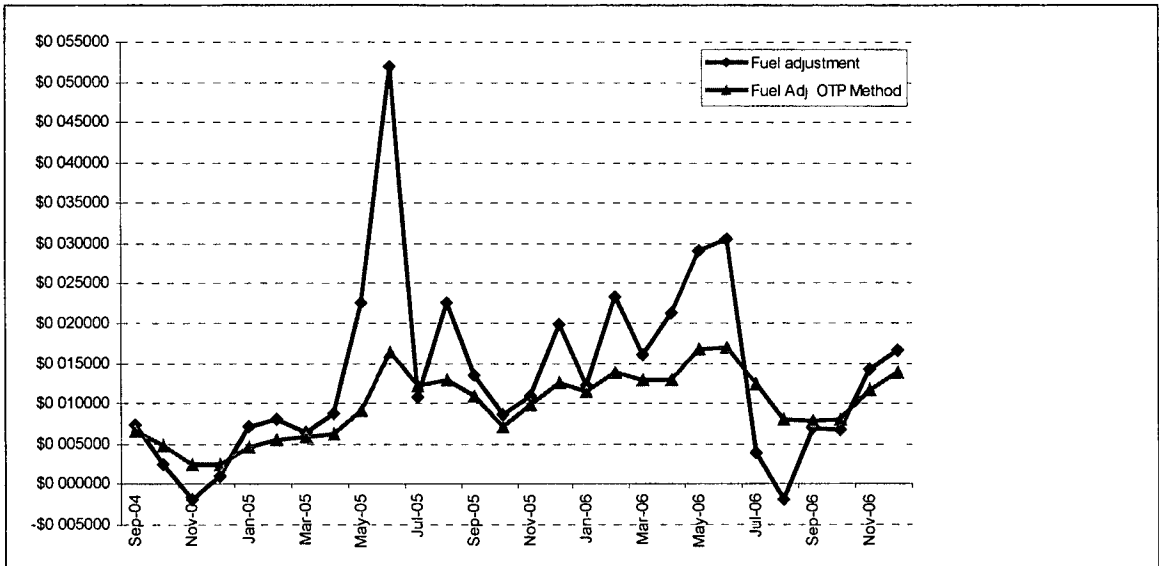
A. The following are my observations regarding this analysis:

- 1. High volatility gets hidden in the OTP FCA charges. As is apparent from Figure 2, there has been high volatility in the monthly incremental FCAs that get smoothed by averaging over a 4-month period. Note the jump in**

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June 2005 at 5.2 cents/kWh, which results after subtracting the base amount of \$0.016473/KWh. Figure 3 compares the de-averaged monthly FCA with the 4-month adjusted OTP FCA. This reinforces the observation that the volatility gets hidden and smoothed out when using a 4-month average. Data for 2007 indicates that the excessive volatility is still present and has not settled down.

Figure 3: Comparison of De-Averaged Monthly Incremental FCA And OTP's FCA

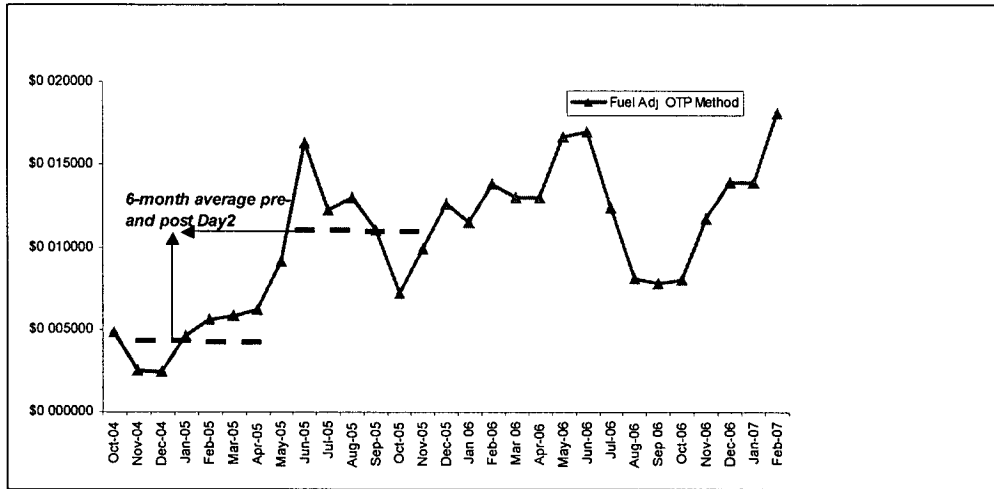


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2. *OTP's FCA indicates a significant increase beginning with The Company's participation in MISO Day 2 markets.* Figure 4 shows OTP's FCA trend and indicates 2 blue dashed lines that indicate the 6-month OTP's FCA average pre and post Day 2 markets. The average 6-month FCA goes up from \$0.004/KWh to \$0.0113/KWh, a 182% increase.

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Figure 4: OTP's FCA and 6-month Average FCA Pre- and Post-Day 2 MSIO Market



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Q. Was there a significant change in fuel costs associated with base-load generation?

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10. No. Figure 5 indicates the total monthly de-averaged FCA (i.e., include base cost of fuel @ \$0.016473/KWh) and shows dashed lines indicating average annual fuel costs associated with coal fired generation for 2004, 2005 and 2006 respectively. As the figure indicates, these fuel costs (obtained from FERC Form 1 data) did not change that significantly and do not appear to be the major driver for the high jump in the FCA. From 2004 to 2005, coal contract costs increased by 8.9% and from 2005 to 2006, the increase was 4.3%. Given the differential in OTP's extensive base-load generation costs and non base-load generation costs, it maybe appropriate to differentiate day-time costs from night-time costs in the FCA.

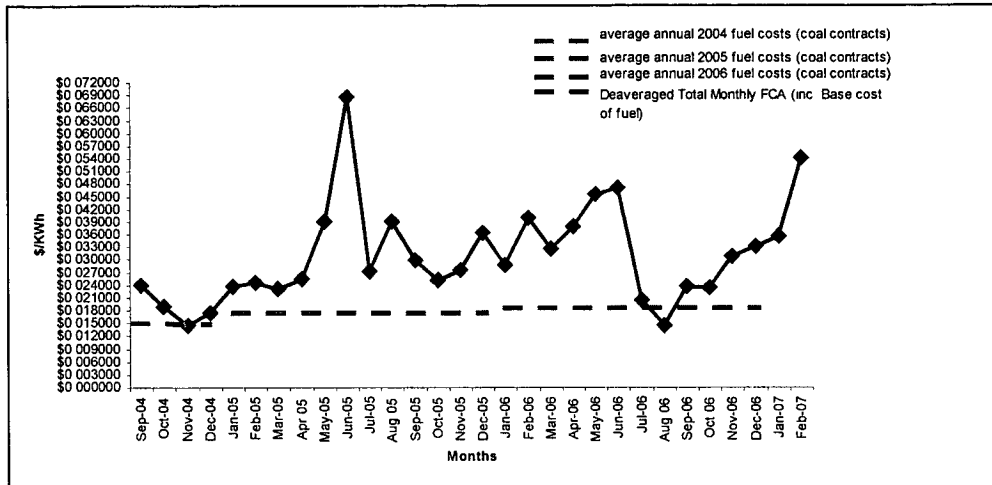
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Figure 5: Average Base-load Fuel Costs and Total Monthly De-averaged FCA (include base cost of fuel)

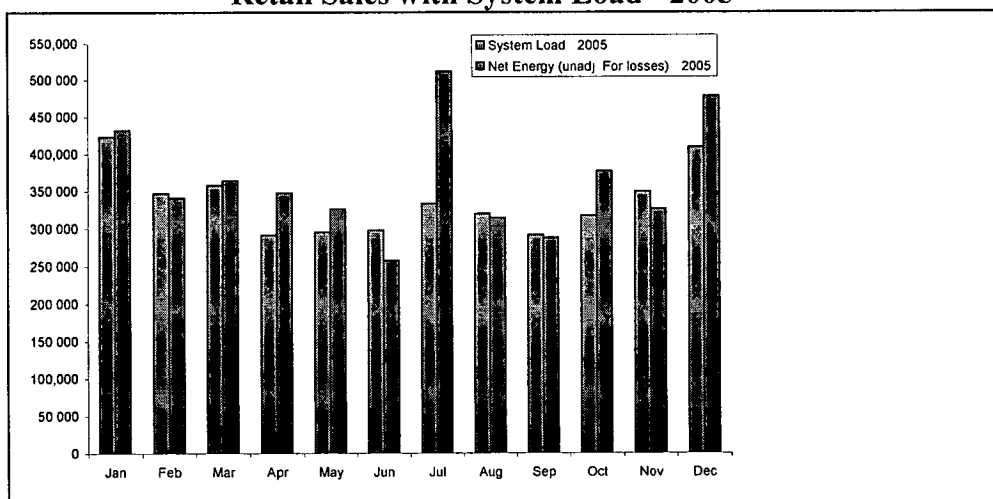


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Q. What data reasonability check did you perform regarding the net energy sales and system load data?

A. I compared net retail energy sales obtained from the FCA reports in Attachment 13-A (OTP interrogatory response) to the system load data obtained from Attachment 18 A and B (OTP interrogatory response). I found large differentials between the system load data and net retail sales in some months of the year. I expected that the net retail energy sales (unadjusted for losses and after accounting for intersystem sales) to serve load should more or less equal the system load. However, as Figure 6 indicates for 2005 and Table 7 indicates for 2005 & 2006, this is not the case. Note that there are several months each year where the differentials are 10% or higher in 2005 and 2006

Figure 6: Comparison of Monthly Net Energy Retail Sales with System Load - 2005



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Table 7: Comparison of Monthly Net Energy Retail Sales with System Load

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	SYSTEM LOAD- MWH		NET ENERGY (UNADJ FOR LOSSES)		% Difference (Net Retail Energy Sales - Sys Load)/ Sys Load	
	2005	2006	2005	2006	2005	2006
Jan	422,538	390,328	431,586	375,602	2%	-4%
Feb	346,769	380,025	340,595	381,558	-2%	0%
Mar	357,869	369,855	363,635	361,730	2%	-2%
Apr	291,114	284,629	347,466	316,567	19%	11%
May	295,261	297,409	325,878	326,110	10%	10%
Jun	298,122	288,064	257,512	260,428	-14%	-10%
Jul	333,094	339,260	511,933	307,227	54%	-9%
Aug	319,479	318,642	314,236	330,882	-2%	4%
Sep	291,373	285,260	287,737	295,938	-1%	4%
Oct	316,918	342,054	376,204	360,683	19%	5%
Nov	349,216	361,856	326,439	336,390	-7%	-7%
Dec	408,482	402,655	477,572	442,076	17%	10%

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There appears to be no consistent pattern/relationship in the differentials. This could perhaps be a symptom of deeper numerical errors in FCA calculations. Commission staff report refers to the large discrepancy in July 2005 as improper load accounting in April and May by OTP's own admission. However, there appear to be unsystematic differentials aside from the three months that were not explained.

Q. What MISO charges administrative or non-fuel related in nature appear to be passed through the FCA?

A. The following charges are administrative or non-fuel related in nature and appear to be passed through OTP's FCA:

1. *Schedules 16 & 17.* Schedules 16, and 17 associated with administrative costs related to ISO cost recovery for day ahead and real time markets as well as implementation of FTRs should be addressed under base rates as none of these costs are directly associated with "fuel". All MISO related costs that are non-transaction specific -- and, thus, not directly related to providing ratepayers with energy including, but not limited to charges under Schedules 16 and 17 should be addressed under the base rate. Under MISO related charge types, this would include the costs associated with:

- Day-Ahead Market Administration Amount.
- Financial Transmission Rights Market Administration Amount
- Real-Time Market Administration Amount

2. *Day ahead and real time sufficiency guarantee and make whole payments -* While the fuel component of the day ahead and real time revenue sufficiency guarantee payments could pass through in the FCA, the no-load and start-up costs should be addressed in a base rate case. Since a portion of the start-up costs are designed to recover maintenance expense, these costs -- no matter how minimal -- should be addressed in the base rate case.

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3. ***Real-Time Revenue Neutrality Uplift Amount.*** - This uplift amount is a balancing mechanism to assess costs or distribute revenues for which the MISO has no other method of assessing or distributing. These charges could have non-fuel components and should be addressed as part of a base rate proceeding.

EXHIBIT 1: Calendar Year 2005 - Stacked Load Duration Curve

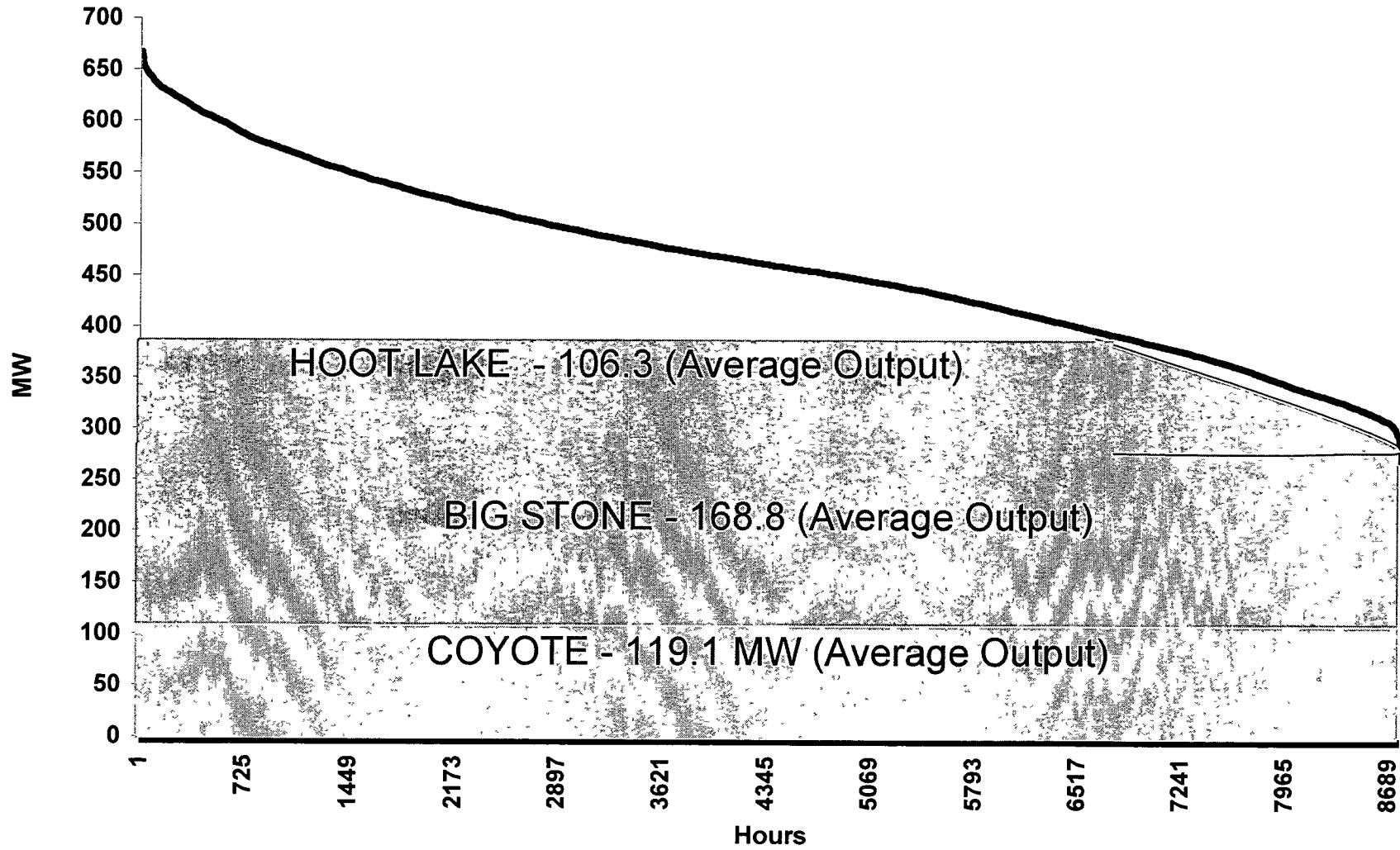


EXHIBIT 2:Calendar Year 2006 - Stacked Load Duration Curve

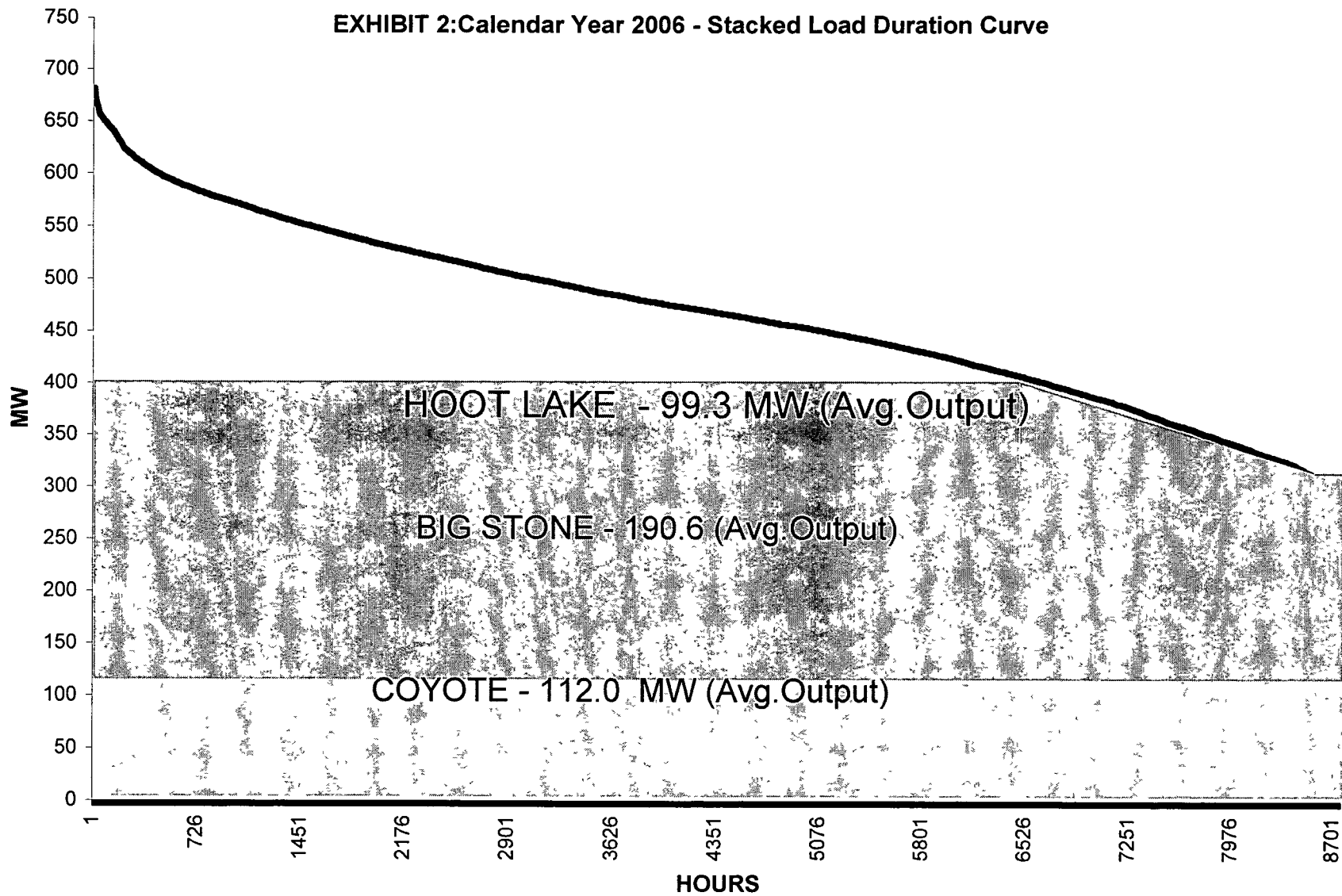


EXHIBIT - 3: Tabulation of De-Averaged Monthly FCA

	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05
Net Energy Costs	\$5,061,181	\$5,595,430	\$5,927,403	\$7,973,034	8,809,034	6,427,776	6,576,718	6,852,342
Prior (over) under recovery	1,114,768	(220,932)	(1,420,619)	(1,431,412)	171,757	942,847	776,229	879,303
Adjusted Net Energy Costs	\$6,175,949	\$5,374,498	\$4,506,784	\$6,541,622	8,980,791	7,370,623	7,352,947	7,731,645
Energy Usage (KWH)								
Total Energy	436,240,494	443,355,134	500,261,890	614,110,991	561,112,118	481,965,062	501,755,045	373,738,470
Less Intersystem Sales	-141,963,000	-120,199,000	-149,247,000	-187,630,000	-129,526,000	-141,370,000	-138,120,000	-95,113,000
Net Retail MISO Day 2								68,840,842
Net Energy - KW Hs	294,277,494	323,156,134	351,014,890	426,480,991	431,586,118	340,595,062	363,635,045	347,466,312
Adjusted for Losses	258,964,195	284,377,398	308,893,103	375,303,272	379,795,784	299,723,655	319,998,840	305,770,355
De-Averaged Total Monthly								
Fuel Adj	\$0 023849	\$0 018899	\$0 014590	\$0 017430	\$0 023646	\$0 024591	\$0 022978	\$0 025286
Base Cost \$/KWh	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473
De-Averaged Fuel Adj	\$0 007376	\$0 002426	-\$0 001883	\$0 000957	\$0 007173	\$0 008118	\$0 006505	\$0 008813

EXHIBIT - 3: Tabula

	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05
Net Energy Costs	8,338,142	8,909,886	8,581,245	8,088,312	6,073,931	8,281,197	7,875,151
Prior (over) under recovery	2,830,165	6,602,111	3,662,696	2,688,364	1,502,041	25,913	8,998
Adjusted Net Energy Costs	11,168,307	15,511,997	12,243,941	10,776,676	7,575,972	8,307,110	7,884,149
Energy Usage (KWH)							
Total Energy	380,502,392	467,226,557	526,543,694	465,629,853	437,731,807	600,232,516	545,500,472
Less Intersystem Sales	-106,829,000	-264,691,000	-173,071,000	-201,016,000	-196,985,000	-245,879,000	-282,733,000
Net Retail MISO Day 2	52,204,199	54,976,412	158,460,166	49,622,207	46,990,343	21,850,790	63,671,452
Net Energy - KW Hs	325,877,591	257,511,969	511,932,860	314,236,060	287,737,150	376,204,306	326,438,924
Adjusted for Losses De-Averaged Total Monthly	286,772,280	226,610,533	450,500,917	276,527,733	253,208,692	331,059,789	287,266,253
Fuel Adj	\$0 038945	\$0 068452	\$0 027179	\$0 038971	\$0 029920	\$0 025092	\$0 027445
Base Cost \$/KWh	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473
De-Averaged Fuel Adj	\$0 022472	\$0 051979	\$0 010706	\$0 022498	\$0 013447	\$0 008619	\$0 010972

EXHIBIT - 3: Tabula

	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06
Net Energy Costs	12,610,541	7,767,539	10,689,884	8,289,472	8,451,774	9,726,701	7,090,183	5,397,050
Prior (over) under recovery	2,670,635	1,721,114	2,682,703	2,067,748	2,086,102	3,354,738	3,690,404	118,799
Adjusted Net Energy Costs	15,281,176	9,488,653	13,372,587	10,357,220	10,537,876	13,081,439	10,780,587	5,515,849
Energy Usage (KWH)								
Total Energy	568,058,969	716,878,348	622,977,589	516,991,930	430,684,369	551,862,967	529,745,607	568,332,716
Less Intersystem Sales	-172,631,646	-364,215,889	-293,174,737	-203,169,398	-181,771,184	-253,976,985	-281,580,388	-227,131,932
Net Retail MISO Day 2	82,145,117	22,939,511	51,755,183	47,907,185	67,653,787	28,223,935	12,262,492	-33,973,410
Net Energy - KW Hs	477,572,440	375,601,970	381,558,035	361,729,717	316,566,972	326,109,917	260,427,711	307,227,374
Adjusted for Losses De-Averaged Total Monthly	420,263,747	330,529,734	335,771,071	318,322,151	278,578,935	286,976,727	229,176,386	270,360,089
Fuel Adj	\$0 036361	\$0 028707	\$0 039827	\$0 032537	\$0 037827	\$0 045584	\$0 047041	\$0 020402
Base Cost \$/KWh	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473
De-Averaged Fuel Adj	\$0 019888	\$0 012234	\$0 023354	\$0 016064	\$0 021354	\$0 029111	\$0 030568	\$0 003929

EXHIBIT - 3: Tabula

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07
Net Energy Costs	6,920,541	8,156,381	8,599,860	8,759,833	10,983,875	12,339,525	11,937,784
Prior (over) under recovery	-2,678,081	-2,040,973	-1,240,605	333,858	1,835,970	2,450,763	4,929,577
Adjusted Net Energy Costs	4,242,460	6,115,408	7,359,255	9,093,691	12,819,845	14,790,288	16,867,362
Energy Usage (KWH)							
Total Energy	638,154,126	510,923,962	667,052,322	482,231,589	870,121,872	549,546,724	388,786,400
Less Intersystem Sales	-298,826,865	-254,784,076	-340,048,851	-172,610,687	-479,628,604	-161,756,277	-103,506,006
Net Retail MISO Day 2	-8,445,300	39,798,529	33,679,371	26,769,020	51,583,215	86,813,595	69,782,848
Net Energy - KW Hs	330,881,961	295,938,415	360,682,842	336,389,922	442,076,483	474,604,042	355,063,242
Adjusted for Losses De-Averaged Total Monthly	291,176,126	260,425,805	317,400,901	296,023,131	389,027,305	417,651,557	312,455,653
Fuel Adj	\$0 014570	\$0 023482	\$0 023186	\$0 030720	\$0 032954	\$0 035413	\$0 053983
Base Cost \$/KWh	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473	\$0 016473
De-Averaged Fuel Adj	-\$0 001903	\$0 007009	\$0 006713	\$0 014247	\$0 016481	\$0 018940	\$0 037510



Protecting Your Bottom Line

961 North Lost Woods Road
Oconomowoc, WI 53066
kmains@wi.rr.com
Phone 262-646-3981,

KAVITA MAINI

Principal, KM Energy Consulting, LLC
Certified as a Minority Business Enterprise in Wisconsin

Core Competency: *Economist and extensive experience in electricity and natural gas pricing, market dynamics, procurement, regulatory and policy issues; Independent consultant working on behalf of retail customers*

2002 – Present: Independent Energy Consultant

Areas of Expertise

- RTO, Regulatory & Policy Issues
- Rate analyses, rate design
- Energy policy advising
- Energy price forecasting
- Energy procurement advising & contract negotiations
- Fuel and asset optimization studies, on-site generation feasibility
- Risk management & hedging strategies
- Strategic energy planning and best practices
- Educational workshops
- Due Diligence, Business/Strategic Plans & Market Research
- Support to Energy User Groups

Alliant Energy Integrated Services, WI, Energy Consulting Division, 1998 - 2002

Title: Senior Economist – Responsibilities

- Regulatory & rate analyses, rate design
- Energy policy advising
- Energy price forecasting
- Energy procurement advising & contract negotiations
- Fuel and asset optimization, on-site generation feasibility
- Risk management & hedging strategies
- Strategic energy planning and best practices
- Educational workshops
- Due Diligence on Acquisitions, Business/Strategic Planning & Market Research
- Support to Energy User Groups

Regional Economic Research, Inc., CA, 1997 – 1998

Title: Senior Analyst – Responsibilities

- Energy Market Profiles
- Various DSM Evaluations
- Forecasting using Neural Network Models

Wisconsin Power & Light Co., WI, 1991-1997

Title: Research & Senior Research Analyst -Responsibilities

- Impact evaluations for the commercial, industrial and residential programs
- Process evaluations for the commercial, industrial and residential programs
- Forward price curve and asset valuation analyses
- Market transformation analysis
- Market research, target market and segmentation analyses
- Monitoring and verification protocols for energy efficiency initiatives
- Merger related strategic planning & research

Education

- Bachelor of Arts Degree in English Literature and French from Sacred Heart College, Dalhousie, India, 1982
- Masters in Business Administration, Marquette University, Milwaukee, WI, 1986
- Masters of Science in Applied Economics, Marquette University, Milwaukee, WI, 1991
- Risk Management Workshops, Due Diligence for Mergers and Acquisitions Workshops

Recent Publications/Other

Energy Round Table, Expert Speaker, Corporate Report Wisconsin, November 2003.

Comments on PSC's Strategic Energy Assessment (Shaping Wisconsin's Energy Policy & Regulatory Process), July 2004 (One of the primary authors)

Participant, Workshops on Post 2006 Initiative in Illinois, 2004

Joint Comments on Strategic Energy Assessment – ATC long term expansion plan”, March 2005, Submitted to PSC - WI

Maini, Kavita et al, “*Joint Comments on PSCW's own investigation regarding Cost of Service and Rate Design Issues*”, August 2005 (*One of the primary authors*)

Maini, Kavita et al, “*Joint Comments on ATC's Access Initiative*”, September 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Joint Comments on PSCW's draft report on ATC's Access Initiative*”, September 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Comments on PSCW's Notice of Investigation on MISO Cost Categorization*”, November 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Comments on PSCW's draft Strategic Energy Assessment Report*”, 2006 Submitted to PSC – WI

Joint Comments with Midwest Industrials to FERC on MISO's proposed Ancillary Services Market, March 2007

Received 2005 Energy Engineer of the Year by the AEE Regional Chapter, Chicago, IL

Select Presentations/Workshops

CLASEC (Illinois) – Energy Deregulation and Pricing Trends

Association of Energy Engineers - Electricity Deregulation Options in Illinois

Corporate Report Wisconsin – Roundtable Discussion on Energy Related Issues

Wisconsin Public Utility Institute – Workshops on Integrated Natural Gas Planning, Energy Utility Basics

University of MN – Workshops on Energy Deregulation

Wisconsin Industrial Energy Group – Several Presentations

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE)
COMMISSION OTTER TAIL CORPORATION) Docket No. PU-05-131
COST OF FUEL ADJUSTMENT CLAUSE)
TARIFF)

STATE OF NORTH DAKOTA)
) ss. **AFFIDAVIT OF SERVICE**
COUNTY OF MORTON) **BY MAIL & FACSIMILE**

DEBRA K. ROEHRICH being first duly sworn, on oath, deposes and says: That she is a citizen of the United States, over the age of eighteen and not a party to the above-entitled action.

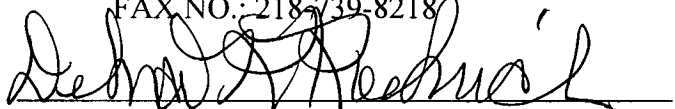
That on the 20th day of April, 2007, this affiant deposited in the United States Post Office at Mandan, North Dakota, and faxed a true and correct copy of the following document(s) in the above-captioned action:

- 1. Direct Testimony of Larry L. Schedin PE with Resume of Larry L. Schedin PE;
- 2. Direct Testimony of Kavita Maini with Exhibits 1, 2 & 3 and Resume of Kavita Maini.


That a copy of the above document(s) was securely enclosed in an envelope with postage duly prepaid, and addressed as follows:

CHUCK MCFARLANE
OTTERTAIL CORPORATION
215 S CASCADE STREET
FERGUS FALLS MN 56538
FAX NO.: 218-739-8218

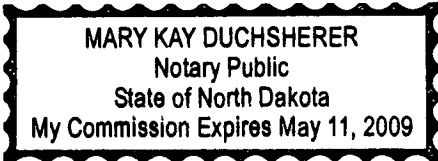
BRUCE GERHARDSON
OTTERTAIL CORPORATION
215 S CASCADE STREET
FERGUS FALLS MN 58538
FAX NO.: 218-739-8218


DEBRA K. ROEHRICH

Subscribed and sworn to before me this 20 day of April, 2007.


Notary Public, State of North Dakota

(SEAL)





North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185



INVOICE

Order **23287-07041PP0**

Invoice # **86428**

April 19, 2007

Attn: ILLONAA. JEFFCOAT-SACCO
PUBLIC SERVICE COMMISSION
600 E. BOULEVARD AVE.
STATE CAPITOL
BISMARCK, ND 58505

Advertiser **Public Utilities Division**

P O # **PU-05-131**

Amount Due **\$325.39**

Amount Paid

Voice 701-328-4076

Please detach and return this portion with your payment

Public Utilities Division Invoice # 23287-07041PP0-86428 PO# PU-05-131

Ad Size	Rate Type	Rate	Total	Discount (%)	Caption	Page	Run Date
Bismarck Tribune (Bismarck ND)							
60 00	SPR2	0 68	40.80	0 00	Otter Tail Cost of Fue		04/02/07
Devils Lake Daily Journal (Devils Lake ND)							
66 00	SPR2	0 62	40.92	0 00	Otter Tail Cost of Fue		04/02/07
Fargo, The Forum (Fargo ND)							
54 00	SPR2	0 76	41.04	0.00	Otter Tail Cost of Fue		04/02/07
Grand Forks Herald (Grand Forks ND)							
59 00	SPR2	0 71	41.89	0 00	Otter Tail Cost of Fue		04/03/07
Jamestown Sun (Jamestown ND)							
67.00	SPR2	0.58	38.86	0 00	Otter Tail Cost of Fue		04/02/07
Minot Daily News (Minot ND)							
76.00	SPR2	0 54	41.04	0 00	Otter Tail Cost of Fue		04/02/07
Valley City Times-Record (Valley City ND)							
62.00	SPR2	0.64	39 68	0.00	Otter Tail Cost of Fue		04/02/07
Wahpeton Daily News (Wahpeton ND)							
84 00	SPR2	0 49	41.16	0 00	Otter Tail Cost of Fue		04/03/07

Gross Advertising	325.39	Total Misc	0.00	Amount Paid	0 00
Agency Discount		Tax	0 00	Adjustments	0 00
Other Discount	0.00	Total Billed	325.39	Payment Date	
Service Charge	0 00	Unbilled	0 00	Balance Due	325 39

If you would like to pay this invoice with a credit card, please contact Rhonda at 701-223-6397

Affidavit of Publication

Colleen Park

, being duly sworn, state as follows.

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:

Public Service Commission, Otter Tail, Cost of Fuel,

1 time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed Colleen Park

State of N.D.

County of Burleigh

Subscribed and sworn to before me this 18th day of April 20 07.

Kerryman

KERRY AMAN
Notary Public
State of North Dakota
My Commission Expires Aug 17, 2012

State Of North Dakota
Public Service Commission
Notice Of Hearing
Case No. PU-05-131
March 21, 2009

Bismarck	4-2
Dickinson	—
Devils Lake	4-2
Fargo	4-2
Grand Forks	4-3
Jamestown	4-2
Minot	4-2
Valley City	4-2
Walpeton	4-3
Williston	—



Public Service Commission
State of North Dakota

COMMISSIONERS

Susan E Wefald, President
Kevin Cramer
Tony Clark

Executive Director
Ilona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www.nd.gov/psc
e-mail ndpsc@nd.gov
TTY 800-366-6888 or 711
Fax 701-328-2410
Phone 701-328-2400

April 19, 2007

Michael J. Bradley
Attorney At Law
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis MN 55402-4129

Re: Motion to Practice Before Commission
Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff
Case No. PU-05-131

Dear Mr. Bradley:

Enclosed is a copy of the Commission's Motion admitting attorney Michael J. Bradley to practice before the Commission in the above referenced case.

If you have any questions, please contact us.

Thank you.

Sincerely,


William W. Binek
Chief Counsel

enclosure

CC Bruce Gerhardson
Bernadeen Brutlag
Thomas D. Kelsch
Dave Sederquist
Megan J. Hertzler
Donald R. Ball
Daniel S Kuntz
Penny Miller, ND Supreme Court

35 PU-05-131

Pages 1

Letter response to admission to practice

by Public Service Commission

04/19/2007 Comm, Legal Ilona, Annette Mike, ALJ

April 13, 2007

Illona Jeffcoat-Sacco
North Dakota Public Service Commission
State Capitol
600 East Boulevard
Bismarck, ND 58505-0480



Re: In the Matter of the Petition of Otter Tail Corporation d/b/a Otter Tail Power Company
for Cost of Fuel Adjustment Clause Tariff
Case No. PU-05-131

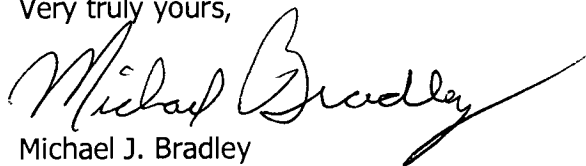
Dear Ms. Jeffcoat-Sacco:

Enclosed please find the original and seven copies of the Motion for the Admission Pro Hac Vice of Michael J. Bradley and the Affidavit of Michael J. Bradley in the above-entitled Docket.

Copies of the documents have also been sent to the State Board of Law Examiners, along with the appropriate fee, and to all counsel in this Docket.

Please contact me if further information is required.

Very truly yours,



Michael J. Bradley
Attorney At Law
(612) 877-5337
BradleyM@moss-barnett.com

MJB/jjh
Enclosures
cc: Parties of record
976990v1

33 PU-05-131

Pages 2

Cover letter and affidavit of service for the
filing
by Rural Telephone Company Group
04/13/2007 Comm, Legal Illona, Annette Mike, ALJ

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

In the Matter of the Petition of Otter Tail)
Corporation d/b/a Otter Tail Power)
Company for Cost of Fuel Adjustment)
Clause Tariff)

Case No. PU-05-131

CERTIFICATE OF SERVICE

Kim R. Manney, being first duly sworn, deposes and states that on the 13th day of April, 2007, copies of the Motion for the Admission Pro Hac Vice of Michael J. Bradley and the Affidavit of Michael J. Bradley on behalf of Otter Tail Corporation d/b/a Otter Tail Power Company in the above-entitled matter were mailed by United States first class mail, postage prepaid thereon, to the following:

✓ Bernadeen Brutlag
Manager – Regulatory Relations
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56537

Donald R. Ball
Vice President – Regulatory Affairs
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

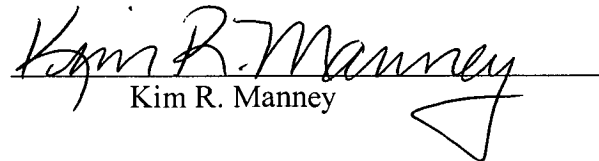
✓ Dave Sederquist
Senior Consultant – Regulatory & Finance
Xcel Energy
P O Box 2747
Fargo, ND 58208

Thomas D. Kelsch
Counsel for North Dakota OTP Large
Industrial Energy Group
P O Box 1266
Mandan, ND 58554-7266

Bruce Gerhardson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56537

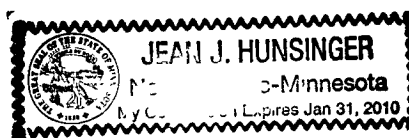
Daniel S. Kuntz
Associate General Counsel
Montana-Dakota Utilities Co.
P O Box 5650
1200 W Century Avenue
Bismarck, ND 58506-5650

✓ Megan J. Hertzler
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401


Kim R. Manney

SWORN TO BEFORE ME this
13th day of April, 2007.


NOTARY PUBLIC



**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

In the Matter of the Petition of Otter Tail)
Corporation d/b/a Otter Tail Power)
Company for Cost of Fuel Adjustment)
Clause Tariff)

Case No. PU-05-131

**MOTION FOR THE ADMISSION PRO HAC VICE OF
MICHAEL J. BRADLEY**

Pursuant to North Dakota Supreme Court Rule 3 and NDAC § 69-02-01-06, Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail Power") seeks leave of the North Dakota Public Service Commission ("Commission") to permit Michael J. Bradley to appear before the Commission to represent Otter Tail Power in the above entitled-Docket. Mr. Bradley will co-counsel with Bruce Gerhardson, in-house counsel to Otter Tail Power who is licensed to practice in North Dakota.

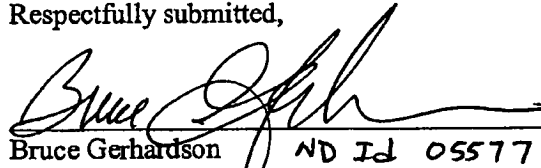
As stated in the attached Affidavit of Michael J. Bradley, he is admitted to practice and in good standing with the bar of the State of Minnesota, the Minnesota Federal District Court, the Eighth Circuit Federal Court of Appeals, and the U.S. Supreme Court. He is not subject to any disciplinary action in any jurisdiction, he is not under any restrictions or probation in the practice of law in any jurisdiction where he is licensed, and he is not suspended or disbarred from any court in any jurisdiction. He has not previously appeared before the Commission. Contemporaneously with this Motion for Admission, he is filing another Motion for Admission in another Docket.

Mr. Bradley has extensive experience in Minnesota representing clients with respect to fuel clause adjustment tariff and MISO cost recovery issues. His previous experience in these matters will assist the Commission with the issues of this Docket.

Mr. Bradley is a reputable attorney and the undersigned attorney recommends his admission to practice before the Commission in the above entitled Docket.

Dated: April 13, 2007

Respectfully submitted,



Bruce Gerhardson ND ID 05577
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56537

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

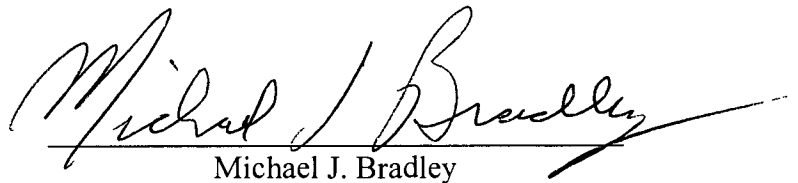
In the Matter of the Petition of Otter Tail)
Corporation d/b/a Otter Tail Power)
Company for Cost of Fuel Adjustment)
Clause Tariff)

Case No. PU-05-131

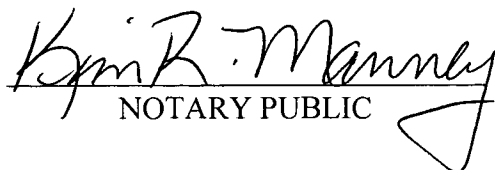
AFFIDAVIT OF MICHAEL J. BRADLEY

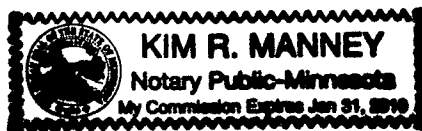
In support of the Motion for Pro Hac Vice, Michael J. Bradley, being first duly sworn on oath, deposes and states that:

1. My name is Michael J Bradley. I am a shareholder of Moss & Barnett, located at 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402
2. I am a member in good standing of the bar of the State of Minnesota since 1973, the Minnesota Federal District Court since 1973, the Eighth Circuit Federal Court of Appeals since 2005, and the U.S. Supreme Court since 1977.
3. I am not presently subject to any disciplinary action by the bar or courts of the State of Minnesota or of any other court, nor under any restrictions or probation in the practice of law in any jurisdiction where I am licensed. I have not been suspended or disbarred from a court in any jurisdiction.
4. I have not appeared before the NDPSC during the past three years, and have not previously registered under Rule 3 of the North Dakota Admission to Practice Rules. I am also filing a Motion for Admission in another Docket.
5. The information contained in the Motion for the Admission Pro Hac Vice of Michael J Bradley, filed contemporaneously with this Affidavit, is true and correct to the best of my knowledge.


Michael J. Bradley

SWORN TO BEFORE ME this
13th day of April 2007


NOTARY PUBLIC





Public Service Commission
Receipt of Payment

Receipt# 6813

Received 4/3/2007 Check# 1009 for \$50 00
Subject Tariff Filing - pd by Peter J Beithon, OTP

Docket # PU-05-131

Prefile balance \$450. Notify

Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56537

Colleen
Thanks for the information—in checking with Jerry Lein publish on 4-2

Thank you
Pat Miller

From: Colleen Park [mailto:colleenp@ndna.com]
Sent: Wednesday, March 21, 2007 2:23 PM
To: Miller, Patricia A.
Subject: RE Notice of Hearing, Case No. PU-05-131

Received.
The notice can publish in all papers next week, except for The Forum which will publish on 4/2 (or they can all publish on 4/2 or 4/3)
Let me know if there is a preference.
Colleen

From: Miller, Patricia A. [mailto:patmiller@nd.gov]
Sent: Wednesday, March 21, 2007 2:00 PM
To: colleenp@ndna.com
Cc: Geiger, Gloria A.
Subject: Notice of Hearing, Case No PU-05-131

Colleen
North Dakota Newspaper Association

Colleen

Please have the attached Notice of Hearing published as a legal publication in the next issue of the following newspapers
Do not publish in the classifieds

Bismarck Tribune
Devils Lake Journal
Grand Forks Herald
Minot Daily News
The Daily News
The Fargo Forum
The Jamestown Sun
Valley City Times-Record

Please run it as a "News Item Only" article as well, and send the bill to the Public Service Commission along with a tear sheet for billing purposes

If you have any questions, please call me at 328-4076, or e-mail me

Pat Miller
Public Utilities Division
Public Service Commission
600 E Boulevard Ave, Dept 408
Bismarck ND 58505-0480
701-328-4076

Miller, Patricia A.

From: Miller, Patricia A
Sent: Wednesday, March 21, 2007 2:00 PM
To: 'colleenp@ndna.com'
Cc: Geiger, Gloria A
Subject: Notice of Hearing, Case No. PU-05-131
Attachments: Notice.doc

Colleen
North Dakota Newspaper Association

Colleen

Please have the attached Notice of Hearing published as a legal publication in the next issue of the following newspapers. Do not publish in the classifieds.

Bismarck Tribune
Devils Lake Journal
Grand Forks Herald
Minot Daily News
The Daily News
The Fargo Forum
The Jamestown Sun
Valley City Times-Record

Please run it as a "News Item Only" article as well, and send the bill to the Public Service Commission along with a tear sheet for billing purposes.

If you have any questions, please call me at 328-4076, or e-mail me.

Pat Miller
Public Utilities Division
Public Service Commission
600 E Boulevard Ave, Dept 408
Bismarck ND 58505-0480
701-328-4076

Miller, Patricia A.

From: System Administrator
To: mbring@minnkota.com
Sent: Wednesday, March 21, 2007 1:45 PM
Subject: Undeliverable: Notice of Hearing, Case No. PU-05-131

Your message did not reach some or all of the intended recipients

Subject: Notice of Hearing, Case No. PU-05-131
Sent: 3/21/2007 1:47 PM

The following recipient(s) could not be reached

mbring@minnkota.com on 3/21/2007 1:45 PM
There was a SMTP communication problem with the recipient's email server. Please contact your system administrator
<itdemailfe1@nd.gov #550>

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff

Case No. PU-05-131

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Patricia Miller deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **21st day of March, 2007**, she deposited in the United States Mail, Bismarck, North Dakota, **7** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Hearing

The envelopes were addressed as follows:

Bernadeen Brutlag
Manager - Regulatory Services
Otter Tail Corporation
215 S Cascade St.
Fergus Falls MN 56538-0496
Cert. No. 7005 3110 0003 6265 0159

Donald R. Ball
Vice President – Regulatory Affairs
Montana-Dakota Utilities Co.
400 N. 4th St.
Bismarck ND 58501
Cert. No. 7006 0100 0003 7161 2880

Dave Sederquist
Senior Consultant – Regulatory & Finance
Xcel Energy
P O Box 2747
Fargo ND 58208-2747
Cert. No. 7006 0100 0003 7161 2897

Thomas D. Kelsch
Counsel for North Dakota OTP Large
Industrial Energy Group
P. O. Box 1266
Mandan ND 58554-7266
Cert. No. 7006 0100 0003 7161 2903

Bruce Gerhardson
Associate General Counsel
Otter Tail Corporation
215 S Cascade St.
Fergus Falls MN 56538-0496
Cert. No. 7006 0100 0003 7161 2910

Daniel S. Kuntz
Associate General Counsel
Montana-Dakota Utilities Co.
P. O. Box 5650
1200 West Century Avenue
Bismarck N 58506-5650
Cert. No. 7006 0100 0003 7161 2927

Megan Hertzler
Assistant General Counsel
414 Nicollet Mall, 5th Flr.
Minneapolis MN 55401
Cert. No. 7006 0100 0003 7161 2934

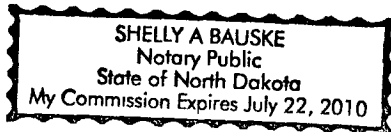
Each address shown is the respective addressee's last reasonably ascertainable post office address.

Patricia Medina

Subscribed and sworn to before me
this **21st day of March, 2007**.

Shelly A Bauske
Notary Public

SEAL



STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff

Case No. PU-05-131

AFFIDAVIT OF SERVICE BY ORDINARY MAIL AND EMAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Patricia Miller deposes and says that:

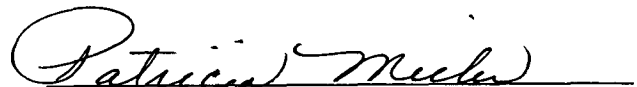
she is over the age of 18 years and not a party to this action and, on the **21st day of March, 2007**, she deposited in the United States Mail, Bismarck, North Dakota, **23** envelopes by regular mail, with postage fully prepaid, securely sealed, each containing a photocopy of the same.

Notice of Hearing

The envelopes were addressed as follows:

See the attached list.

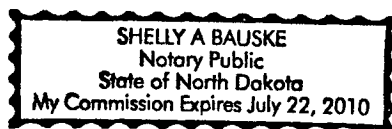
Each address shown is the respective addressee's last reasonably ascertainable post office address.



Subscribed and sworn to before me
this **21st day of March, 2007**.


Notary Public

SEAL



Steven Tomac
2498 59th St
St Anthony ND 58566-9640

Patricia Estes
Daily News
PO Box 760
Wahpeton ND 58074-0760

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

KHRT AM
PO Box 1210
Minot ND 58702-1210

KNOX-AM & KRRK-FM
PO Box 13638
Grand Forks ND 58208-3638

KTHI-TV
Fargo ND 58107-1878

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

James Irwin
Natural Gas Week
1411 K Street Suite 602
Washington DC 20005-3404

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

William Jackson
Dakota Justice
38 8th Ave W
Dickinson ND 58601

Mark Frederiksen
Economic Insights
416 Center St #365
Washington Grove MD 20880

News Director
KHND AM Radio
PO Box 6
Harvey ND 58341-0006

Myer Shark
Knollwood Place Apts #221
3630 Phillips Pkwy
St Louis Park MN 55426

KOVC AM and KQDJ FM Radio
136 North Central Avenue P O Box 994
Valley City ND 58072-0994

Bruce Imsdahl
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Dennis Lavalley
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Andrew Anderson
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

Public Utilities Reports Inc
Law Dept 8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Dave Johnson
Valley City Public Works
254 2nd Ave NE
Valley City ND 58072

nanso@cableone.net
James M Nessa

3500 8th Ave S #201
Moorhead MN 56560

shandy@kwh.com
Scott Handy
Cass County Electric Coop
4100 32nd Ave SW
Fargo ND 58104

arsmith@invisimax.com

KAOC, KAUI, KYTZ FM and KXPO AM radio
856 W 12 St
Grafton ND 58237

gary.rogers@kbmwam.com

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

kdakam@daktel.com
News Director
KDAK AM
Box 50
Carrington ND 58421-0050

dthompson@prairiepublic.org
News Director
KDSU KCND KPRJ KMPR KPPR KDPR
1814 North 15th Street
Bismarck ND 58501

dickvoight@clearchannel.com

KFGO
Box 2966
Fargo ND 58102-2966

sales@kmavradio.com

KMAV AM/FM RADIO
PO Box 216
Mayville ND 58257-0216

knck1080@utma.com

KNCK-AM
HCR 5 Box 9
Langdon ND 58249

bigdog@daktel.com

KXGT and KYNU FM, KQDJ AM Radio
203 1st Ave S PO Box 1170
Jamestown ND 58402-1170

bschmidt@kwh.com
Brad Schmidt
Cass County Electric Coop
4100 32nd Ave SW
Fargo ND 58104

bnicholls@dadco.com
Bryan Nicholls
D A Davidson & Co

bdenver@btinet.net
News Director
KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

rickstensby@clearchannel.com

KCJB, KRRZ AM and KMXA, KYYZ, KIZZ
PO Box 10
Minot ND 58702-0010

kzzynews@stellarnet.com
News Director
KDLR AM and KDVL, KQZZ FM Radio
Box 190
Devils Lake ND 58301-0190

richard.mattern@ndsu.nodak.edu
Rich Mattern
KDSU-FM Radio
PO Box 5347
Fargo ND 58105-5347

patmclean@clearchannel.com

KKXL AM and KKXL, KQHT, KJKJ, KSNR
PO Box 13598
Grand Forks ND 58208-3598

mlyman@kmot.com

KMOT TV
Box 1120
Minot ND 58702-1120

news@ksjbam.com
News Director
KSJB AM and KSJZ FM Radio
PO Box 5180
Jamestown ND 58402-5180

mail@kvlytv11.com

KXJB-TV 4
4302 13th Ave S
Fargo ND 58103-3313

treiten@kxnet.com

KXMB TV
Box 1617
Bismarck ND 58502-1617

kzzj@kzzj.com

KZZJ-AM
230 Highway 2 SE
Rugby ND 58368-2446

craig_scott@bobcat.com

Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

karen.collins@mdu.com; tamie.aberle@mdu.com

Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

hfuglest@ndarec.com

Harlan Fugelsten
ND Assn Rural Electric Coops
PO Box 727
Mandan ND 58554-0727

kchristianson@state.nd.us

Kim Christianson
ND Department of Commerce

Bismarck ND

dross@otpc.com

David Ross
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

bbrutlag@otpc.com

Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

sschultz@otpc.com

Steve Schultz
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

llaugtug@otpc.com

Loren Laugtug
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

jolson@kxmcnews.com

KXMC TV
Box 1686
Minot ND 58701-1686

harking@oz.net

Harriet King
McGraw-Hill/Platts

mbring@minnkota.com

Mark Bring
Minnkota Power Cooperative, Inc
Box 13200
Grand Forks ND 58208-3200

don.ball@mdu.com

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

jiszler@state.nd.us

Jocie Iszler
ND Corn Utilization Council
1325 23rd ST S
Fargo ND 58103

dweiby@otpc.com

Dan Weiby
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

rdenault@otpc.com

Russ Denault
Otter Tail Corporation
410 College Ave
Crookston MN 56716

dellefson@otpc.com

Dennis Ellefson
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

rmontonye@otpc.com

Ron Montoyne
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

pbeithon@otpc.com

Pete Beithon
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

tgreene@otpc.com
Tim Greene
Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56538-0496

lakeleader@aol.com
John M Wylie II
Platts Electric Power Publications
109 S Maple St
Oologah OK 74053-1175

alaamodt@wday.com

WDAY AM-FM & TV
PO Box 2466
Fargo ND 58108-2466

dave.sederquist@xcelenergy.com
Dave Sederquist
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

gcoyne@otpc.com
Geri Coyne
Otter Tail Corporation
PO Box 410
Oakes ND 58474-0410

mdickerson@nd.gov
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

news@wdaz.com

WDAZ-TV
PO Box 12639
Grand Forks ND 58208-2639

APPROVED

DATE: 3-21-07
SAB

MOTION

March 21, 2007

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

I move the Commission issue a Notice of Hearing in the application of Otter Tail Corporation d/b/a Otter Tail Power Company for fuel cost adjustment recovery of Midwest ISO Day-2 energy market costs, Case Nos. PU-05-131.

JRL

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

**NOTICE OF HEARING
March 21, 2007**

On March 1, 2005, in Case No. PU-05-131, Otter Tail Corporation, d/b/a Otter Tail Power Company (Otter Tail) filed revisions to its Fuel Cost Adjustment tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO Day 2 regional wholesale electric energy market. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing new accounting procedures for interim fuel clause recovery of the net costs of energy purchased through the new market subject to refund with interest in the event the Commission ultimately orders a different or modified accounting treatment that results in lower charges. On January 24, 2007 the Commission granted intervention to the ND OTP Large Industrial Energy Group.

A **public hearing** on this matter will be held beginning **May 22, 2007 at 9:00 a.m. CDT** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. You can listen to a broadcast of the hearing on the Commission's website at <http://www.psc.state.nd.us/psc/media/comm-live.html>. The issues to be considered are:

1. Whether the interim accounting treatment authorized for recovery of Day 2 market costs is appropriate and should be continued or whether a different or modified accounting treatment should be required.
2. Whether a percentage of wholesale revenues derived from off system energy sales should be shared with retail customers
3. Whether any amounts already collected should be refunded with interest

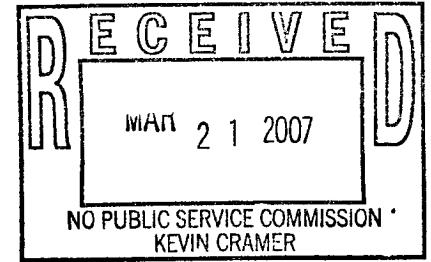
For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify Ilona Jeffcoat-Sacco, Executive Secretary, at least 24 hours in advance.

PUBLIC SERVICE COMMISSION



Tony Clark **Susan E. Wefald** **Kevin Cramer**
Commissioner **President** **Commissioner**

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



VIA Electronic Mail and Overnight Delivery

March 21, 2007



Ms Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505

SUBJECT. Correction of Typographical Error in Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY's (Otter Tail) Cost of Energy Adjustment Clause Tariff (Sheet 98, Rate Designation M-60N)

Dear Ms Jeffcoat-Sacco

Otter Tail Corporation d/b/a Otter Tail Power Company has discovered a typographical error in its Cost of Energy Adjustment Clause Tariff (Sheet 98, Rate Designation M-60N) The second paragraph in the tariff sheet approved on July 13, 2005 reads

"Energy costs from actual months 1, 2, 3, 4 and 5 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, 4 and 5 equals the cost of energy adjustment for month 6 "

The second paragraph should read

"Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, and 4 equals the cost of energy adjustment for month 6 "

The change eliminates "5" from the description of the months used for the cost of energy adjustment rate calculation This is a typographical error and has not governed Otter Tail's calculation of its cost of energy rate Otter Tail has been calculating the cost of energy rate in compliance with North Dakota Administrative Rule 69-09-02-39.

We respectfully request the North Dakota Public Service Commission approve this request for correction of the typographical error in Otter Tail's Cost of Energy Adjustment Clause Tariff (Sheet 98, Rate Designation M-60N) at its earliest convenience

23 PU-05-131

Pages 4

Correction of Typo Error in OTP's Cost of Energy Adjustment Clause Tariff by Otter Tail Corporation

03/21/2007 Comm, Legal Illona Annette Mike ALJ

Page 2
Otter Tail Power
March 21, 2007

Enclosed is an original and seven copies of Otter Tail Power Company's proposed Tariff sheet 98 (volume1), rate designation M-60N, page 1 of 1 (both normal and red-line versions) A fifty dollar filing fee payable to the North Dakota Public Service Commission is also enclosed An electronic copy of the filing is being sent via email to you at js@nd.gov and to Jerry Lein at jlein@nd.gov and to ndpsc@nd.gov

If you have any questions regarding this filing, please contact me at (218) 739-8607 or pbeithon@otpc.com

Yours very truly,

A handwritten signature in black ink, appearing to read 'Pete Beithon', with a long horizontal line extending to the right.

Pete Beithon
Manager, Regulatory Economics
Enclosure

COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

Energy costs from actual months 1, 2, 3, 4 and ~~4~~ 5 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, 4 and ~~4~~ 5 equals the cost of energy adjustment for month 6.

The applicable adjustment will be applied effective on any billing dated on or after the first day of each calendar month. The average cost of energy shall be determined as follows:

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants. Energy from the Company's hydro generating plants shall be included at zero cost.
2. The energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges. This includes but is not limited to net costs 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.
3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. Less the fuel related costs recovered through intersystem sales.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
ND

Approved: July 13, 2005, 2007
Case No. PU-05-131

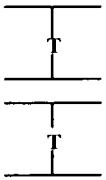
RATES EFFECTIVE with bills rendered
on and after August 1, 2005, in

APPROVED: Bernadeen Brutlag
Manager, Regulatory Services

COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, and 4 equals the cost of energy adjustment for month 6.



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1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants. Energy from the Company's hydro generating plants shall be included at zero cost.
2. The energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges. This includes but is not limited to net costs 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
3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above
4. Less the fuel related costs recovered through intersystem sales.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Approved: _____, 2007
Case No PU-05-131

RATES EFFECTIVE with bills rendered
on and after _____, 2007, in ND

APPROVED: Bernadeen Brutlag
Manager, Regulatory Services



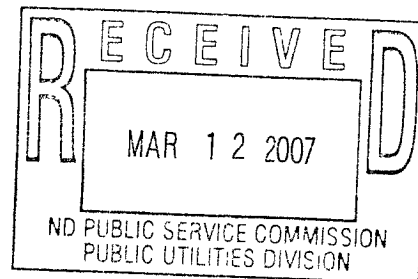
Fargo office	Fergus Falls office
4334 18th Avenue S W	215 S Cascade Street
Suite 200, PO Box 9156	PO Box 496
Fargo, ND	Fergus Falls, MN
581.06.9156	565.38.0496
Fax 701-232-4108	Fax 218-998-3165

1-866-410-8780 • www.ottertail.com

March 8, 2007

Reply to Fergus Falls office
Direct: 218-998-7108

Mr Thomas D Kelsch
Kelsch Kelsch Ruff & Kranda
103 Collins Avenue
P. O Box 1266
Mandan, ND 58554-7266



Mr. Jerry Lein
North Dakota Public Service Commission
600 E Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

**Re: MISO Day 2 Costs - Cost of Fuel Adjustment Clause Tariff
NDPSC Case No. PU-05-131**

Dear Mr Kelsch and Mr. Lein

This letter confirms the agreements we reached in our scheduling conference in the above-referenced matter, which was held on February 28, 2007.

Schedule

The procedural schedule will be as follows:

April 20, 2007 – Due date for prefiled written direct testimony from Intervenors

May 14, 2007 – Due date for prefiled written rebuttal testimony from Otter Tail.

May 22, 2007 – Hearing at NDPSC.

Discovery

We will respond to your February 21, 2007 discovery requests on or before March 20, 2007. We will also, before that time, as soon as practicable, provide you with any questions we may have on your interrogatories so that we may provide as full an answer as possible. Also, Otter Tail will provide, as soon as practicable, comments regarding interrogatories for which Otter Tail would not have the information requested (such as if the data would be in the possession of MISO rather than in the possession of Otter Tail, etc.).

It is possible that Otter Tail may have interrogatories or other discovery that it wishes to conduct after seeing the prefiled direct testimony from the Intervenors. You have agreed on behalf of the Intervenors to respond as quickly as possible to any such discovery requests in order that Otter Tail

Mr. Kelsch
Mr. Lein
March 8, 2007
Page 2

might have the benefit of those responses several days in advance of its May 14, 2007 filing of prefiled rebuttal testimony.

Finally, while we did not discuss this during the telephone conference, it is my belief that we should immediately work toward an acceptable Confidentiality Agreement for any trade secret or otherwise confidential information that may be filed in this matter. Given the sensitive nature of some of the data, I believe it is quite likely we will need to file some information as confidential, trade secret information.

Narrowing the Issues

The Intervenor, upon receipt of Otter Tail's discovery responses, will endeavor to narrow the issues in dispute in this matter so that the scope of the testimony, rebuttal and other preparations can similarly be narrowed. Once the issues are narrowed, Intervenor will communicate the remaining issues to Mr. Lein so that he may prepare and publish an appropriate hearing notice for this matter.

May 22, 2007 Hearing

The Intervenor will present live testimony from their witnesses first, and Applicants will provide live testimony from their witnesses second. Live testimony will consist of a summary of the prefiled written testimony and surrebutal will be presented live, but will be limited to a response to the most recently tendered testimony (for Intervenor, surrebutal will be limited to a response to Otter Tail's prefiled written rebuttal, and for Otter Tail, surrebutal will be limited to a response to Intervenor's live surrebutal testimony). Limiting surrebutal in this fashion is intended to alleviate any concern that any party may raise new issues on the stand that were not raised in previous rounds of testimony. It is our expectation that the Administrative Law Judge will rule on beyond-the-scope objections consistent with this agreement.

It is our understanding that you, Jerry, will file this letter and that either it will have the same power and effect as a formal scheduling order, or you will obtain a formal scheduling order consistent with these terms.

Sincerely,



Bruce Gerhardson
Associate General Counsel
BG/dm

c. Pete Berthon
Bernadeen Brutlag



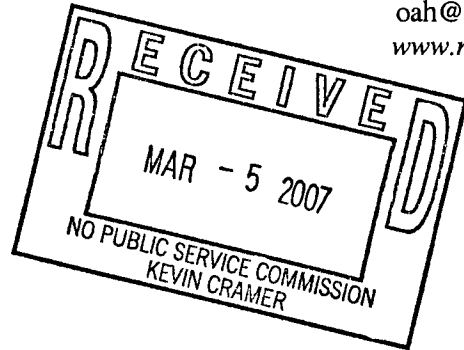
OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state.nd.us
www.nd.gov/oah

March 2, 2007



Mr. William W Binek
Chief Counsel
Public Service Commission
600 East Boulevard Avenue
Bismarck, ND 58505

Dear Mr. Binek.

Thank you for your February 27, 2007, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Ottertail Corporation. I hereby designate myself, Allen C. Hoberg, to be assigned as an administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will be making the final administrative decision in regard to this matter (*i.e.* commission) must be in attendance at the hearing.

Please send all additional relevant documents (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Bismarck, North Dakota 58501-1882. I understand the hearing is scheduled for May 22, 2007, beginning at 9:00 a.m., in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. Because the administrative law judge is requested to conduct the hearing only, the agency must give proper notice of the hearing.

Your request has been assigned OAH File No. 20070083. Please include this number on all future documents and correspondence filed for this matter with the Office of Administrative Hearings.

Sincerely,

Allen C. Hoberg
Director

ACH/lmw

cc. Mr. Bruce Gerhardson
Ottertail Corporation
Mr. Thomas D. Kelsch
Counsel for ND OTP Large Industrial Energy Group

21 PU-05-131

Pages 1

ALJ Assigned (Hoberg)

by Office of Administrative Hearings
03/05/2007 CC Comm Legal Illona, Annette, Mike



REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION
NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS
 SFN 17819 (Rev 03-2001)

Name of Agency, Board, or Commission
 Public Service Commission

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the hearing in Case No PU-05-131, Otter Tail Corporation, Cost of Energy Adjustment Clause Tariff
 Hearing is set for May 22, 2007 at 9 00 a.m in the Commission's Hearing Room 12th Floor State Capitol, Bismarck

(e.g., application of [name], appeal of [name], petition of [name]) Authority for the administrative action is found in Title 49 _____ (North Dakota Century Code and/or North Dakota Administrative Code)

Please attach related documents and correspondence

The administrative action is more fully described as follows

It requests designation of an administrative law judge (please check one)

- To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.
- To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).
- To conduct the hearing, issue findings of fact, conclusions of law, and a final order.

PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact (Attach separate list if necessary)

AGENCY Public Service Commission	Address 600 E Blvd Ave, Dept 408 Bismarck, ND 58505	Telephone Number 701-328-2400
Representation William W Binek, Chief Counsel	Address Same as above	Telephone Number 701-328-4088
PARTY Ottetail Corporation	Address 215 S Cascade Street, Fergus Falls, MN 56538	Telephone Number 218-739-8218
Representation Bruce Gerhardson	Address 215 S Cascade Street, Fergus Falls, MN 56538	Telephone Number 218-739-8218
PARTY ND OTP Large Industrial Energy Group	Address	Telephone Number
Representation Thomas D Kelsch, Counsel	Address PO Box 1266, Mandan, ND 58554-7266	Telephone Number 701-663-9818

Additional Comments
 Hearing will be tape recorded and a court reporter may be present

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested. Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of the notice.)

Typed or Printed Name and Title of Requesting Person William W Binek, Hearing Administrator	Date 02/27/07
Signature of Requesting Person 	Telephone Number 701-328-4088



Public Service Commission

State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www.psc.state.nd.us
e-mail ndpsc@nd.gov
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 24, 2007

Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496

Dear Ms. Brutlag:

On January 24, 2007, the Commission granted intervention to the North Dakota OTP Large Industrial Energy Group, Case No. PU-05-131.

Please note also that under N.D.C.C. 28-32-33, permission to conduct discovery is only required before obtaining discovery from an administrative agency.

Sincerely,

Patricia Miller
Public Utilities Division

pam

Enclosure

cc: Thomas D Kelsch,
Counsel for North Dakota OTP Large Industrial Energy Group

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Corporation
Cost of Energy Adjustment Clause
Tariff

Case No. PU-05-131

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Patricia Miller deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **24th day of January, 2007**, she deposited in the United States Mail, Bismarck, North Dakota, **two** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of.

Order Granting Intervention

The envelopes were addressed as follows:

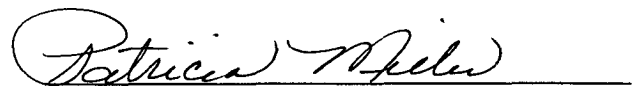
Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496

Cert. No. 7006 0100 0003 7161 2804

Thomas D Kelsch
Counsel for North Dakota OTP Large
Industrial Energy Group
PO Box 1266
Mandan ND 58554-7266

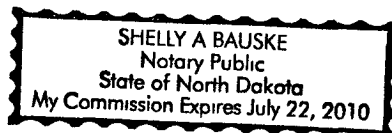
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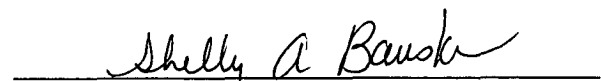
Each address shown is the respective addressee's last reasonably ascertainable post office address.



Subscribed and sworn to before me
this **24th day of January, 2007**.

SEAL




Notary Public

18 PU-05-131

Pages 1

Affidavit of service by certified mail

by Public Service Commission

01/24/2007 CC Comm Legal Ilona, Annette, Mike

APPROVED

DATE: 1-24-07
SAB

MOTION

January 24, 2007

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

I move the Commission adopt the Order granting intervention to the ND OTP Large Industrial Energy Group in Case No. PU-05-131, Otter Tail Corporation's Cost of Fuel Adjustment Clause tariff

JRL

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

ORDER GRANTING INTERVENTION

January 24, 2007

On January 12, 2007 ND OTP Large Industrial Energy Group filed a Petition to Intervene in this proceeding. The petition stated that the group is made up of several of Otter Tail Corporation's d/b/a Otter Tail Power Company (Otter Tail) largest industrial consumers in North Dakota including Northern Sun/ADM, Cargill Incorporated, Goodrich, Bobcat, Imation and Cavendish Farms. The Large Industrial Energy Group states in its petition that it has an interest in the proper rate making treatment and fuel clause flow through of Midwest ISO day-2 market costs. The Group requests additional time estimated at no more than 90 days to conduct discovery followed by a hearing after discovery is completed.

On January 17, 2007, Otter Tail filed its Objection to North Dakota OTP Large Industrial Energy Group's Petition to Intervene. Otter Tail requests the Commission deny the petition or condition and limit the intervention so as not to unduly delay the proceedings or broaden the issues.

The Commission finds that the ND OTP Large Industrial Energy Group has an interest in these matters that is not adequately represented by other parties and its participation will not unduly broaden the issues or delay the proceedings.

Order

The Commission orders:

1. The ND OTP Large Industrial Energy Group's Petition to Intervene is granted.
2. Admission as an intervenor shall not be construed as recognition by the Commission that an intervenor might be aggrieved by an order of the Commission in this case.

PUBLIC SERVICE COMMISSION


Tony Clark
Commissioner


Susan E. Wefald
President


Kevin Cramer
Commissioner



January 17, 2007



Fargo office: 4334 18th Avenue S W
Suite 200, PO Box 9156
Fargo, ND
58106-9156
Fax 701-232-4108

Fergus Falls office: 215 S Cascade Street
PO Box 496
Fergus Falls, MN
56538-0496
Fax 218-998-3165

1-866-410-8780 • www.ottertail.com

Reply to Fergus Falls office
Direct: 218-998-7108

Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 E. Boulevard Avenue
Bismarck, ND 58505-0480

Re: Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
Case No. PU-05-131

Dear Ms. Jeffcoat-Sacco:

Enclosed for filing, please find an original and seven copies of Otter Tail's Objection to the North Dakota OTP Large Industrial Energy Group's petition to intervene in the above matter.

If you have any questions, please feel free to contact me at any time.

Sincerely,

Bruce Gerhardson
Associate General Counsel
BG/dm

Enclosures

c: Thomas D. Kelsch
Chuck MacFarlane
Bernadeen Brutlag
Tom Brause
Mark Helland

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

Otter Tail Corporation)
Cost of Fuel Adjustment Clause)
Tariff)

Case No. PU-05-131

**OBJECTION TO NORTH DAKOTA OTP LARGE INDUSTRIAL ENERGY GROUP'S
PETITION TO INTERVENE**

On or about January 12, 2007, the North Dakota OTP Large Industrial Energy Group ("Large Industrial Energy Group") filed a petition to intervene in the above-referenced case. Otter Tail Corporation, d/b/a Otter Tail Power Company ("Otter Tail") objects to that petition for the following reasons:

1. Granting the Large Industrial Energy Group's petition would unduly delay these proceedings. Section 69-02-02-05 of the North Dakota Administrative Code provides for intervention by a party only when intervention "would not unduly broaden the issues or delay the proceeding." (Emphasis added.) This proceeding is already almost two years old. Otter Tail filed its fuel clause adjustment ("FCA") revisions on March 1, 2005. The Commission held an informal hearing on March 23, 2005, and issued an interim order on April 6, 2005. The Large Industrial Energy Group proposes that it should be allowed to intervene for the purpose of conducting discovery that would take approximately 90 days, and then to make filings based on that discovery as well as file expert testimony in this matter. They have not explained in their petition why they waited almost two years to petition for intervention. Granting their request would most certainly unduly delay the proceedings, which have already been pending for a very long time. Indeed, it appears that the Large Industrial Energy Group's intentions are to convert this matter into a full blown contested case proceeding despite the fact that their request is being made almost two years after the initial filing.

2. To the extent that the Large Industrial Energy Group might argue that they have any procedural or substantive right to intervention, Section 69-02-01-10 of the North Dakota

Administrative Code states that “this Article shall be liberally construed to secure the just, speedy, and inexpensive determination of the issues presented.” (Emphasis added). It is our concern, as identified above, that granting of the Large Industrial Energy Group’s petition would substantially impede the Commission’s final determination in this matter.

3. To the extent the Large Industrial Energy Group has articulated in its petition its interests in this proceeding, those interests will be better protected in other proceedings, such as Otter Tail’s next general rate case. As their petition indicates, the most substantial issue for them is Otter Tail’s wholesale power revenues and their desire that Otter Tail share a percentage of those revenues with customers. Adding such issues to this case would “unduly broaden” this proceeding in contradiction to Section 69-02-02-05 of the North Dakota Administrative Code. Additionally, in support of their position, the Large Industrial Energy Group cites an example in Minnesota which they say requires energy companies to share MISO wholesale power revenue. It should be noted that in Minnesota, Otter Tail has not been required to share wholesale power margins as their petition suggests. Rather, Otter Tail has agreed to address whether or not such a sharing should occur in its next general rate case in Minnesota. Likewise, the Staff report in this case includes a recommendation that an investigation into the sharing of wholesale margins should be made part of Otter Tail’s next general rate case. Therefore, it is Otter Tail’s position that the interests articulated by the Large Industrial Energy Group should be addressed in a future general rate case proceeding, not this one.

4. It should also be noted that the Staff recommendations in this case are not materially different from either 1) the Commission’s April 6, 2005 Interim Order in this matter, or 2) the result of the Minnesota proceedings which were recently concluded on similar FCA recovery of MISO Day 2 costs (the only exception is that Staff in this case recommends FCA recovery of Schedules 16 and 17 rather than deferral of those charges, as is the case in the Minnesota Order). The Large Industrial Energy Group’s petition does not express how its intervention or the lengthy procedural latitude it seeks would contribute to these proceedings and, therefore, its petition should be denied.

5. In the event the Commission decides to grant the Large Industrial Energy Group's petition to intervene, Otter Tail requests that the Commission impose appropriate conditions and limitations on their intervention. Section 69-02-02-05 authorizes the Commission to impose such conditions and limitations in order to promote the interest of justice. Therefore, if the Large Industrial Energy Group is allowed to intervene, their request for delays should be denied. Rather, it is Otter Tail's position that the Commission should act with all due speed toward entry of a final Order on this matter. As previously indicated, Otter Tail has been collecting MISO Day 2 costs through its fuel clause adjustment pursuant to an Interim Order for almost two years. Collecting revenues on this basis creates a great deal of uncertainty and, thereby, substantially prejudices Otter Tail. The interests of justice are best served by avoiding such uncertainty. Therefore, if the Large Industrial Energy Group is allowed to intervene, appropriate limitations and conditions should be made in order that these proceedings are no longer delayed.

For the foregoing reasons, Otter Tail objects to the Large Industrial Energy Group's petition and requests that the Commission deny their petition or, in the alternative, condition and limit their intervention as provided herein.

Date: January 17, 2007

OTTER TAIL CORPORATION

By: 

Bruce Gerhardson
Associate General Counsel

Kelsch Kelsch Ruff & Kranda

C F Kelsch
1890-1987

Attorneys at Law
Mandan, North Dakota

William C Kelsch
Retired

THOMAS F KELSCH
ARLEN M RUFF, P C
THOMAS D KELSCH, P C
TODD D KRANDA, P C *
WILLIAM J DELMORE
DANIEL NAGLE

*Also Licensed in Minnesota

 MERITAS LAW FIRMS WORLDWIDE

103 Collins Avenue
P O Box 1266
Mandan, ND 58554-7266
Phone (701) 663-9818
1-888-663-9818
Fax (701) 663-9810
Website www.kelschlaw.com

January 12, 2007

ILLONA JEFFCOAT-SACCO
ND PUBLIC SERVICE COMMISSION
600 E BOULEVARD AVE
BISMARCK ND 58505-0480

RE: Case No. PU-05-131
NDPSC
Otter Tail Corporation
Cost of Fuel Adjustment Clause Tariff
Petition to Intervene of North Dakota OTP Large Industrial Energy Group
Our File No. 12039



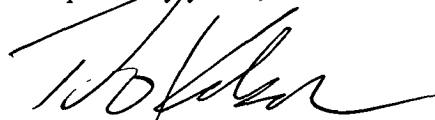
Dear Ms. Jeffcoat-Sacco:

I am enclosing an original and 7 copies of the Petition to Intervene in the above case no. PU-05-131 on behalf of ND OTP Large Industrial Energy Group and an Affidavit of Service by Mail and Facsimile.

I am also enclosed an extra copy of the Petition to Intervene. Please file stamp this copy and return to my office.

If you have any questions, please give me a call.

Respectfully yours,



Thomas D. Kelsch

TDK:dr

Enclosures

cc: Eric Hoegger, Cargill, Incorporated
Steve Otto, Imation
Chuck McFarlane, Otter Tail Corporation
Bruce Gerhardson, Otter Tail Corporation



14 PU-05-131

Pages 5

Petition to Intervene

by Kelsch Kelsch Ruff & Kranda by ND Large Industrial E
01/12/2007 CC Comm Legal Illona Annette Mike

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE)
COMMISSION OTTER TAIL CORPORATION) Docket No. PU-05-131
COST OF FUEL ADJUSTMENT CLAUSE)
TARIFF)

**PETITION TO INTERVENE OF NORTH DAKOTA OTP LARGE INDUSTRIAL
ENERGY GROUP**

ND OTP Large Industrial Energy Group (Large Industrial Energy Group), pursuant to Section 69-02-02-05 of the North Dakota Administrative Code Title 69, hereby petitions to intervene in the above-captioned proceeding. In support of its petition, Large Industrial Energy Group respectfully shows the following:

1

Names, titles and mailing addresses of the persons who should be served with communications concerning this motion are:

Thomas D. Kelsch
Counsel for ND OTP Large Industrial Energy Group
PO Box 1266
Mandan, ND 58554-7266

2.

The Large Industrial Energy Group includes several of Ottetail's largest industrial consumers in North Dakota (Northern Sun/ADM, Cargill Incorporated, Goodrich, Bobcat, Imation, Cavendish Farms). These customers represent a significant economic contribution to the state of North Dakota.

3.

The Large Industrial Energy Group requests additional time to serve formal discovery on Ottetail Power Company (OTP) on the issue of MISO cost recovery, and to file the results of

that discovery as well as expert testimony in this matter. It is estimated that this discovery would take no more than 90 days.

4.

The Large Industrial Energy Group is aware that the NDPSC is considering scheduling this matter for an informal hearing. The Large Industrial Energy Group intends to file written comments in this matter in the near future and requests that the NDPSC schedule a formal hearing in this matter after discovery is completed.

5.

The Large Industrial Energy Group has an interest regarding the proper rate making treatment and fuel clause flow through of the MISO day 2 market costs as reflected in MISO's 32 different cost accounts.

6.

The Large Industrial Energy Group has an interest in the cost makeup of the 32 MISO accounts as well as whether OTP is properly managing its use of the MISO market to reduce retail rates.

7.

The Large Industrial Energy Group seeks full disclosure of OTP's management strategy and "booking" into OTP's account system, as is required in the State of Minnesota.

8.

OTP wholesale power revenues are derived from regulated assets paid for by the ratepayers of North Dakota. It is the Large Industrial Energy Group's position that the North

Dakota Public Service Commission should require OTP to share a percentage of the OTP MISO's wholesale power revenues, derived from these assets, with OTP's customers.

9.

The State of Minnesota as well as other states require energy companies to share MISO wholesale power revenue and the requested action by the Large Industrial Energy Group would be consistent with other state regulations..

10.

The Large Industrial Energy Group has a direct and substantial interest in this proceeding, which may be adversely affected by the Commission's findings and conclusions in this matter. The Large Industrial Energy Group avers that it cannot be adequately represented by existing parties, that it has a right to intervene, and that its intervention is in the public interest.

WHEREFORE, the Large Industrial Energy Group prays that it be permitted to intervene in the above-referenced proceeding.

Respectfully submitted,

North Dakota OTP Large Industrial Energy Group

By  _____

Thomas D. Kelsch
Counsel for North Dakota OTP Large Industrial
Energy Group

PO Box 1266
Mandan, ND 58554-7266

Dated: January 12, 2007

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE)
COMMISSION OTTER TAIL CORPORATION) Docket No. PU-05-131
COST OF FUEL ADJUSTMENT CLAUSE)
TARIFF)

STATE OF NORTH DAKOTA)
) ss. **AFFIDAVIT OF SERVICE**
COUNTY OF MORTON) **BY MAIL & FACSIMILE**

DEBRA K. ROEHRICH being first duly sworn, on oath, deposes and says: That she is a citizen of the United States, over the age of eighteen and not a party to the above-entitled action.

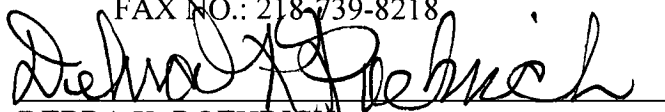
That on the 12th day of January, 2007, this affiant deposited in the United States Post Office at Mandan, North Dakota, and faxed a true and correct copy of the following document(s) in the above-captioned action:

Petition to Intervene of North Dakota OTP Large Industrial Energy Group

That a copy of the above document(s) was securely enclosed in an envelope with postage duly prepaid, and addressed as follows:

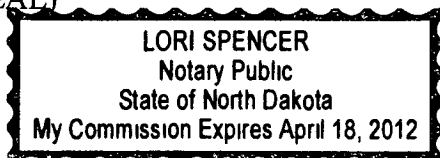
CHUCK MCFARLANE
OTTERTAIL CORPORATION
215 S CASCADE STREET
FERGUS FALLS MN 56538
FAX NO.: 218-739-8218

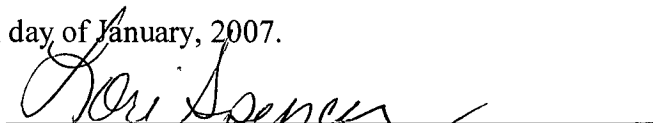
BRUCE GERHARDSON
OTTERTAIL CORPORATION
215 S CASCADE STREET
FERGUS FALLS MN 58538
FAX NO.: 218-739-8218


DEBRA K. ROEHRICH

Subscribed and sworn to before me this 12th day of January, 2007.

(SEAL)




Notary Public, State of North Dakota

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

**STAFF REPORT
December 8, 2006**

Summary:

On April 6, 2005 the Commission issued its Interim Order temporarily authorizing the recovery of costs from the Midwest ISO's new Day-2 energy market through fuel cost adjustments (FCA). The Commission required that each of the 32 Midwest ISO billing line items be recorded as costs of purchased energy in separate sub-accounts under FERC Account 555 Purchased Power.

The Commission found that sufficient Day-2 operational experience and market maturity would be necessary before adopting any permanent accounting treatment. The Commission ordered that FCA recovery of Day-2 costs be authorized on an interim basis and that the recovery of net Day-2 costs be subject to refund plus interest if the Commission ultimately ordered different accounting practices. Compliance tariff changes to standardize language in FCA tariff schedules were approved for all three utilities during July 2005.

Interim recovery of Day-2 market costs began with the June 2005 FCA filings following a two-month FCA accounting lag. At this point the Commission stopped approving monthly FCA filings. Staff began reviewing the new sub-accounts established under Account 555 and the initial market data. Meetings were held with MDU and OTP to begin learning about the 32 MISO market charges and their applications.

Responsibility for staff FCA reviews was reassigned during August 2005 and staff began incorporating MISO market charges into existing FCA spreadsheet models. The August FCA filings provided the first three months of market cost data, ending with the month of June and the beginning of the first summer peaks in the new market. Energy costs had increased, but all three utilities had experienced plant outages such that the data was not yet representative of normal operations.

The August FCA also provided the first Midwest ISO adjustments to Otter Tail's Day-2 market data resulting from metering deficiencies and other difficulties in Otter Tail's multi-utility control area. These and other adjustments/resettlements have continued through the most recent November 2006 FCA filing.

On November 9, 2006, the MN PUC decided it would allow full FCA recovery of MISO market costs except for Schedules 16 and 17 charges, which are to be refunded to customers going back to market start-up and booked into a deferred account as a regulatory asset for an amortization to be determined during each utility's next rate case. Note that NSP had already entered into a rate case settlement agreeing to share certain intersystem sales margins with customers.

Conclusions:

Based on data from initial Day-2 market operations it appears that Otter Tail has not relied heavily on net Day-2 market purchases and the resulting market costs have not been an overly significant portion of Otter Tail's energy costs. It appears that Otter's FCA increases experienced during 2005 resulted primarily from high regional energy prices and Otter Tail's dependence on bilateral energy purchases. Regional prices for on-peak energy appear to correlate with natural gas prices and have since decreased during 2006. Other pricing factors have included a continued tightening of regional generating supplies from growing loads and from additional sales opportunities for regional generators in the new Day-2 market.

These wholesale price increases have benefited Otter Tail and its customers with increased margins from intersystem sales in the initial Day-2 market. Otter Tail reports approximately \$27.2 million in total margins during the period April through December 2005. Of this amount, approximately \$9.6 million were from asset based sales. The remaining approximately \$17.6 million came from non-asset based sales that have not traditionally been reported as regulated earnings. These non-asset based sales have been largely virtual transactions scheduled between the day ahead and real time markets. Prior to market start-up Otter Tail reported \$14.2 million in total intersystem margins and \$6.6 million in asset based margins for the period April-December 2004. Virtual transaction opportunities have tightened during 2006 and for the period January through October 2006 Otter Tail reports non-asset based margins of only \$3.7 million out of \$12.9 million total margins.

MISO administrative and uplift charges have been small compared to energy costs, though uplift charges were higher than expected during 2005. Since then, uplift charges during 2006 have decreased to somewhat more reasonable levels. A major issue has been excessive Revenue Sufficiency Guarantee (RSG) charges used for uplifting revenue shortages arising from reliability needs. These are largely start-up costs for combustion turbines committed to maintain adequate system ramp rates. MISO formed a RSG task force and continued efforts to further reduce RSG are ongoing.

Recommendations:

1. Otter Tail should commit to a schedule for filing a general rate case as soon as practicable.
2. Staff recommends continuing with the current FCA recovery process for Midwest ISO Day-2 market costs at this time. Staff does not recommend refunding and deferring schedule 16 and 17 charges for later rate case recovery because the money would only have to be collected again through increased base rates, and then with a return on the deferral. The total amount of schedule 16 and 17 charges collected from North Dakota customers since the start of the market is approximately \$340,000.
3. In Otter Tail's next general rate case, a sharing of wholesale margins through the fuel clause should be investigated. The Commission has addressed this issue with other utilities in the context of a general rate case.
4. Otter Tail should continue to investigate cost-effective opportunities to displace purchases of energy produced from natural gas with less expensive wind energy.

Discussion:

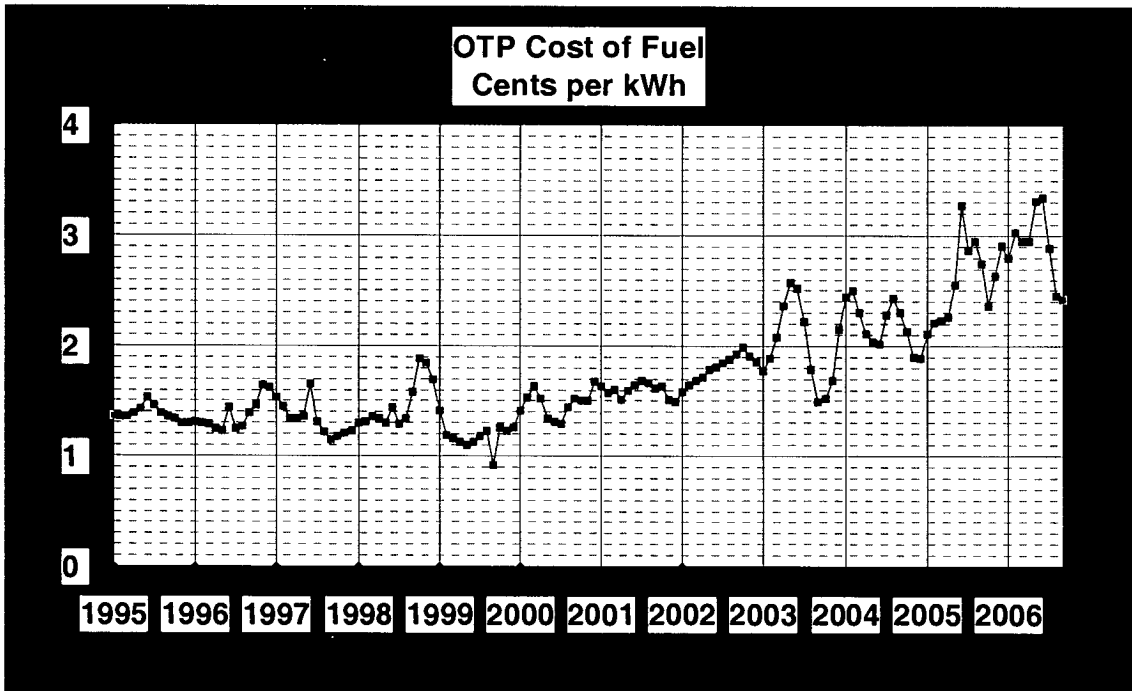


Figure 1

Figure 1 provides Otter Tail's costs of fuel and purchased energy since 1995. This graph is posted on the Commission's web site and shows a trend of increasing costs over the last several years. Figure 2 below focuses on the most recent period from figure 1, including the April 1, 2005 start of the Midwest ISO's Day-2 energy market.

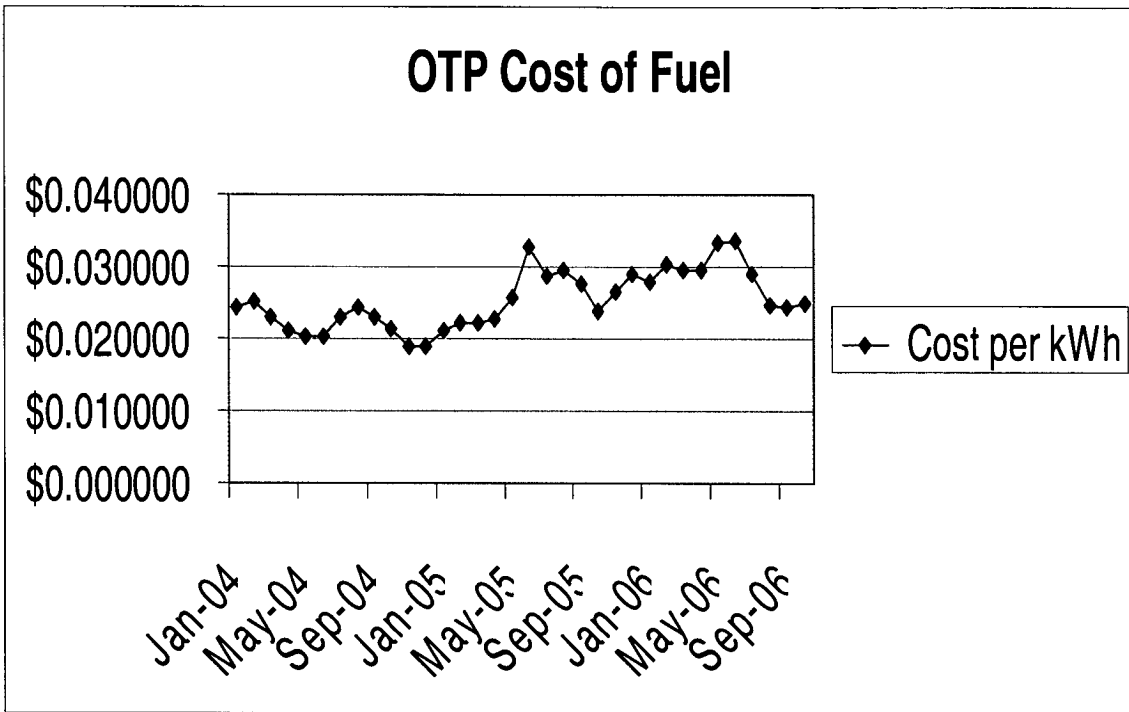


Figure 2

Big Stone Outage:

Figures 1 and 2 indicate a significant price spike appearing coincident with Day-2 market start-up. While the market may share in the blame for the magnitude of the spike, it appears the cause was largely due to an outage of Otter Tail's Big Stone generating station from April 14 thru May 29, 2005. Big Stone, and Coyote are Otter Tail's most economical base-load steam generating stations. Figure 3 indicates the resulting drop in Otter Tail's steam energy production:

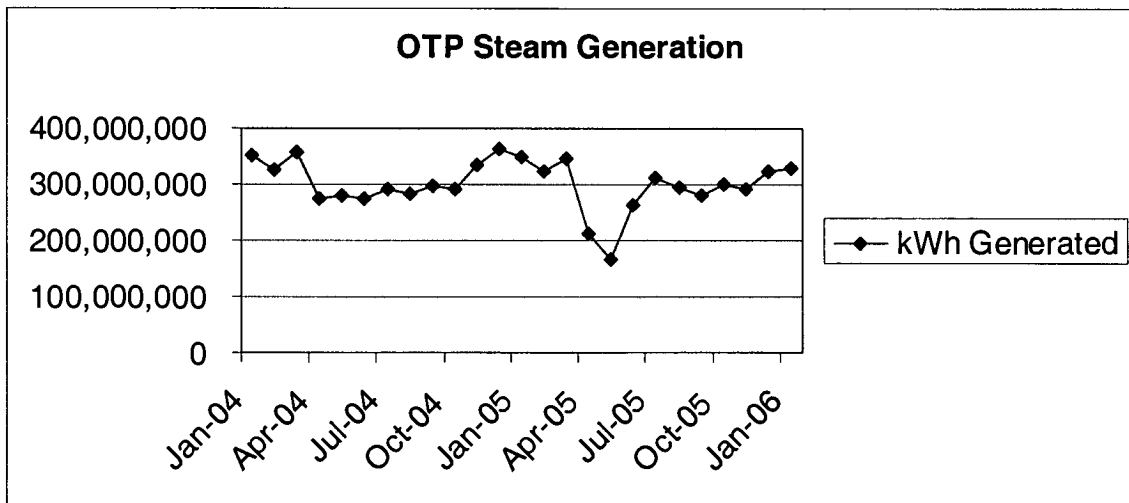


Figure 3

The effect from the Big Stone outage continued into the October FCA cycle as the increased costs of replacement energy passed through the two-month FCA accounting lag and four-month averaging mechanism

OTP Day-2 Energy Costs:

Figures 4 and 5 below indicate Day-2 market energy purchase volumes and costs in relation to Otter Tail's overall energy resource mix.

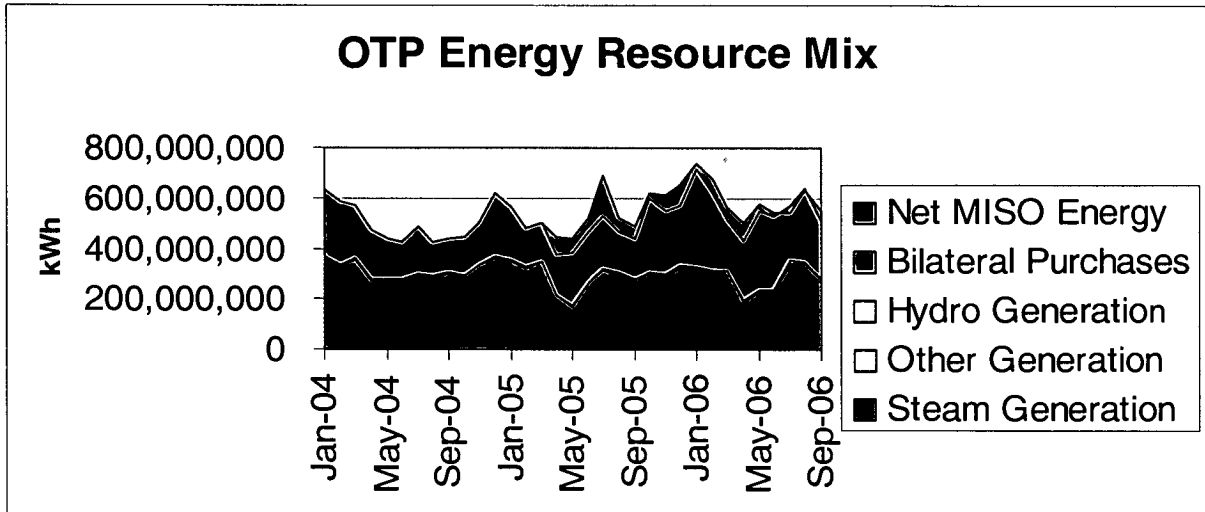


Figure 4

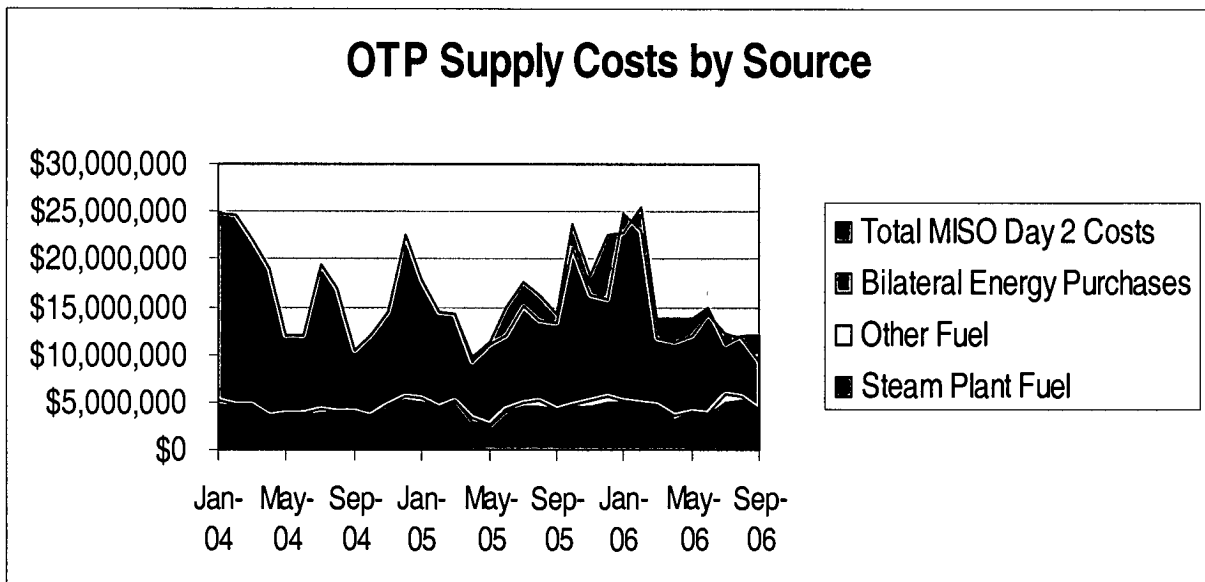


Figure 5

Figure 4 indicates that Otter Tail has not relied heavily on net Day-2 market purchases while Figure 5 shows that the resulting Day-2 costs have not been an overly significant portion of Otter Tail's total energy costs. Figure 5 further

indicates that the most significant portion of Otter Tail's energy costs, both before and after Day-2, have been from bilateral energy purchases.

Bilateral Purchases:

Bilateral contract purchases, sometimes referred to as financial schedules, are scheduled through the Day-2 market subject to LMP congestion and marginal loss charges, but not subject to the market-clearing LMP energy charge. Instead, the energy charge is fixed at a price negotiated between the parties.

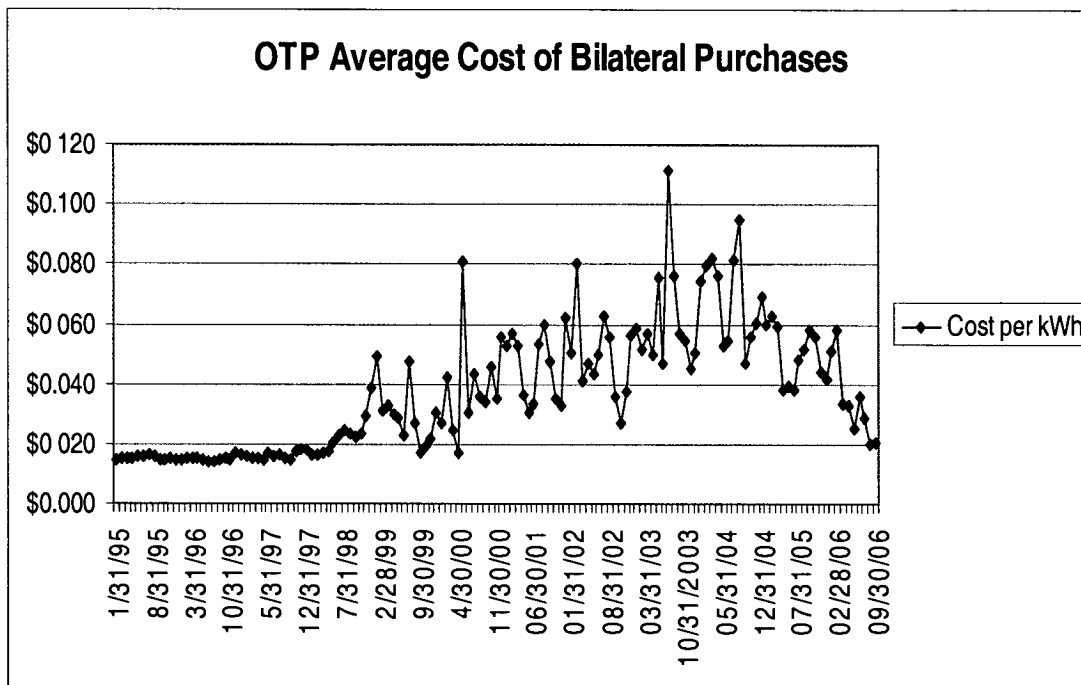


Figure 6

Figure 6 illustrates an increasing trend in Otter Tail's average costs of bilateral energy purchases during recent years leading up to 2006. These bilateral purchases include all bilateral purchases, not just those for serving retail load, but also those credited back in the intersystem sales line of the fuel cost calculations. Comparing the magnitude of bilateral energy purchases in Otter Tail's resource mix shown in figure 6 with the overall cost of energy shown in figures 1 and 2 indicates that Otter Tail's FCA has been driven largely by its dependence on bilateral purchases to meet energy resource needs.

Increases in the costs of regional energy purchases are expected with seasonal peaks and expected in general with the tightening of MAPP regional generating supplies. Day-2 also brought a more lucrative market for energy sales among competing utilities. MAPP economy energy sales, previously traded between cooperating utilities to serve load at prices approaching cost, have all but gone away.

Figure 7 below further indicates a substantial correlation between prices for regional on-peak electric energy and the wholesale cost of natural gas.

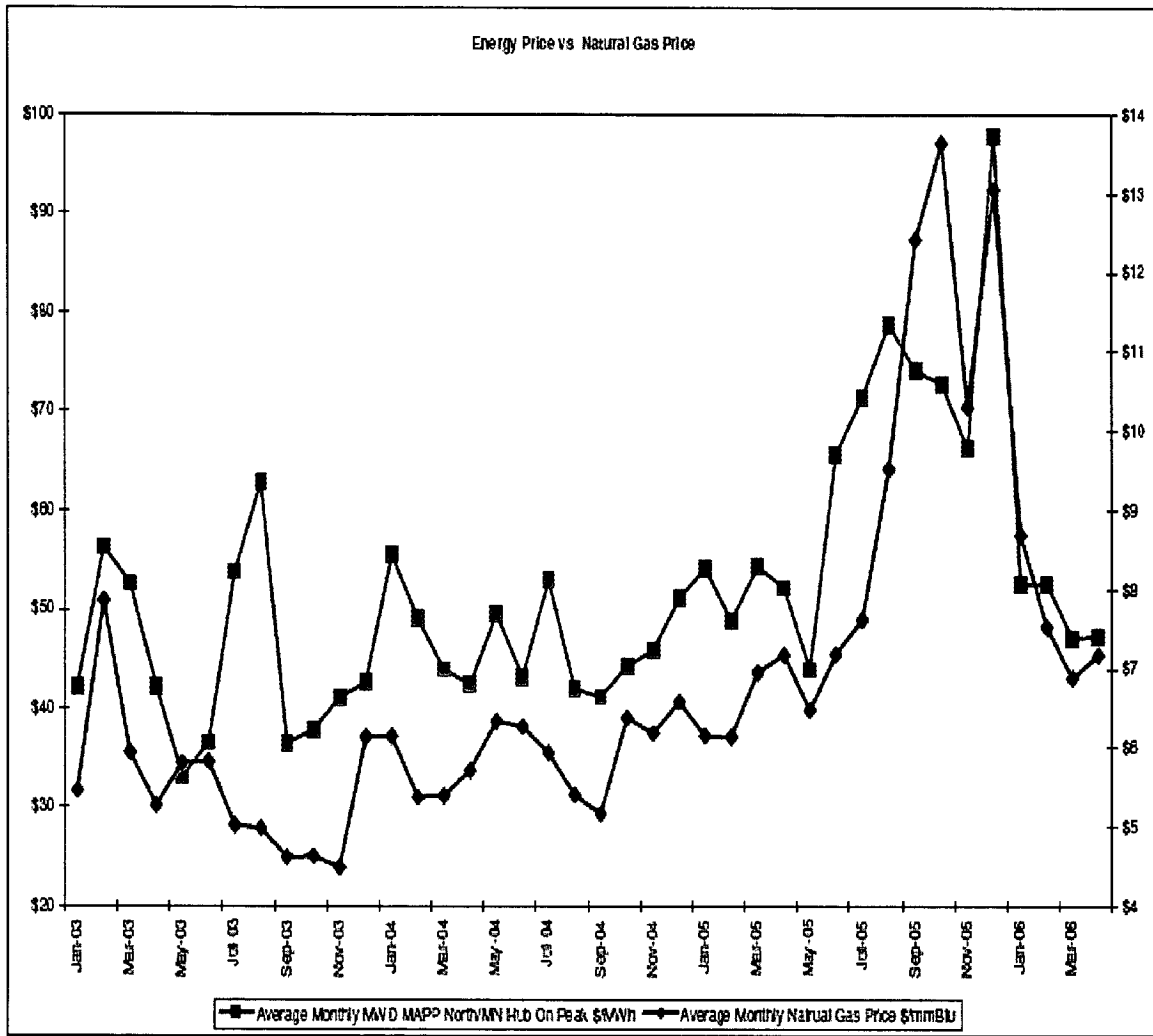


Figure 7¹

Market Purchases:

Otter Tail's total Day-2 market costs were divided by its net (injections minus withdrawals) Day-2 purchases to indicate an approximate cost per net kWh

¹ The graph in Figure 7 was presented by Minnesota Power at the May 31, 2006 Joint Stakeholder meeting in Minnesota, Dockets E-002/M-04-1970 (Xcel Energy), E-015/M-05-277 (Minnesota Power), E-017/M-05-284 (Otter Tail Power) and E-001/M-05-406

purchased from the market. The results are shown below in figure 8. Note that this approximation for any given month includes Midwest ISO billing adjustments resulting from previous months plus total administrative and uplift charges associated with all energy scheduled through the market, not just net purchases.

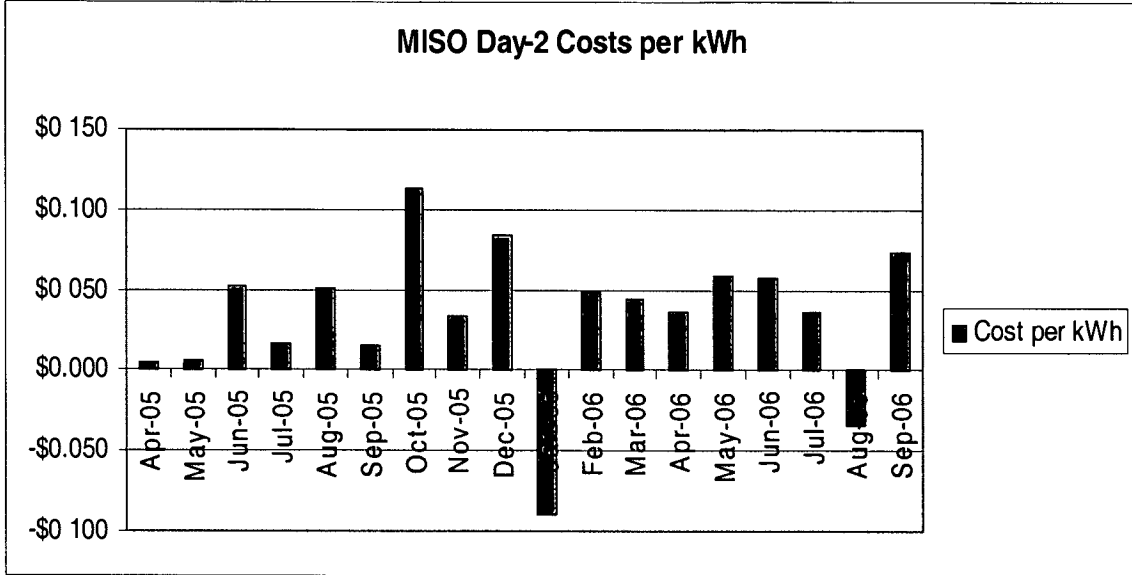


Figure 8

Figure 9 below compares Otter Tail's average bilateral purchase costs (figure 6) with the approximated average costs of net Day-2 purchases (figure 8). The comparison indicates that bilateral purchase costs have generally averaged less than Day-2 market costs. This should be expected given that the MAPP region generally has had lower production costs.

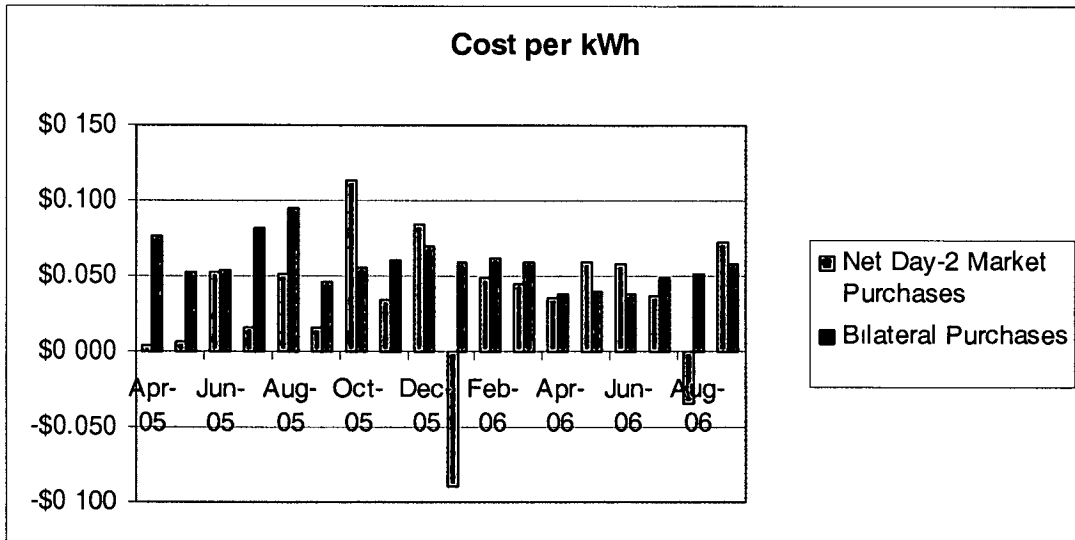


Figure 9

Midwest ISO Billing Adjustments:

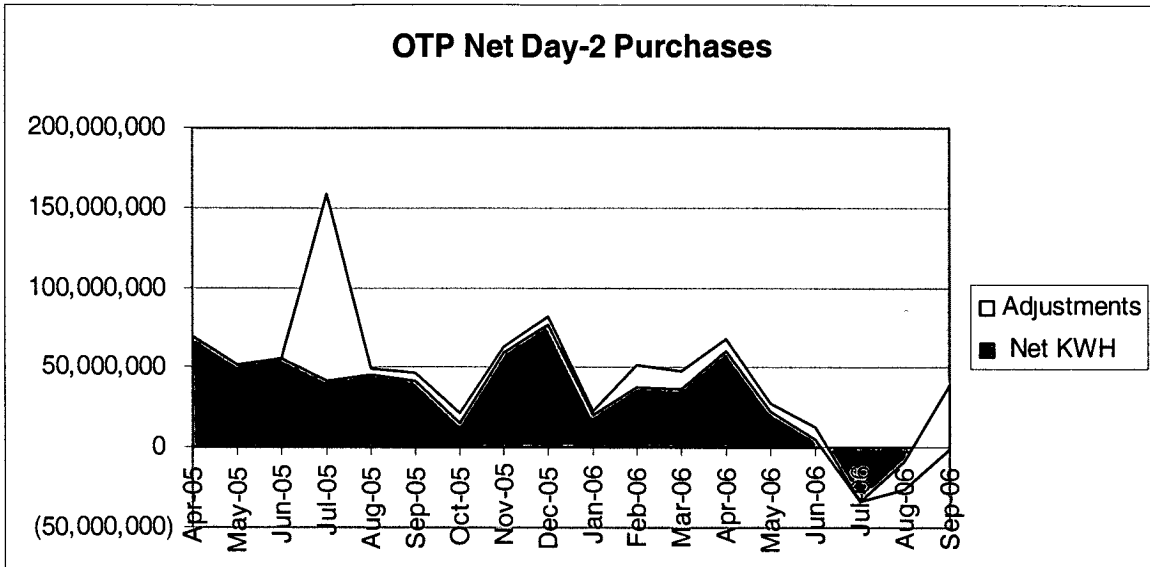


Figure 10

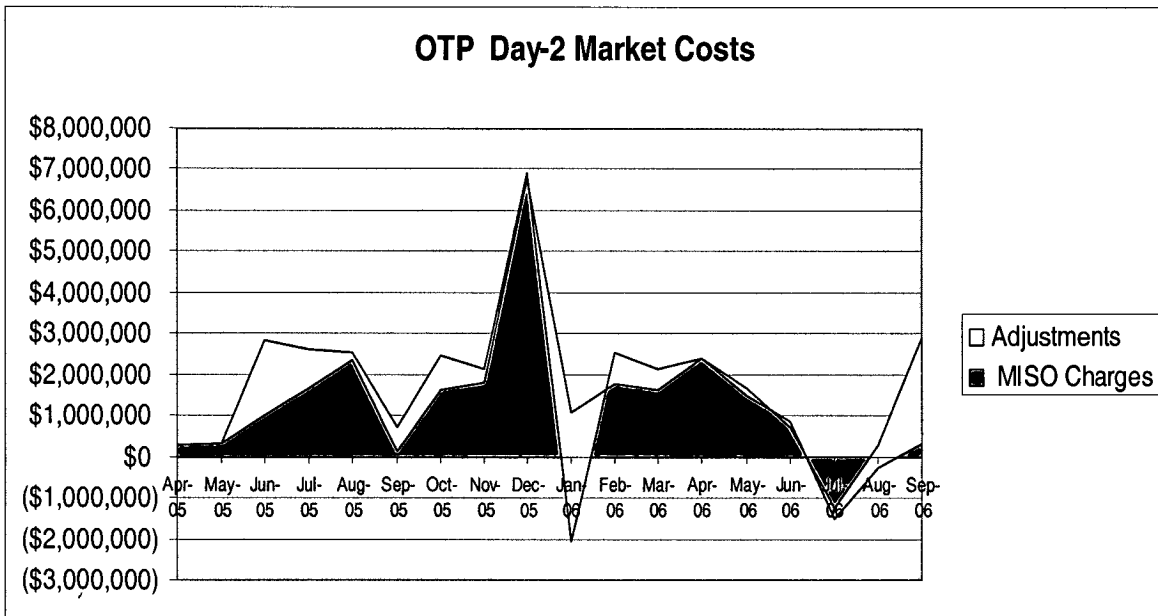


Figure 11

Figures 10 and 11 above show that Otter Tail's energy market billings have been subject to various resettlements and true-up adjustments. Otter Tail reports that the large kWh adjustment shown in figure 10 for July 2005 was caused by load not properly accounted for during April and May. Similar adjustments occurred again in September 2006 when an entity in Otter Tail's control area failed to properly report its load.

As was expected prior to market start-up, there has been some difficulty determining flows in Otter Tail's multi-utility control area. Transmission lines and even segments of transmission lines are often jointly owned and insufficiently metered because MAPP utilities have not always charged each other for transmission service.

Additional adjustments are ongoing as the Midwest ISO continues to resolve various market and other difficulties. OTP has been implementing shadow settlement software to track Midwest ISO settlements while working with an independent accounting firm to review transactions. Results of these efforts were realized in Otter Tail's March 2006 FCA filing, as reflected by the large January 2006 cost adjustment shown in Figure 11 below. This one-time downward adjustment was made based on reviews extending back to the beginning of the Day-2 market.

OTP 2005 – 2006 System Peak:

Figures 10 and 11 above further show a large increase in net Day-Ahead Asset Energy costs as reflected in the cost spike shown for December 2005 in Figure 11. Otter Tail explained that it began seasonal energy purchases in December that were scheduled through MISO as bilateral contracts for differences (CFD). When purchasing with a CFD, all energy is purchased from the Midwest ISO at the LMP price. The counter party to the transaction then either pays to or receives from Otter Tail the difference between the LMP price and the fixed bilateral contract price. Therefore, the ultimate financial result is the same.

In January only one of four Otter Tail winter purchases was completed as a CFD. This caused bilateral purchase amounts to increase and MISO purchases to decrease compared to December.

Administrative and Uplift Charges:

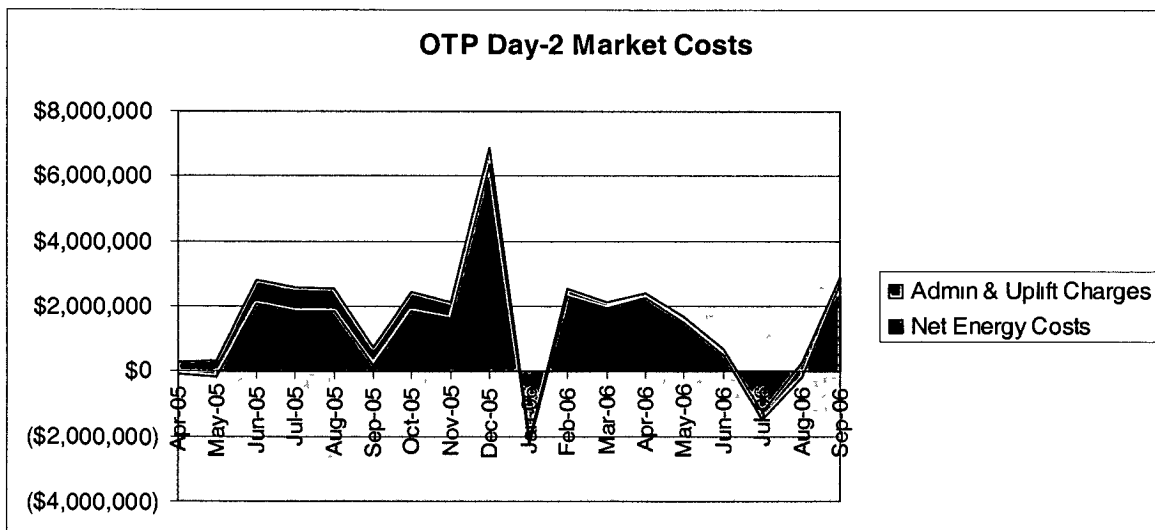


Figure 12

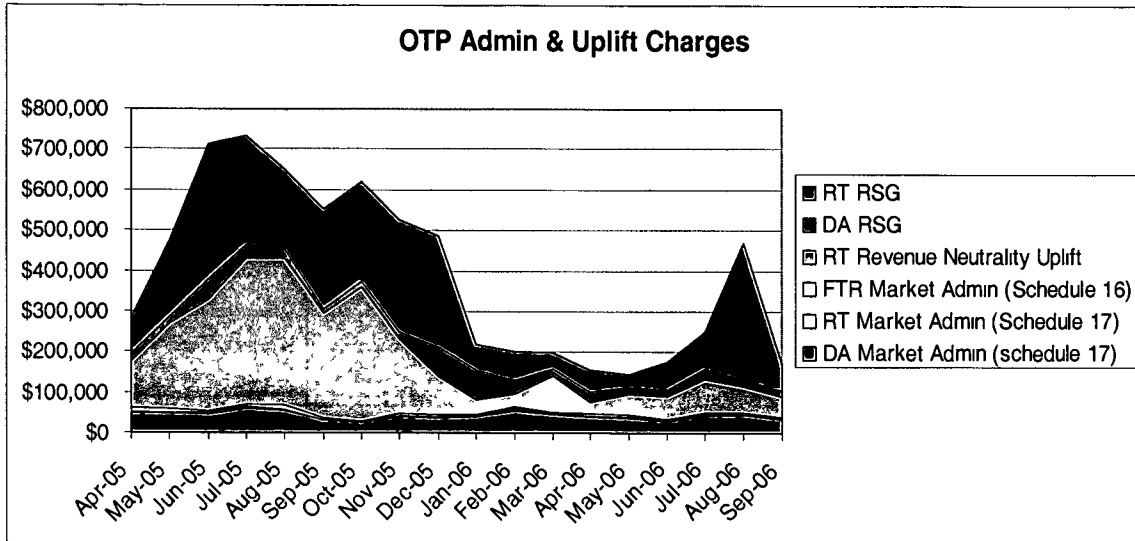


Figure 13

Figures 12 and 13 separate total Day-2 market costs to focus on overhead costs being recovered through administrative and uplift charges. Figure 12 shows that these overhead costs have not been a large part of total Day-2 energy market costs while Figure 13 shows that MISO administrative charges being recovered through tariff schedules 16 and 17 have not been a major portion of the overhead costs.

Figure 13 illustrates that uplift charges were higher than expected during the early months of market operations, but it also shows that the Midwest ISO has made progress reducing uplifts.

Figure 13 further shows that a major portion of the uplift charges has been from Real Time Revenue Sufficiency Guarantee (RT RSG) charges that uplift market revenue shortages arising from reliability needs. RT RSG charges are largely start-up costs for combustion turbines committed to maintain adequate real time system ramp rates.

RSG charges peak during the summer when combustion turbines are used the most. Figure 13 shows good progress in reducing RSG uplifts was made between the summers of 2005 and 2006. The RSG spike in early August 2006 occurred when the system was challenged by a prolonged period of footprint-wide hot weather.

Ongoing efforts to control and better manage RSG have been a top priority for the Midwest ISO. An RSG task force was created and on April 20, 2006 the Midwest ISO's Board of Directors approved three RSG task force recommendations:

1. Remove disincentives to offer dispatch flexibility. Real time LMP may not always cover the incremental energy offer of a generator that

follows instructed dispatch, thus providing disincentive to offer flexibility. The approved solution is a ramp optimization process to recover costs of a make whole payment in each hour via an uplift on the same basis as RSG for those that follow dispatch and do not change bid parameters after the day ahead clears. Implementation was planned for Fall 2006.

2. Encourage consistent offers. Changes to generation offers that remove dispatch flexibility can increase Real Time RSG Make Whole Payments. The approved solution removes certain RSG MWP eligibility for periods during which the generator changes its offer after day ahead reliability assessment commitments have been made. An implementation timeline goal of summer 2006 was under evaluation.
3. Optimize ramp. Unit commitment and associated RSG could be reduced if optimization period were over a longer horizon than five minutes. The approved solution is to perform manual re-dispatch to increase ramp available from on-line generators during peak periods. This would require make whole payments to generators dispatched out of merit order. Implementation was expected in Fall 2006.

Another important RSG issue surfaced last fall when the Midwest ISO discovered that it was interpreting its tariff improperly by failing to assess RSG charges to virtual transactions. The Midwest ISO considered this a tariff discrepancy and filed corrective tariff changes during October 2005 in FERC Docket No. ER04-691-078 that would have made RSG charges inapplicable to virtual transactions.

On April 25 2006 the FERC issued an order denying the tariff changes and requiring the Midwest ISO to recalculate rates and make refunds with interest to reflect correct allocations of RSG costs to virtual supply offers. In response, MISO and many stakeholders including NSP, Otter Tail and FPL, filed requests for rehearing, which were granted by the FERC in May. On October 26, 2006 the FERC issued its order on reconsideration reaffirming its previous order that RSG charges apply to virtual transactions, but reversing its decision to recalculate rates and issue refunds, The FERC ordered compliance filings within 30 and 60 days. Several parties, including Xcel Energy filed requests for rehearing/clarification of the October 26 Order.

Intersystem Sales:

Increased energy prices during 2005 combined with increased sales opportunities in the new Day-2 energy market to bring more revenue from intersystem sales margins. Figure 14 below shows that Otter Tail's margins from both asset based and non-asset based intersystem sales increased significantly with the start of the Day-2 market.

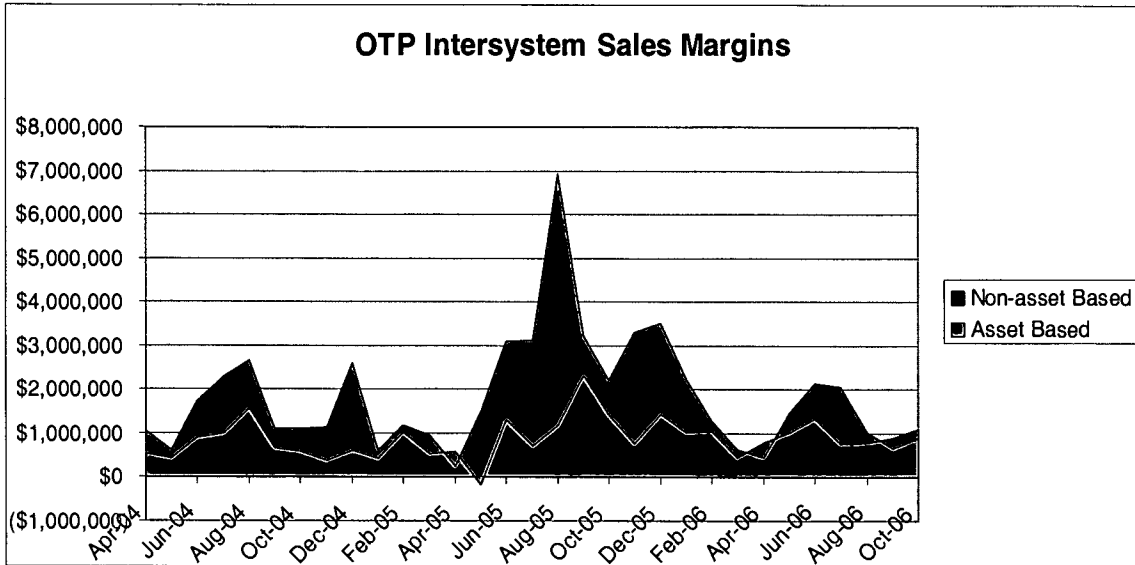


Figure 14

Figure 15 provides the corresponding intersystem sales volumes.

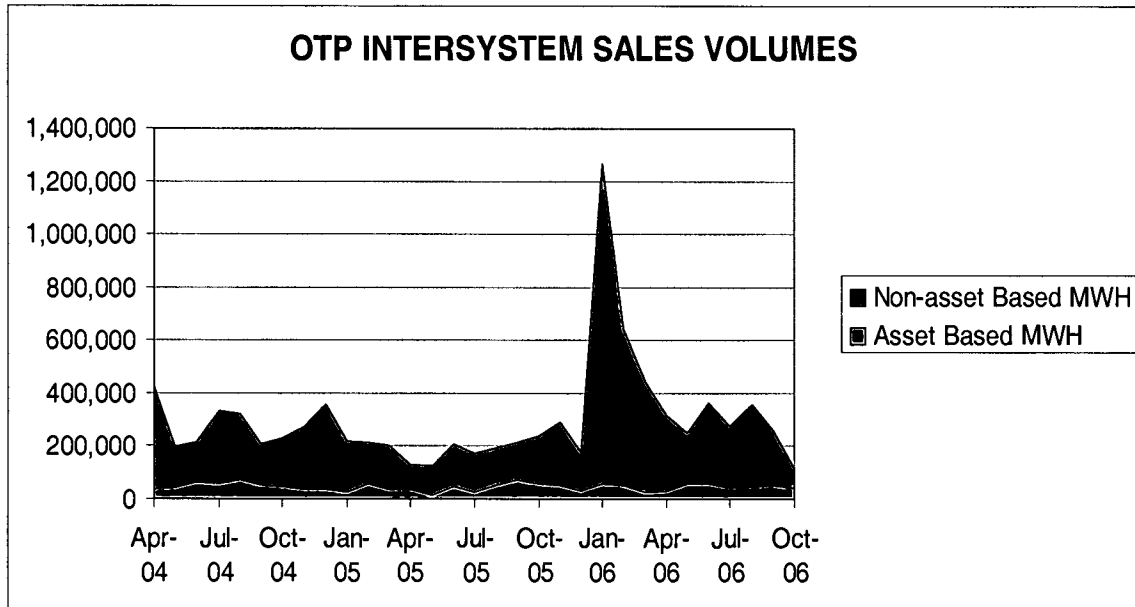


Figure 15

North Dakota ratepayers benefited from these sales as the increased margins were included as a credit towards Otter Tail's revenue requirements. Without these margins serving as a revenue credit the Company would likely have had to file to increase rates. Otter Tail provided the table below showing the positive impact of intersystem sales margins on Otter Tail's return on equity for 2004 and 2005.

Summary of ND Benefits From Wholesale Margin Revenue Credits

	2004	2005
ROE earned under PBR	13.5%	12.6%
Contribution to ROE from non-asset margins	1.8%	3.1%
Subtotal - ROE without non-asset margins	11.7%	9.5%
Contribution to ROE from asset margins*	2.2%	2.9%
ND ROE without revenue credit for wholesale margins	9.5%	6.6%

* amount over that included in base rates from last rate case

Traditionally, margins from intersystem sales have been treated as test year revenues during rate cases. As of the expiration of Otter Tail's performance based regulation plan at the end of 2005, Otter Tail no longer reports margins from non-asset based sales as regulated earnings. Instead, an associated portion of overhead costs is allocated below the line. Otter Tail experienced a large amount of non-asset based sales margins during 2005 due mostly to successful virtual transactions. Virtual transaction opportunities have tightened during 2006 resulting in a drop in Otter Tail's non-asset based intersystem sales margins, including net losses for the months of April, September and October 2006 as better shown in figure 16 below.

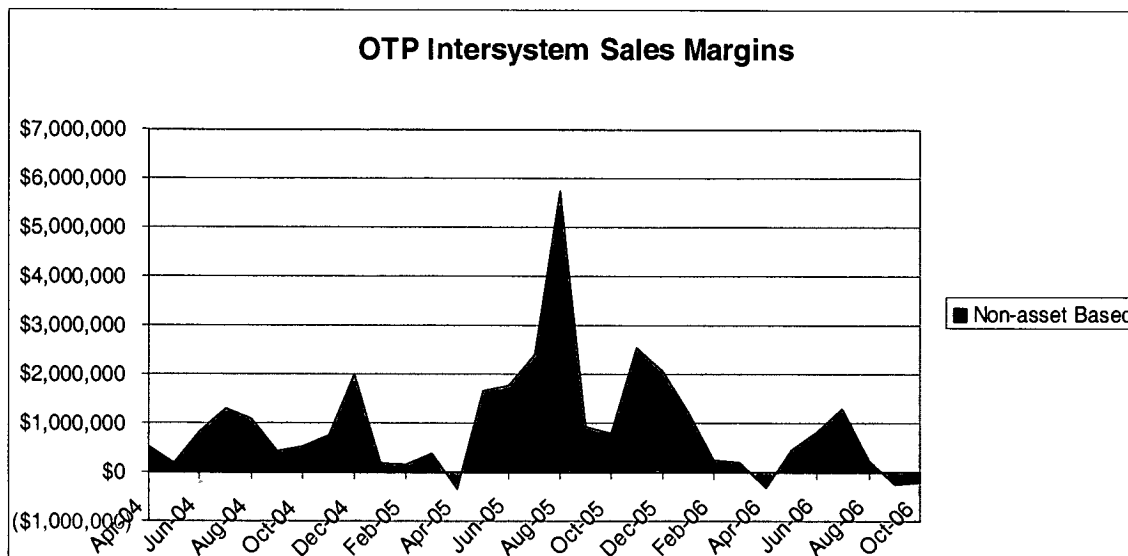


Figure 16

The ND PSC has approved a revenue sharing mechanism whereby MDU returns to customers 85% of intersystem sales margins in excess of those included in rate case test year revenues. It appears that something similar could be considered for Otter Tail in its next rate case.

Prepared By: Jerry Lein

Attachments: 1. Summary of other state proceedings
2. Summary of the 32 Midwest ISO TEMT charges
3. Summary of costs billed to Otter Tail for each charge type.

Attachment 1

OTHER STATE PROCEEDINGS:

Minnesota:

The MN PUC issued its initial decision on December 21, 2005 accepting in part and rejecting in part petitions filed by Xcel Energy in Docket No. E-002/M-04-1970 and Otter Tail in Docket No. E-017/M-05-284. The decision also addressed similar petitions filed by Minnesota Power and by Interstate Power and Light.

In summary, the MN PUC's 2005 decision approved fuel clause recovery only for net energy-related MISO costs. It rejected FCA recovery of administrative and uplift charges, which the utilities could apply to recover annually. The PUC further required refunds with interest of non-energy costs already recovered. The PUC also limited real-time market purchases to no more than 5% of total retail purchases. The PUC ordered that the policy being adopted would be effective only for one year while the PUC investigated alternative methods for serving customers at low cost. The PUC further ordered:

Each petitioner shall, in its next general electric rate case, examine a revenue-sharing or benchmarking system of off-system sales or other significant revenue streams attributable to MISO's Day 2 market that would offset increased costs from participation in MISO's Day 2 market.

Petitions for reconsideration were filed by several parties. NSP and Minnesota Power termed the prescribed accounting treatment unworkable and sent letters to the Midwest ISO threatening to withdraw via regulatory-out clauses in their Transmission Owners (TO) agreements. The Midwest ISO filed a controversial petition to intervene with comments urging the MN PUC to reconsider. In early February 2006 the MN PUC granted reconsideration and gave parties 60 days to file an agreement with recommendations for permanent accounting treatments.

On June 23, 2006 the parties, including NSP, OTP, MN DOC and OAG, filed their Joint Report and Recommendations (JRR) essentially agreeing that MISO costs should continue to be recovered through the FCA except for Schedules 16 and 17 charges, which would be deferred until the next rate case.

On November 9, 2006, the MN PUC accepted the JRR and decided to continue allowing full FCA recovery of MISO market costs except for Schedules 16 and 17 charges, which are to be refunded to customers going back to market start-up and booked into a deferred account as a regulatory asset for an amortization to be determined during the next rate case.

South Dakota:

Petitions for FCA recovery have been approved by the SD PUC and all MISO Day-2 market costs are being recovered through the SD FCA.

Montana:

Montana does not have a Fuel Clause Adjustment.

Attachment 2

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 and Carve-Out Grandfathered Agreement Transaction congestion costs for 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

Attachment 3

Otter Tail Account 555 MISO Charges

<u>Charge Type</u>	<u>4/30/05</u>	<u>5/31/05</u>	<u>6/30/05</u>	<u>7/31/05</u>	<u>8/31/05</u>	<u>9/30/05</u>	<u>10/31/05</u>
DA Mkt Admin	48171	47025	45716	60501	54513	30093	24341
DA Asset Energy	2099530	1681995	2700584	3172933	3939956	1912215	2048666
DA FBT Congestion	3000	3200	-131	99	-771	-12401	10133
DAFBT Loss	33000	7466	4401	145	5000	291630	233777
DA Congestion Rebate on COGA	-10952						
DA Losses Rebate on COGA	-110736						
DA Congestion Rebate on Option B GFA						11291	-9940
DA Losses Rebate on Option B GFA						-143499	-115011
DA Non-Asset Energy	-1102070	-604717	-1095695	-709244	-926177	-1014926	-688202
DA Rev Suff Guar Distribution	21545	15650	52063	32170	22030	10589	15974
DA Rev Suff Guar Make-Whole Pmt							
DA Virtual Energy	516162	78762					
FTR Mkt Admin	11478	10908	2770	3730	9452	6913	4105
FTR Hourly Allocation	-159	-13000	-110515	-291247	-260819	11318	11372
FTR Monthly Allocation		-5631	-13	-611			-19824
FTR Transaction		4	-33565				19146
FTR Yearly Allocation							
RT Mkt Admin	3243	1494	4914	5384	2956	932	429
RT Asset Energy	-684082	-907986	-780206	-430020	-428203	-1152307	-239175
RT FBT Congestion						1	
RT FBT Loss							
RT Congestion Rebate on COGA	11						
RT Loss Rebate on COGA	-59						
RT Distribution of Losses	-300147	-309711	-374185	-707606	-539729	-267593	-229786
RT Misc							
RT Non-Asset Energy							
RT Net Inadvertent	-16778	-36089	-38709	-111259	-76975	-41261	-8692
RT Rev Neutrality Uplift	111271	209382	273843	361188	364021	255726	329324
RT Rev Suff Guar First Pass Distribution	86284	188203	334295	270526	196949	247625	244352
RT Rev Suff Guar Make Whole Pymt				2339			
RT Uninstrctede Deviation	57152	62	32824		4977	702	7058
RT Virtual Energy	-482273	-57015					
Net MISO Charges for Retail	283591	310003	1018391	1659028	2367178	147049	1638049
Adjustments			1805721	941272	168937	581397	834178
Total MISO	283591	310003	2824113	2600300	2536115	728446	2472226
Energy							
Net DA Asset Energy MWH	79978	50816	52097	40885	65388	44806	48374
Net DA Non-Asset Energy MWH	-23058	-16654	-18083	-7154	-11267	-12488	-8069
Net RT Asset Energy MWH	11921	18041	20962	7773	-8293	8904	-24454
Net RT Non-Asset Energy MWH							
Net KWH for Retail	68841000	52203000	54976000	41504000	45828000	41222000	15851000
Adjustments				116955796	3793658	5768344	6000436
Net MISO KWH	68841000	52203000	54976000	158459796	49621658	46990344	21851436

Attachment 3

Otter Tail Account 555 MISO Charges

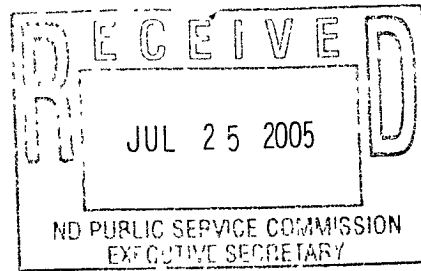
<u>Charge Type</u>	<u>11/30/05</u>	<u>12/31/05</u>	<u>1/31/06</u>	<u>2/28/06</u>	<u>3/31/06</u>	<u>4/30/06</u>	<u>5/31/06</u>
DA Mkt Admin	39662	37082	38986	54979	45704	40046	37785
DA Asset Energy	2004387	10457381	4093735	3238776	1894019	2416694	3982868
DA FBT Congestion	61729	150300	13111	10959	10001	3892	119
DAFBT Loss	225214	413860	248271	252199	272854	99884	2576
DA Congestion Rebate on COGA							
DA Losses Rebate on COGA							
DA Congestion Rebate on Option B GFA	-58775	-147767	-12703	-10640	-9767	-4008	
DA Losses Rebate on Option B GFA	-111032	-204345	-122278	-124279	-134475	-46723	
DA Non-Asset Energy	-526634	-1048869	-541803	-397138	-406694	-1307754	-2745342
DA Rev Suff Guar Distribution	18502	72268	73450	34051	17289	24350	15710
DA Rev Suff Guar Make-Whole Pmt					-11518		
DA Virtual Energy							
FTR Mkt Admin	6022	3842	2557	5203	3746	4656	5107
FTR Hourly Allocation	-29395	77198	-14596	11302	-11767	5502	-32946
FTR Monthly Allocation	-2635	-10228	-6681	-2294	-5772	-6572	-4684
FTR Transaction						15994	
FTR Yearly Allocation							
RT Mkt Admin	1966	3576	5047	5401	1879	3520	2711
RT Asset Energy	-3634	-3019915	-927473	225255	113497	1168180	43904
RT FBT Congestion							
RT FBT Loss							
RT Congestion Rebate on COGA							
RT Loss Rebate on COGA							
RT Distribution of Losses	-246368	-337434	-207056	-254241	-170480	-107628	-142245
RT Misc							
RT Non-Asset Energy		-27408	-1622235	-1353782	-127724	13739	238766
RT Net Inadvertent	-26988	-43631	-30492	-14306	6198	75	343
RT Rev Neutrality Uplift	183257	94456	34543	31057	90637	28129	51651
RT Rev Suff Guar First Pass Distribution	275032	275535	63316	69332	39744	53617	30827
RT Rev Suff Guar Make Whole Pymt							
RT Uninstrucede Deviation	1191	5090	83	997	270	373	211
RT Virtual Energy							
Net MISO Charges for Retail	1811499	6750990	1087780	1782830	1617640	2405965	1487361
Adjustments	333123	138949	-3125519	738698	507260	2834	180045
Total MISO	2144622	6889939	-2037738	2521528	2124900	2408799	1667406
Energy							
Net DA Asset Energy MWH	82267	124048	99675	65443	44119	67358	103447
Net DA Non-Asset Energy MWH	-6063	-7268	-9649	-6280	-8657	-33773	-89697
Net RT Asset Energy MWH	-16976	-40146	-23666	10626	3074	27327	-76
Net RT Non-Asset Energy MWH		-257	-45490	-31253	-2022	261	8948
Net KWH for Retail	59228000	76377000	20870000	38536000	36514000	61173000	22621387
Adjustments	4442224	5768257	2069321	13218000	11391357	6479831	5602549
Net MISO KWH	63670224	82145257	22939511	51755183	47907185	67653787	28223936

Attachment 3

Otter Tail Account 555 MISO Charges

<u>Charge Type</u>	<u>6/30/06</u>	<u>7/31/06</u>	<u>8/31/06</u>	<u>9/30/06</u>	<u>10/31/06</u>
DA Mkt Admin	28673	41168	44035	33619	43148
DA Asset Energy	4082497	1595634	2229621	1241973	1427714
DA FBT Congestion	4023	24553	67668	24355	71081
DAFBT Loss	160478	322256	468847	221176	242042
DA Congestion Rebate on COGA					
DA Losses Rebate on COGA					
DA Congestion Rebate on Option B GFA	-3903	-25081	-66681	-23779	-71048
DA Losses Rebate on Option B GFA	-78833	-157823	-231539	-108884	-118568
DA Non-Asset Energy	-2954469	-598956	-989846	-598614	-575960
DA Rev Suff Guar Distribution	16594	23204	17023	12579	10684
DA Rev Suff Guar Make-Whole Pmt	-7586		-2079		
DA Virtual Energy					
FTR Mkt Admin	1590	4551	3187	4287	4901
FTR Hourly Allocation	-5387	23545	-118774	14472	-25139
FTR Monthly Allocation	-2489	-2134	-30584	-14558	-1569
FTR Transaction					
FTR Yearly Allocation					
RT Mkt Admin	2689	3983	3112	2021	2161
RT Asset Energy	-356637	-2684523	-1779920	-451993	249319
RT FBT Congestion					
RT FBT Loss					
RT Congestion Rebate on COGA					
RT Loss Rebate on COGA					
RT Distribution of Losses	-145438	-283317	-303301	-169691	-309957
RT Misc					55
RT Non-Asset Energy	-9295	22862	28415	19091	68280
RT Net Inadvertent	-8911	-10656	928	-7001	-8343
RT Rev Neutrality Uplift	56619	84119	66229	51601	41145
RT Rev Suff Guar First Pass Distribution	69825	91043	335827	65761	167377
RT Rev Suff Guar Make Whole Pymt					
RT Uninstrctede Deviation	779	2078	934	846	286
RT Virtual Energy					
Net MISO Charges for Retail	850819	-1523497	-256898	317262	1217610
Adjustments	-148645	278642	542570	2584245	773022
Total MISO	702174	-1244855	285672	2901506	1990632
Energy					
Net DA Asset Energy MWH	95222	20333	18050	25271	20661
Net DA Non-Asset Energy MWH	-70825	-8245	-11915	-13157	-9139
Net RT Asset Energy MWH	-18575	-46595	-33614	-13097	3282
Net RT Non-Asset Energy MWH	-178	245	1066	493	1768
Net KWH for Retail	5644355	-34261938	-26414104	-489147	16572066
Adjustments	6618137	288528	17968805	40287676	17107305
Net MISO KWH	12262492	-33973410	-8445299	39798529	33679371

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



July 20, 2005



Ms. Illona Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

Dear Ms. Jeffcoat-Sacco

Subject: CASE NO. PU-05-131

Enclosed are two approved copies of Otter Tail Power Company's Cost of Energy Adjustment Clause rate schedule M-60N. A motion by the North Dakota Public Service Commission approved the rate schedule on July 13, 2005. The rate schedule is effective with services rendered on and after August 1, 2005.

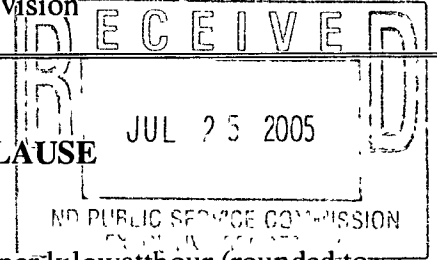
If you have any questions, please call me at 218-739-8289.

Sincerely yours,

A handwritten signature in cursive script that reads "Bernadeen Brutlag".

Bernadeen Brutlag, Manager
Regulatory Services
jrb

Enclosures



COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

Energy costs from actual months 1, 2, 3, 4 and 5 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, 4 and 5 equals the cost of energy adjustment for month 6.

The applicable adjustment will be applied effective on any billing dated on or after the first day of each calendar month. The average cost of energy shall be determined as follows:

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3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. Less the fuel related costs recovered through intersystem sales.





Public Service Commission

State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www.psc.state.nd.us
e-mail ndpsc@state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

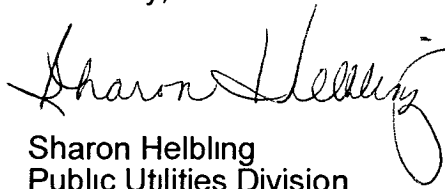
July 13, 2005

Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496

Dear Ms. Brutlag

On July 13, 2005, the Commission approved Otter Tail Corporation's cost of fuel adjustment clause, Case No. PU-05-131.

Sincerely,


Sharon Helbling
Public Utilities Division

sdh

Enclosure

MOTION

July 13, 2005

APPROVED

DATE: 7-13-05
KMF

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

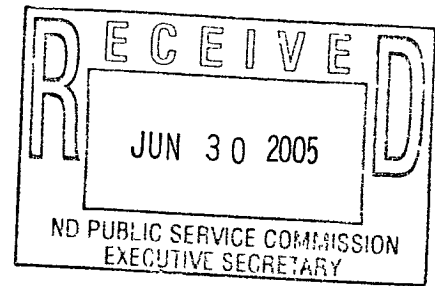
I move the Commission approve Case No. PU-05-131, Otter Tail Corporation's
Cost of Fuel Adjustment Clause tariff.

JRL/sdh

215 South Cascade Street
PO Box 496
Fergus Falls Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)

VIA Electronic Mail and Overnight Delivery

June 30, 2005



Ms. Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505

SUBJECT Revision to Compliance filing in Docket Number PU-05-131 Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY's (Otter Tail) Application for Fuel Clause Adjustment Revision for MISO Day 2 charges

Dear Ms. Jeffcoat-Sacco:

In Docket Number PU-05-131 the North Dakota Public Service Commission (NDPSC) required the following in its Interim Order, dated April 6, 2005

4. MDU, NSP and Otter Tail shall work together to develop standardized appropriate FCA tariff language.
5. MDU, NSP and Otter Tail shall file proposed FCA tariff revisions by May 15, 2005.

Otter Tail filed its compliance filing on May 13, 2005, but the language was placed incorrectly in the tariff, leaving the accounting treatment unclear. The attached tariff has the language in the appropriate place.

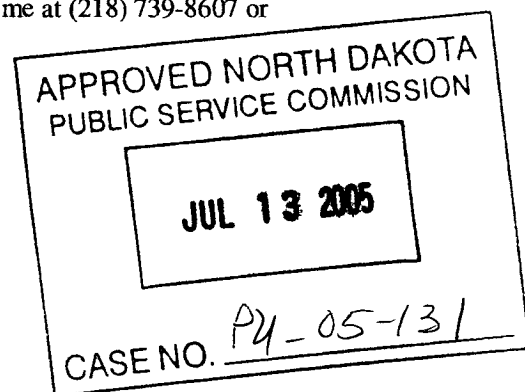
Enclosed is an original and seven copies of Otter Tail Power Company's proposed Tariff sheet 98 (volume1), rate designation M-60N, page 1 of 1 (both normal and red-line versions). An electronic copy of the Compliance filing is being sent via email to you at ijeffcoatsacco@state.nd.us and to Sandi Scott at slscott@state.nd.us.

If you have any questions regarding this filing, please contact me at (218) 739-8607 or pbeithon@otpc.com

Yours very truly,

A handwritten signature in black ink, appearing to read "Pete Beithon", written over a horizontal line.

Pete Beithon
Manager, Regulatory Economics
Enclosure



COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

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3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. ~~Net costs 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.~~
5. ~~Less the fuel related costs recovered through intersystem sales.~~

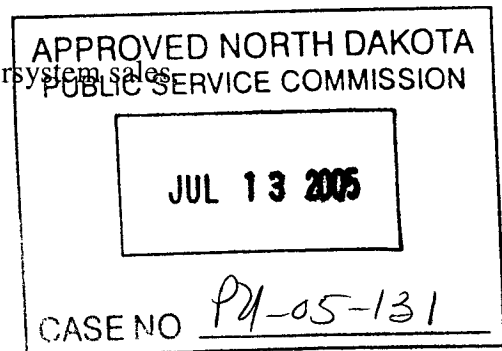
COST OF ENERGY ADJUSTMENT CLAUSE

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3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. Less the fuel related costs recovered through intersystem sales



NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Approved: July 13, 2005
Case No. PU-05-131

RATES EFFECTIVE with bills rendered
on and after August 1, 2005, in ND

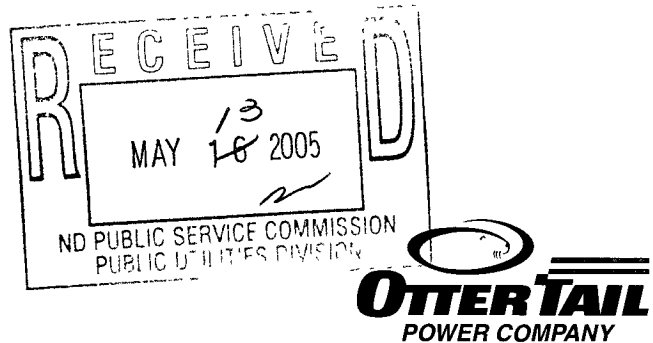
APPROVED: Bernadeen Brutlag
Manager, Regulatory Services

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)

VIA Electronic Mail and Overnight Delivery

May 13, 2005

Ms Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505



SUBJECT Compliance filing in Docket Number PU-05-131 Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY's Application for Fuel Clause Adjustment Revision for MISO Day 2 charges

Dear Ms Jeffcoat-Sacco:

In Docket Number PU-05-131 the North Dakota Public Service Commission (NDPSC) required the following in its Interim Order, dated April 6, 2005

- 4 MDU, NSP and Otter Tail shall work together to develop standardized appropriate FCA tariff language
- 5 MDU, NSP and Otter Tail shall file proposed FCA tariff revisions by May 15, 2005

This compliance filing includes proposed language agreed upon by MDU, NSP and Otter Tail (with NDPSC Staff input) The language is as follows

"4 Net costs 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 "

Enclosed is an original and seven copies of Otter Tail Power Company's proposed Tariff sheet 98 (volume 1), rate designation M-60N, page 1 of 1 An electronic copy of the Compliance filing is being sent via email to you at jeffcoatsacco@state.nd.us and to Sandi Scott at slscott@state.nd.us.

If you have any questions regarding this filing, please contact me at (218) 739-8607 or pbeithon@otpc.com

Yours very truly,

Pete Beithon
Manager, Regulatory Economics

Enclosure

8

PU-05-131

Pages 2

Compliance filing

by Otter Tail Corporation by
05/13/2005 CC Comm Legal Illona, Annette, Mike

COST OF ENERGY 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 energy is above or below 1.6473¢ per kilowatt-hour. The average cost of energy per kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

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5. Less the fuel related costs recovered through intersystem sales.

T

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff

Case No. PU-05-131

Montana-Dakota Utilities Co.
Cost of Fuel Adjustment Clause
Tariff

Case No. PU-05-135

Northern States Power Company
Cost of Fuel Adjustment Clause
Tariff

Case No. PU-05-147

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **7th day of April, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of

Interim Order

The envelopes were addressed as follows

Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496
Cert. No. 7003 2260 0001 3517 9749

Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501
Cert. No. 7003 260 0001 3517 9756

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58208-2747
Cert. No. 7003 2260 0001 3517 9763

Sharon Helbling further deposes and says that on the **7th day of April, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes by regular mail, with postage fully prepaid, securely sealed, each containing a photocopy of the same

Bruce Gerhardson
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496

James P Johnson
Xcel Energy Services
800 Nicollet Mall Ste 2900
Minneapolis MN 55402

Dan Kuntz
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Each address shown is the respective addressee's last reasonably ascertainable post office address

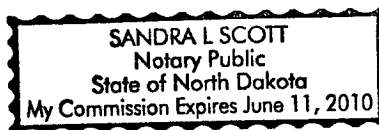


Subscribed and sworn to before me
this **7th day of April, 2005**



Notary Public

SEAL



MOTION

April 6, 2005

APPROVED

DATE 4-6-05
KMF

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

**Montana-Dakota Utilities Co.
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-135

**Northern States Power Company
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-147

I move the Commission adopt the Interim Order prescribing initial accounting treatments for MISO Day-2 energy market costs, Case Nos PU-05-131, PU-05-135 and PU-05-147.

JRL/sdh

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

**Montana-Dakota Utilities Co.
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-135

**Northern States Power Company
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-147

INTERIM ORDER

April 6, 2005

On March 1, 2005, in Case No PU-05-131, Otter Tail Corporation, d/b/a Otter Tail Power Company (Otter Tail) filed revisions to its Fuel Clause Adjustment (FCA) tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new regional wholesale electric energy market. The new market, known as Day 2, will operate under the Midwest Independent Transmission System Operator, Inc 's (Midwest ISO) Transmission Energy Markets Tariff (TEMT) as approved by the Federal Energy Regulatory Commission (FERC).

Also on March 1, 2005, in Case No. PU-05-135, Montana-Dakota Utilities Co (MDU), a Division of MDU Resources Group, Inc filed similar revisions to its FCA tariff to be effective with implementation of the new Day 2 energy markets on April 1, 2005.

On March 5, 2005, in Case No PU-05-147, Northern States Power Company d/b/a Xcel Energy (NSP) filed similar revisions to its FCA tariff

On March 9, 2005, the Commission suspended the tariff revisions filed by Otter Tail and MDU On March 23, 2005, the Commission suspended the tariff revisions filed by NSP.

Also on March 23, 2005, the Commission discussed the proposed tariff revisions with Commission staff and all three applicants during an informal hearing.

Implementation of the Midwest ISO's Day 2 energy market changes the way participating utilities procure energy to serve load. In the past utilities obtained energy directly from utility-owned or contracted generating resources and recovered the costs of generating fuel or purchased energy from consumers through the FCA billing

mechanism. Under the new Day 2 market, generation not self-scheduled by the utility is centrally dispatched into the market and receives payment equal to the full locational marginal price (LMP) per megawatt-hour (MWH) at the generator location. Energy to serve load that is not self-scheduled by the utility is purchased from the Day 2 market at a price equal to the full LMP per MWH at the load location. The LMP at any particular location consists of three components. Self-scheduled transactions are exempted from the energy component, but are subject to the remaining marginal loss and congestion components. As a result of these changes, it is necessary to credit the new market revenues against the costs being paid for energy before passing the net costs on to consumers.

The differences between the generator LMP and load LMP reflect the cost of transmission grid congestion between generator and load locations. Utilities may hedge against the costs of congestion by holding financial transmission rights (FTR) for particular transmission paths. Congestion revenues collected from an FTR path are paid to the FTR holder. Therefore, it will be necessary under Day 2 operations to net FTR revenues and charges against the costs of purchased energy being passed on to consumers.

Additionally, the Midwest ISO will charge FERC approved cost adders for recovering market implementation and operating costs. These cost adders include TEMT Schedule 16 and 17 charges as well as uplift charges for costs that have been approved for recovery from the entire market.

The applicants originally proposed two accounting methodologies. NSP and MDU proposed the use of sub-accounts under FERC Account 555, Purchased Power Energy Consumed, to arrive at a net cost of purchased power from the Day-2 energy market. Under section 69-09-02-39(4)(c) of the North Dakota Administrative Code, the resulting net cost of energy recorded in Account 555 would be recovered dollar-for-dollar from consumers through FCA billings. Otter Tail initially proposed to maintain separate FERC revenue accounts and credit these against expenses from Account 555 (purchased energy) and 501 (fuel consumed) within the fuel clause adjustment mechanism. During the informal hearing, Otter Tail stated that it now prefers to use sub-accounts under Account 555 as proposed by NSP and MDU because this method will be required in other jurisdictions. During the informal hearing the applicants agreed they would work together to try and standardize the tariff language being proposed by each company.

The Commission finds that sufficient Day 2 operational experience and market maturity will be necessary before adopting any permanent accounting treatment for the new market costs. Consequently, an interim plan is necessary if the applicants are to participate in the Day 2 energy market. Therefore, the Commission finds the proposed sub-accounts under FERC Account 555 acceptable for interim fuel clause recovery of

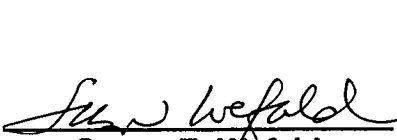
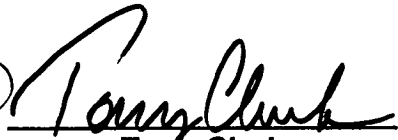
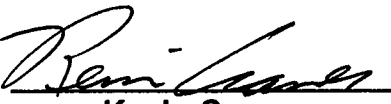
the net costs of energy, including TEMT Schedules 16 and 17 charges and FERC approved uplift charges, purchased through the Midwest ISO Day 2 energy market to serve native load. The Commission further finds that amounts collected under this interim treatment should be subject to refund with interest in the event the Commission ultimately orders a different or modified accounting treatment that results in lower charges.

Order

The Commission Orders:

1. On an interim basis, the net costs of energy purchased through the Midwest ISO Day 2 energy market for serving native load, including TEMT Schedule 16 and 17 charges and FERC approved uplift charges, are to be recorded as a cost of purchased energy under FERC Account 555.
2. The recovery of Day 2 costs, net of any applicable revenues, are subject to refund plus interest in the event the Commission ultimately orders a different or modified accounting treatment.
3. Each Midwest ISO billing line item is to be tracked individually in a separate sub-account under Account 555.
4. MDU, NSP and Otter Tail shall work together to develop standardized appropriate FCA tariff language.
5. MDU, NSP and Otter Tail shall file proposed FCA tariff revisions by May 15, 2005.

PUBLIC SERVICE COMMISSION

		
Susan E. Wefald Commissioner	Tony Clark President	Kevin Cramer Commissioner

North Dakota Public Service Commission
INFORMAL HEARING
March 23, 2005

Otter Tail Corporation
Cost of Energy Adjustment
Tariff

PU-05-131
Filed: 3/1/05

Montana-Dakota Utilities Co.
Cost of Energy Adjustment
Tariff

PU-05-135
Filed: 3/1/05

Northern States Power Company
Cost of Energy Adjustment
Tariff

PU-05-05-147
Filed: 3/5/05

Summary of Proposals: All three regulated electric utilities have filed fuel clause adjustment tariff changes to reflect new accounting procedures beginning April 1st when the MISO Day-2 market is expected to be implemented. The changes would allow for revenues received from FTRs and generation serving native load to be credited against the LMP prices and other MISO charges paid for energy delivered to native load. If the Commission determines any waivers from the existing fuel clause rules are needed, then the Companies request those waivers be granted.

Procedural History: On March 9, 2005 the Commission suspended the filings of MDU and Otter Tail. NSP's filing is expected to be suspended March 23rd.

Discussion: The companies have identified two accounting alternatives that would accomplish the same result, but vary in methodology. NSP and MDU proposed a "netting" treatment using sub-accounts under FERC Account 555 Purchased Power Energy Consumed to provide a net cost of purchased power from the day-2 energy market. Otter Tail now prefers the "netting" under Account 555 methodology, though it originally proposed to maintain separate FERC revenue accounts and credit these against expenses from Account 555 (purchased energy) and 501 (fuel consumed) within the fuel clause adjustment mechanism. Otter Tail explains that the MNPUC is expected to adopt the "netting" Account 555 on March 24th as an interim methodology and Otter Tail prefers to use the same method in all jurisdictions.

So far the FERC has not provided any guidance, though late last year it did issue a preliminary inquiry as to whether it should issue a Notice of Inquiry.

In order to implement the "netting" under Account 555 methodology, the companies request an order from the Commission requiring that all costs and revenues for serving native load from MISO day-2 energy markets be netted

through account 555 as a cost of purchased power. It appears no waiver of existing fuel clause rules would be necessary under such accounting treatment. See attached ND Admin. Code section 69-09-02-39(4)(c).

NSP suggests proposes to provide a breakdown of the various components of MISO TEMT charges in monthly FCA filings including:

- Total Purchases from MISO related to linked transactions;
- Total payments from MISO related to self-scheduled or must run transactions;
- Total congestion and marginal loss costs charges;
- Total FTR credits and expenses, and
- Total Marginal Loss Compensation revenue.

Recommendation: I recommend the Commission approve the proposed fuel clause adjustment tariff changes and order that all costs and revenues for serving native load from MISO Day-2 energy markets be netted through account 555. For initial reporting requirements, I recommend the Commission require the companies to submit a breakdown of TEMT charges as proposed by NSP with all FCA filings. These initial requirements can be evaluated and modified if needed after more experience is gained with Day-2 operations.

Prepared by: Jerry Lein

North Dakota Administrative Code

Source: <http://www.state.nd.us/lr/information/acdata/pdf/69-09-02.pdf>

69-09-02-39. Automatic adjustment clauses.

1. As used in this section, the term "automatic adjustment clause" means a tariff provision that provides for increases or decreases, or both, without prior hearing, in rates reflecting increases or decreases, or both, in energy costs incurred by an electric utility.

2. An automatic adjustment clause that does not conform to the principles set out in this section may not be in the public interest. This section contemplates that the filing of a proposed rate tariff that includes a nonconforming automatic adjustment clause may result in suspension of all or part of the tariff.

3. The automatic adjustment clause must be in a form that provides for periodic adjustments per kilowatt-hour of sales equal to the difference between the energy cost per kilowatt-hour of sales in the base period and in the current period in accordance with the following formula:

$$\text{Adjustment Factor} = (F_m - S_m) - (F_b - S_b)$$

For the purposes of this formula: "F_m" is the expense of fossil and nuclear fuel in the current period; "F_b" is the expense of fossil and nuclear fuel in the base period; "S_m" is the kilowatt-hour sales in the current period; and "S_b" is the kilowatt-hour sales in the base period. The energy costs per kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows: Energy costs for actual months 1, 2, 3, and 4 plus unrecovered (or less overrecovered) prior cumulative energy costs divided by kilowatt-hour sales for actual months 1, 2, 3, and 4 equals the energy cost adjustment for month 6.

4. Energy costs (F) are the cost of:

a. Fuel consumed in the utility's own plants, and the utility's share of

fossil and nuclear fuel consumed in jointly owned or leased plants;

b. The actual identifiable fuel costs associated with energy purchased

for reasons other than those identified in subdivision c;

c. The net energy cost of energy purchases, exclusive of capacity or

demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased:

(1) On an economic dispatch basis. Included therein may be such costs as the charges for economic energy purchases

and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy;

(2) From a renewable energy source, including hydropower, wood, windpower, and biomass; and

(3) From a qualifying facility as defined in 18 CFR part 292;

d. Less the cost of fuel recovered through intersystem sales including

the fuel costs related to economy energy sales and other energy

sold on an economic dispatch basis.

5. Sales (S) are all kilowatt-hours sold, excluding intersystem sales. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of:

a. Generation;

b. Purchases;

c. Interchange-in; less

d. Energy associated with pumped storage operations; less

e. Intersystem sales referred to in subdivision d of subsection 4; less

f. Total system losses.

6. The adjustment factor developed according to this procedure must be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

7. The cost of fuel other than nuclear may include only those items listed in Account 151 of the Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel is that in Account 518, to the extent that the cost has not already been included in the cost of other fuel.

8. If the current price of fuels is in litigation or otherwise being collected subject to refund, the utility shall advise the commission and shall keep a separate account of amounts paid that are subject to refund, and shall advise the commission of the final outcome.

9. Notice of change in the adjustment must be filed with the commission prior to billing. The notice must include:

a. Workpapers calculating the adjustment; and

b. To the extent possible, an explanation of market and other factors causing the change.

10. If a particular circumstance prevents the use of a standard or its use would result in an undue burden, the commission may for good cause shown, permit deviation from a standard.

11. The commission may review an automatic adjustment clause at any time to ensure the maximum economies in those operations and purchases which affect the rates to which the clause applies. The commission's review may include an evidentiary hearing. In making this review, the commission may examine and, if appropriate, cause to be audited, the practices of a utility relating to costs subject to an automatic adjustment clause, and may require any filings and reports that may be necessary to carry out the review, including volumes, prices, and contracts for all fuel and electric energy from all sources and a disclosure of any affiliation between the electric utility and the seller of fuel, electric energy, or other items to the utility.

12. Each utility shall cause an independent audit of its automatic adjustment clause to be performed annually. A copy of the auditor's report must be filed annually with the commission.



Public Service Commission

State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E. Wefald
Kevin Cramer

Executive Secretary
Ilona A. Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www.psc.state.nd.us
e-mail ndpsc@state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

March 9, 2005

Bernadeen Brutlaug
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496

Dear Ms. Brutlaug:

On March 9, 2005, the Commission suspended Otter Tail Corporation's Cost of Fuel Adjustment Clause tariff, Case No. PU-05-131.

Sincerely,

Sharon Helbling
Public Utilities Division

sdh

3

PU-05-131

Pages 1

Letter re suspension of tariff

by Public Service Commission

03/09/2005 CC Comm Legal Ilona, Annette, Mike

APPROVED

DATE: 3-9-05
KMF

MOTION

March 9, 2005

**Otter Tail Corporation
Cost of Fuel Adjustment Clause
Tariff**

Case No. PU-05-131

I move the Commission suspend Case No. PU-05-131, Otter Tail Corporation's
Cost of Fuel t Adjustment Clause tariff.

JRL/sdh

2

PU-05-131

Pages 1

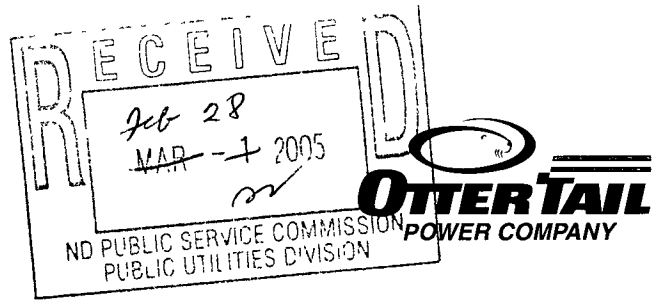
Motion suspending tariff

by Public Service Commission

03/09/2005 CC Comm Legal Ilona Annette Mike

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

February 28, 2005



Ms Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol - 12th Floor
Bismarck, ND 58505

SUBJECT In the Matter of Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY's Application For Fuel Clause Adjustment Revision for MISO Day 2 charges

Dear Ms Jeffcoat-Sacco:

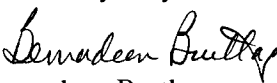
With implementation of the Day 2 Market, Otter Tail Power Company (Otter Tail) is respectfully asking the North Dakota Public Service Commission ("Commission") to affirm that the costs and revenues associated with serving Otter Tail's retail customers through participation in the wholesale electric energy market are appropriate for recovery and pass-through within the fuel clause adjustment ("FCA") As such, Otter Tail requests that the Commission grant the required variances and approve a revised Cost of Energy Adjustment Clause ("COEAC") tariff (designated M-60N)

The date of this filing is February 28, 2005 The proposed effective date, with Commission approval, is on or after April 1, 2005

Enclosed is an original and seven copies of Application including Attachments A (MISO DAY 2 TRANSACTION EXAMPLES), B (Market Settlement Calculations Guide Overview from the MISO Business Practice Manual) and C (Revised Otter Tail Power Company Tariff designated M-60N) Please apply the \$50.00 miscellaneous filing fee from Otter Tail's pre-paid balance for cost of energy filing fees An electronic copy of the Application is being sent via email to you at ijeffcoatsacco@state.nd.us and to Sandi Scott at slscott@state.nd.us

If you have any questions regarding this filing, please contact me at (218) 739-8289 or bbrutlag@otpco.com.

Yours very truly,


Bernadeen Brutlag
Manager, Regulatory Services

Enclosures

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

In the Matter of Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY's
Application For Fuel Clause Adjustment Revision
for MISO Day 2 charges

Case No.

APPLICATION OF OTTER TAIL POWER COMPANY

I. INTRODUCTION

Pursuant to North Dakota Century Code 49-02-11 and North Dakota Administrative Rule 69-09-02-39, Otter Tail Corporation, d/b/a OTTER TAIL POWER COMPANY ("Otter Tail") hereby applies to the North Dakota Public Service Commission for a revision to its Cost of Energy Adjustment Clause for MISO Day 2 charges

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. The existing Fuel Clause Adjustment of Otter Tail is not designed to manage properly the new costs and revenues associated with the MISO Day 2 Market.

With implementation of the Day 2 Market, Otter Tail respectfully petitions the North Dakota Public Service Commission ("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 fuel clause adjustment ("FCA"). As such, Otter Tail requests that the Commission grant the required variances and approve a revised Cost of Energy Adjustment Clause ("COEAC") tariff (designated M-60N)



Public Service Commission
Receipt of Payment

Received 3/1/2005 Check# - Prefile

for

\$50 00

Receipt# 6149

Cost of Energy Adjustment Clause Tariff

Docket # PU-05-131

Deduct from Prefile

Prefile balance \$400. Notify

Otter Tail Corporation
215 S Cascade Street
Fergus Falls MN 56537

dw_psc_receipt

II. DESCRIPTION OF FILING

A. Background

In, Case No. PU-401-01-643 Otter Tail requested that the Commission approve the transfer of functional control of its transmission system (100kV and above) to MISO. By order dated January 31, 2002, the Commission approved the transfer of functional control subject to certain conditions.

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

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")

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 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. Will MISO Day 2 Benefit Ratepayers?

While Otter Tail has been cautiously skeptical regarding the benefits of MISO, our membership in MISO so far has not been much different from our membership in the MidContinent Area Power Pool (MAPP) from a direct revenue and expense perspective. When Otter Tail joined MISO, we did not anticipate there would be a market of the sort now being implemented. MISO has operated for only three years and much effort since the start of operations has been to implement the Day 2 Market. With the implementation of Day 2, Otter Tail extends its cautious skepticism to the benefits of the Day 2 Market. As a small investor-owned utility, Otter Tail is easily impacted by changes in expenses and revenues and is thus very proactive on efficient cost control. Otter Tail has been very active through filings with FERC on issues related the Day 2 Market. Otter Tail's main concern has been to avoid being inappropriately held responsible for the market costs of non-MISO utilities in the Otter Tail Control Area, and at this point it appears we have been successful in those efforts.

With this new paradigm, Otter Tail cannot speculate what the world would have been if FERC had not put us on this road. However, since Otter Tail is on this path, it does not make sense for us to stick our head in the sand and participate only in the most limited sense in the Day 2 Market. Since Otter Tail is committed, we are compelled to participate in the manner that is most effective and efficient for our customers, which necessitates fully utilizing the market tools.

Minnesota Power made a filing with the Minnesota Public Utilities Commission on February 15, 2005 and appropriately stated in its filing, "It is difficult to quantify the benefits of the new market design or the timing of when those benefits will occur. However, it is expected that optimizing generation use through region-wide economic dispatch will evolve as participants adjust to offering generation into the market and that cost-effectively locating generation and transmission will be realized over the longer term."

Otter Tail Company agrees with Minnesota Power's analyses that the following overall benefits may accrue in the Day 2 Markets:

- Energy Pricing - While bilateral energy exchanges in today's wholesale environment have enabled utilities to reduce costs for ratepayers, the centrally dispatched market offered by MISO within an expanded footprint should offer greater liquidity and transparency providing for more efficient pricing than a bilateral market. To the extent that the MISO Day 2 Market provides additional opportunities to reduce fuel costs by making purchases at a price below utilities' incremental cost of production, savings will accrue to utilities' ratepayers.
- Economic Dispatch - utilities currently are required to operate generation units outside of economic merit order to maintain reliability for the entire region. In these circumstances, ratepayers bear the increased fuel costs associated with operating these facilities out of merit order. To the extent that MISO can redispatch generation units within its larger footprint to reduce the magnitude of out of merit order generation, savings will accrue to utility ratepayers.
- Transmission Use - The congestion management system being implemented by MISO in Day 2 will promote more efficient use of limited transmission resources. The existing approach to managing transmission congestion relies on estimating Available Flowgate Capacity (AFC) for purposes of reserving and scheduling available capacity and curtailments

of transmission service under Transmission Loading Relief (TLR). The TLR procedure is a form of rationing that is based on non-economic criteria. Like all physical rationing mechanisms, this system creates inefficiencies compared to a market-based congestion management system provided in MISO Day 2. TLR is time consuming and the actual effects on flows are uncertain. Specifically, the inherently imprecise TLR procedures result in underutilization of transmission capacity, thus limiting additional economic exchanges between utilities and other participants. It is anticipated that there will be considerably less TLR implemented in an LMP market. The transmission reservation system will be used far less in the Day-Ahead and Real-Time Markets but will still be necessary for the long term and generation additions.

- Generation/Transmission Planning - Existing transmission studies cannot provide the market-based information that is so critical to a cost/benefit analysis of large resource additions. Through locational price signals, utilities will be able to determine with greater precision where generation and/or transmission additions can provide the greatest benefit to utilities' ratepayers. Where locational prices are consistently high, additions of generation or transmission will provide the greatest likelihood of lowering costs for all ratepayers.
- Transmission Reliability - MISO's improved ability to redispatch generation over a larger footprint will lessen the potential impacts that transmission outages will have on utilities during periods of adverse operating conditions. As discussed above, the current TLR based congestion management system underutilizes transmission capacity compared to a market-based congestion management system. Therefore, transition to the market-based congestion management system being implemented by MISO in the Day 2 Market will improve reliability for all market participants.
- Market Monitoring - MISO Day 2 will not expose utilities' ratepayers to the extreme market prices that occurred in California during that state's first few years of deregulation. Retail rates are not deregulated in North Dakota and the utilities have retained ownership of their generation assets. Therefore, the COEAC tariff revision proposed in this filing will effectively net MISO Day 2 Market costs and revenues to maintain comparable FCA levels to those prior to the MISO Day 2 Market. Furthermore, MISO will have an Independent Market Monitor ("IMM") whose major function will be to monitor the Day-Ahead and Real-Time Markets to ensure that no gaming of the market exists. That is, that all market bids and offers are kept within the guidelines set out for the start of the Day 2 Market on April 1, 2005.

C. MISO Day 2 Impact on Accounting and Current FCA

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 FCA was developed for operations prior to the Day 2 Market. Otter Tail's FCA complies with rules established by the Commission. 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 FCA. 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 a variance to the FCA Rules to allow for the recovery of the 32 MISO Day 2 charges and revenues. This variance allows a fix to the existing FCA whether or not FERC allows net accounting.

The following simplified table provides an example of current FCA components along with Day 2 Market components. The table also provides the mapping to FERC account of current FCA components and the probable mapping of a sample of Day 2 Market components.

Otter Tail Power Company
Illustration of Impacts of MISO Day 2
Operations/Accounting/FAC

Line	Description of Cost Components	FERC Account*	Current FAC		Proposed FAC
			Current	MISO Day 2	MISO Day 2
1	Fuel Consumed <i>Generated 300 MWh x \$11/MWh</i>	501	3.3	3.3	3.3
2	Purchased Power Energy Consumed <i>Purchased Power - 90 MWh x \$40/MWh</i>	555	3.6		
3	Purchased Steam	503			
4	Released Energy Credits	555			
5	Cost of Buyback Energy Credits	555			
6	Day-Ahead Asset Energy Amount <i>Revenue from sales to Day-ahead markets - 300 MWh x \$34.40/MWh</i>	447		(10.3)	(10.3)
7	Real-Time Asset Energy Amount <i>Revenue from Sales to Real-Time Market</i>	447			
8	Day-Ahead Asset Energy Amount <i>Cost of Purchases to Day-Ahead Market - 390 MWh x \$37.50/MWh</i>	555		14.63	14.63
9	Real-Time Asset Energy Amount <i>Cost of Purchases of Real-Time Market</i>	555			
10	Financial Transmission Rights Hourly Allocation Amount	456		(0.390)	(0.390)
11	Real-Time Distribution of Losses Amount <i>Marginal Loss Compensation</i>	456		(0.390)	(0.390)
12	Financial Transmission Rights Market Administration Amount <i>Schedule 16 - 0.053/MWh x 300 MWh</i>	565		0.016	0.016
13	Day-Ahead Market Administration Amount <i>Schedule 17 - \$0.081/MWh x 690 MWh</i>	565		0.042	0.042
14	Less Costs Recovered via Intersystem Sales <i>MWh</i>		-	(3.3)	-
15	Net Cost of Power <i>Purchased Power MWh</i>		6.9	14.63	6.883

MWh Sales of Electricity (net of losses)		0.32	0.32	0.32
Average Cost (\$/MWh)		21.56	45.70	21.51
FAC base (\$/MWh)		16.473	16.473	16.473
FAC (\$/MWh)		5.09	29.23	5.04

Items in Gray not included in calculation of FAC

*Subject to FERC Rulemaking

The table on page 9 calculates a fuel adjustment under the existing FCA 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 FCA includes fuel and purchased energy for retail customers.

The application of our existing FCA rules to the MISO Day 2 Market results 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 variance in FCA rules to include offsetting revenues (shaded items), the FCA would be overstated.

Otter Tail's proposed FCA 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 FCA and current market. The proposed revision requires a variance to the FCA rules to allow inclusion of amounts recorded in accounts other than Fuel (501) and Purchased Power (555).

An alternative solution is to order a variance to the FERC accounting rules to net all costs and revenues associated with MISO Day 2 transactions to serve retail customers in account 555. Otter Tail urges the Commission not to choose this alternative. 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. Otter Tail operates in three states and FERC. It is unlikely all four jurisdictions would order identical accounting variances of the nature just described. Otter Tail calculates its cost of energy at a system level. Maintaining a subset of accounting records for one jurisdiction is impractical and has greater potential for errors in calculation of the FCA in all jurisdictions.

Attachment A provides a series of examples of how various market scenarios would influence the FCA.

III. REQUESTED FCA REVISION AND IMPLEMENTATION

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

Presently, Otter Tail and other North Dakota electric utilities recover the cost of purchased energy, fuel, delivered losses, and congestion (in the form of redispatched units) through the FCA (Otter Tail estimates approximately 56,000 of its North Dakota customers are subject to its Cost of Energy Adjustment Clause). 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 below, 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 COEAC 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 COEAC tariff also anticipates that the costs and revenues to fulfill its load serving obligation may evolve as wholesale electric energy markets evolve. The revised COEAC tariff, M-60N, provided as Attachment C, adds a new component inserted as 4. (indicated by the N in the right hand margin of the attached tariff sheet to the definition of Fuel Cost as follows:

- 4 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 4. is renumbered as item 5. as noted by the C right hand margin the attached tariff sheet. As stated previously in this filing, Otter Tail strongly prefers a

variance to the fuel clause rules to allow the use of the accounts shown in the table on page 9, to allow flow-through of revenues and costs, rather than an accounting variance which flows all the costs and revenues through account 555. Otter Tail's multi-jurisdictional operations make an accounting variance in one jurisdiction impractical and administratively burdensome. It is unlikely all four jurisdictions, particularly FERC, would allow identical accounting variances. To effectuate the FCA rule variance, 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 COEAC tariff. These costs and accounts are used in the table on page 9 of 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 the table), 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 COEAC tariff to be effective with the implementation of MISO's TEMT. The proposed revision to the COEAC tariff is not an expansion of the scope of the FCA, rather, the revised COEAC 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 COEAC tariff, Otter Tail will continue to use the same principles for allocating native and intersystem wholesale costs ensuring that native load has first call on least-cost generation resources. Otter Tail believes that its proposal to amend the COEAC tariff will result in rate recovery of the overall costs for fuel and energy comparable to the costs contemplated to be recovered by the FCA 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

Xcel Energy, in its Minnesota petition (Docket No. E-002/M-04-1970) filed December 14, 2004, discussed the appropriateness of deferred accounting for Schedules 16 and 17 and uplift charges. MISO will be assessing these non-transaction specific charges to all Day 2 market participants to cover the costs of the new market. Otter Tail

seeks FCA 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 FCA.

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 FCA. These new charges are required in the procurement of energy for Otter Tail customers and the costs are assessed primarily on an energy basis. Deferral of these Day 2 Market costs could create a problem in the future of matching today's costs with future customers.

C. Settlements

The settlement process will provide the detail charges for FCA 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. Required Variance

While Otter Tail believes that its proposal for treating Day 2 Market costs is consistent with the purpose of the FCA and should be affirmed, Otter Tail recognizes that the specific calculations established in ND Rule 69-09-02-39 did not anticipate all of the charges provided by the TEMT or provide for the pass-through of associated revenues. Consequently, to approve the revised COEAC tariff, Otter Tail respectfully requests a variance to ND Rule 69-09-02-39 (“FCA Rule”).

ND Rule 69-09-02-39 paragraph 10 allows the Commission to vary the FCA rule “If a particular circumstance prevents the use of a standard or its use would result in an undue burden, the commission may for good cause shown, permit deviation from a standard.”

1. Enforcement of the rule would result in an undue burden on the applicant or others affected by the rule

The Commission’s current FCA Rules were adopted long before the development of the Day 2 Market. As such, the FCA Rules do not specifically accommodate the operation of the market or all of its various components.

Absent the requested variance, both Otter Tail and its customers will face an excessive burden. If the FCA Rules are not varied, the mechanical application of the current FCA Rules and COEAC tariff would cause customers to pay the cost of LMP purchases from the market and not the actual cost of production, without the expected positive value of FTRs used to hedge the congestion costs associated with transactions from its generation. On the other hand, if the FCA Rules are interpreted to exclude recovery of new components of the Day 2 Market, such as congestion and marginal loss costs, Otter Tail may not be fully compensated for the costs incurred in providing energy delivered to its customers. Granting the requested variances retains, to the extent possible, the current balance provided for by Otter Tail regulation and the FCA.

2. *There is good cause to permit the deviation by allowing a variance.*

The public interest will be served by adopting a proposal that most closely achieves the current balance between Otter Tail and customers provided for in the existing FCA mechanism. The anomalous results that could occur for either customers or Otter Tail would be inconsistent with the purpose of the existing FCA mechanism, which treats both fairly.

All of the costs and revenues sought to be included in the FCA can properly be viewed as federally regulated wholesale rates for energy delivered through interstate facilities. MISO is a regional transmission organization ("RTO") regulated by FERC, and the charges under the TEMT are FERC-regulated wholesale rates for energy delivered through interstate electric transmission facilities under the functional control of and subject to the tariff of MISO

Because the conditions for granting a variance have been met, the Commission should approve the requested variance to the FCA Rules.

E. Additional Reporting Requirements

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

F. Implementation Prior to Final Commission Decision

Otter Tail requests authority to implement our proposed COECA tariff effective with the start of the MISO Day 2 Market on April 1, 2005. As a practical matter, the calculation of our FCA will not reflect Day 2 transactions until June, which will be applied to July retail electric service bills. This effective date insures the netting of MISO Day 2 costs and revenues starting April 1. Otter Tail would refund to customers any excess FCA collections during the period from April 1, 2005 to the implementation

date set in the Commission's order. Any refund amount would include interest and use the FCA as the refund mechanism, to be completed within 120 days of the Final Commission Order.

IV. GENERAL FILING INFORMATION.

Pursuant to N.D. Admin. Rule 69-02-02-04, Otter Tail provides the following general information.

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

Otter Tail Power Company
215 South Cascade Street
P O Box 496
Fergus Falls, MN 56538-0496
(218) 739-8200

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

Bruce Gerhardson
Associate General Counsel
Otter Tail Corporation
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
218) 998-7108

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

This application for a revision to its Cost of Energy Adjustment Clause for MISO Day 2 charges is being filed on February 28, 2005 and Otter Tail requests approval on or before April 1, 2005.

D. Statute Controlling Schedule for Processing the Filing.

North Dakota Statutes and related rules do not establish an explicit deadline for Commission action. Otter Tail requests an expedited and informal proceeding, including any variances, which may be necessary pursuant to N.D. Admin. Rule 69-02-01-11.

E. Title of Utility Employee Responsible for Filing.

Bernadeen Brutlag
Manager, Regulatory Services
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8289

V. CONCLUSION

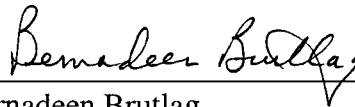
The MISO Day 2 Market will change the way Otter Tail dispatches its generation units and purchases energy for delivery to serve Otter Tail's retail customers. Otter Tail's existing FCA cannot properly handle the new MISO Day 2 Market costs and revenues. This new market is scheduled to begin on April 1, 2005

Otter Tail requests Commission affirmation that the costs and revenues associated with serving its retail customers through the participation in this new wholesale electric energy market are appropriate for recovery and pass-through via the FCA. Otter Tail respectfully requests that the Commission:

- grant the required variance to ND Rule 69-09-02-39 and;
- approve the proposed COECA tariff revision effective on the start of the MISO Day 2 Market.

February 28, 2005

Respectfully submitted,



Bernadeen Brutlag
Manager, Regulatory Services
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, MN 56538-0496
(218) 739-8289

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 3⁴ **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 is 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.

Scenario 5
Real-Time Purchase With Load Above Forecast

Otter Tail native load is greater than settled in the Day Ahead Market for 3 hours and we purchase 20 MWHs real time at a price of \$100/MWH (which includes an energy price of \$80/MWH and a congestion price of \$20/MWH). An equal amount of generation from Solway (20 MWHs) was picked up in Real Time at a price of \$80/MWH. The cost of fuel for the Solway natural gas unit during real time was \$50/MWH.

Resulting Charges:

- Otter Tail pays an LMP cost for energy of \$100/MWH (for 20 MW*3 hours) to the Midwest ISO
- The Company incurs fuel costs of \$50/MWH.
- Otter Tail receives a payment of \$80/MWH from the Midwest ISO for its generation.
- FTRs are not available to hedge congestion costs in the Real Time market.

Alternative FCA Outcomes for Customers

- Today: Customers are charged \$50/MWH for the fuel cost.
- Day 2 with No Change in FCA Tariff: Customers are charged \$100/MWH for 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 \$70.00/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 and Carve-Out Grandfathered Agreement Transaction congestion costs for 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

ATTACHMENT C

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota
ELECTRIC RATE SCHEDULE

Volume I, Sheet 98

Rate Designation M-60N, Page 1 of 1
Tenth Revision

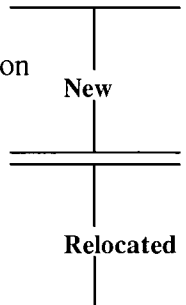
COST OF ENERGY ADJUSTMENT CLAUSE

There shall be added to or deducted from the monthly bill the amount per kilowatthour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 1.6473¢ per kilowatthour. The average cost of energy per kilowatthour for the current period shall be calculated from data covering actual costs from the most recent four month period as follows:

Energy costs from actual months 1, 2, 3, 4 and 5 plus unrecovered (or less over recovered) prior cumulative energy costs divided by the associated energy (reduced for average system losses) associated with retail sales for actual months 1, 2, 3, 4 and 5 equals the cost of energy adjustment for month 6.

The applicable adjustment will be applied effective on any billing dated on or after the first day of each calendar month. The average cost of energy shall be determined as follows:

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants. Energy from the Company's hydro generating plants shall be included at zero cost.
2. The energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of capacity or demand charges
3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in 2 above.
4. 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
5. Less the fuel related costs recovered through intersystem sales.



NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Approved: _____, 2005
Case No. PU-___-___-___

RATES EFFECTIVE with bills rendered
on and after April 1, 2005, in ND

APPROVED: Bernadeen Brutlag
Manager, Regulatory Services

DU-05-131, PU-05-135, PD-05-147

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits.

1 Article Addressed to:

*Bernstein Brulley
Otter Tail Corporation
215 Cascade St
Fergus Falls MN 56504*

2 Article Number

(Transfer from service label)

7003 2260 0001 3517 9749

PS Form 3811, February 2004

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature

X *Kress Becke* Agent Addressee

B Received by (Printed Name)

C Date of Delivery

APR 11 2005

D Is delivery address different from item 1? Yes
If YES, enter delivery address below No

3 Service Type

- Certified Mail Express Mail
- Registered Return Receipt for Merchandise
- Insured Mail C O D.

4 Restricted Delivery? (Extra Fee)

Yes

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to

*Thomas D. Kelsch
Counsel for North Dakota
OTP Large Industrial
Group
PO Box 1266
Mandan, ND 58534-1266*

2 Article Number

(Transfer from servi

7007 0710 0001 5988 1620

PS Form 3811, February 2004

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature

X *Keiner* Agent Addressee

B Received by (Printed Name)

C Date of Delivery

Keiner *8-14-07*

D Is delivery address different from item 1? Yes
If YES, enter delivery address below No

3 Service Type

- Certified Mail Express Mail
- Registered Return Receipt for Merchandise
- Insured Mail C O D

4 Restricted Delivery? (Extra Fee)

Yes

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to

*Bruce Gerhardson
Associated General Counsel
Otter Tail Corporation
215 Cascade St
Fergus Falls MN 56504*

COMPLETE THIS SECTION ON DELIVERY

A Signature

X *David Bostele* Agent Addressee

B Received by (Printed Name)

C Date of Delivery

David Bostele *8/3/07*

D Is delivery address different from item 1? Yes
If YES, enter delivery address below No

3 Service Type

- Certified Mail Express Mail
- Registered Return Receipt for Merchandise
- Insured Mail C O D

4 Restricted Delivery? (Extra Fee)

Yes

P4-05-131; P4-05-135, P4-05-147

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 		A. Signature <input checked="" type="checkbox"/> <i>[Signature]</i> <input type="checkbox"/> Agent <input type="checkbox"/> Addressee	
1. Article Addressed to		B. Received by (Printed Name)	C. Date of Delivery
Don Deliquant 1000 1st St PO Box 2707 Fargo ND 58202-0207		<i>Michelle Kray</i>	<i>April 11 2005</i>
		D. Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below. <input type="checkbox"/> No	
		3. Service Type	
		<input type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D	
		4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2. Article Number (Transfer from service label)		7003 2260 0001 3517 9763	

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

P4-05-131, P4-05-135, P4-05-147

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 		A. Signature <input checked="" type="checkbox"/> <i>[Signature]</i> <input type="checkbox"/> Agent <input type="checkbox"/> Addressee	
1. Article Addressed to		B. Received by (Printed Name)	C. Date of Delivery
Don Dail Mission Dist. Utilities Co 4601 27th St Bismarck ND 58501		<i>AC Scriber</i>	<i>4/8/05</i>
		D. Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below. <input type="checkbox"/> No	
		3. Service Type	
		<input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D	
		4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2. Article Number (Transfer from service label)		7003 2260 0001 3517 9756	

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

P4-05-131

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits. 		A. Signature <input checked="" type="checkbox"/> <i>[Signature]</i> <input type="checkbox"/> Agent <input type="checkbox"/> Addressee	
1. Article Addressed to		B. Received by (Printed Name)	C. Date of Delivery
Thomas D Kelsch Counsel for North Dakota OTP Large Industrial Energy Group PO Box 1266 Mandan ND 58554-1266		<i>L Reiner</i>	<i>1-25-07</i>
		D. Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below. <input type="checkbox"/> No	
		3. Service Type	
		<input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D	
		4. Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2. Article Number		7003 2260 0001 3517 2411	

PU-05-131

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to
 Bernadeen Brutlay
 Manager - Regulatory Services
 Otter Tail Corporation
 215 S. Cascade St.
 Fergus Falls, MN 56538-0496

2. Article Number (Transfer from service label) 7007 0710 0001 5988 1644

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature Agent Addressee
 X *[Signature]*
 B Received by (Printed Name) Dorel Casanova C Date of Delivery 8/13/07
 D Is delivery address different from item 1? Yes No
 If YES, enter delivery address below

3 Service Type
 Certified Mail Express Mail
 Registered Return Receipt for Merchandise
 Insured Mail C O D
 4 Restricted Delivery? (Extra Fee) Yes

PU-05-131

SENDER: COMPLETE THIS SECTION

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- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to
 BERNADEEN BRUTLAY
 OTTER TAIL CORPORATION
 215 S CASCADE ST
 FERGUS FALLS MN 56538-0496

2 Article Number (Transfer from service label) 7006 0100 0003 7161 2804

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature Agent Addressee
 X *[Signature]*
 B Received by (Printed Name) C Date of Delivery JAN 26 2007
 D Is delivery address different from item 1? Yes No
 If YES, enter delivery address below

3 Service Type
 Certified Mail Express Mail
 Registered Return Receipt for Merchandise
 Insured Mail C O D
 4 Restricted Delivery? (Extra Fee) Yes

PU-05-131

SENDER: COMPLETE THIS SECTION

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to PU-05-131
 DANIEL S KUNTZ
 Associate General Counsel
 MONTANA DAKOTA UTILITIES
 PO Box 5650
 1200 West Century Ave
 Bismarck ND 58506-5650

2. Article Number (Transfer from service label) 7006 0100 0003 7161 2927

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature Agent Addressee
 X *[Signature]*
 B Received by (Printed Name) AL SODR C Date of Delivery 3 22 07
 D Is delivery address different from item 1? Yes No
 If YES, enter delivery address below

3 Service Type
 Certified Mail Express Mail
 Registered Return Receipt for Merchandise
 Insured Mail C O D
 4 Restricted Delivery? (Extra Fee) Yes

RU-05-131

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to

DONALD R BALL
 Vice President-Regulatory Affairs
 MONTANA-DAKOTA Utilities Co
 400 N 4 ST
 BISMARCK ND 58501

2 Article Number

(Transfer from service label)

7006 0100 0003 7161 2880


PS Form 3811, February 2004

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature

X 

Agent

Addressee

B Received by (Printed Name)

DL Ball

C Date of Delivery

3-22-07

D Is delivery address different from item 1? If YES, enter delivery address below

Yes

No

3 Service Type

Certified Mail

Express Mail

Registered

Return Receipt for Merchandise

Insured Mail

C O D

4 Restricted Delivery? (Extra Fee)

Yes

RU-05-131

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to

THOMAS D Kelsch
 Counsel for North Dakota
 OTP Large Industrial Energy Group
 PO Box 1266
 MANDAN ND 58554-7266

2 Article Number

(Transfer from service label)

7006 0100 0003 7161 2903

PS Form 3811, February 2004

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature

X 

Agent

Addressee

B Received by (Printed Name)

T D Kelsch

C Date of Delivery

3-22-07

D Is delivery address different from item 1? If YES, enter delivery address below

Yes

No

3 Service Type

Certified Mail

Express Mail

Registered

Return Receipt for Merchandise

Insured Mail

C O D

4 Restricted Delivery? (Extra Fee)

Yes

RU-05-131

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired
- Print your name and address on the reverse so that we can return the card to you
- Attach this card to the back of the mailpiece, or on the front if space permits

1 Article Addressed to

Megan Hertzer
 Assistant General Counsel
 414 Nicollet Mall 5th Flr
 Minneapolis MN 55401

2 Article Number

(Transfer from service label)

7006 0100 0003 7161 2934

PS Form 3811, February 2004

Domestic Return Receipt

102595-02-M-1540

COMPLETE THIS SECTION ON DELIVERY

A Signature

X 

Agent

Addressee

B Received by (Printed Name)

D Is delivery address different from item 1? If YES, enter delivery address below

Yes

No

3 Service Type

Certified Mail

Express Mail

Registered

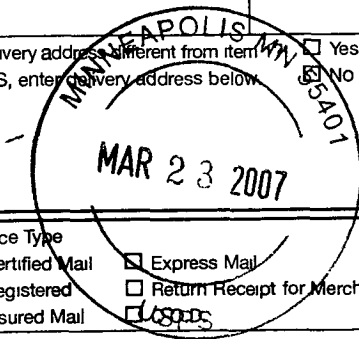
Return Receipt for Merchandise

Insured Mail

C O D

4 Restricted Delivery? (Extra Fee)

Yes



DU-05-131

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired Print your name and address on the reverse so that we can return the card to you Attach this card to the back of the mailpiece, or on the front if space permits 		A Signature <input checked="" type="checkbox"/> <i>Mike Holden</i> <input type="checkbox"/> Agent <input type="checkbox"/> Addressee B Received by (Printed Name) <input type="checkbox"/> C Date of Delivery <i>Mike Holden</i> <input type="checkbox"/> MAR 23 2007 D Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below <input type="checkbox"/> No	
1 Article Addressed to <i>DAVE Sederquist</i> <i>Senior Consultant</i> <i>Regulatory + Finance</i> <i>Xcel Energy</i> <i>PO Box 2141</i> <i>KARGO MN 58208-2141</i>		3 Service Type <input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D 4 Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2 Article Number (Transfer from service label) 7006 0100 0003 7161 2897			
PS Form 3811, February 2004		Domestic Return Receipt 102595-02-M-1540	

DU-05-131

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired. Print your name and address on the reverse so that we can return the card to you. Attach this card to the back of the mailpiece, or on the front if space permits 		A Signature <input checked="" type="checkbox"/> <i>Russ Berke</i> <input checked="" type="checkbox"/> Agent <input type="checkbox"/> Addressee B Received by (Printed Name) <input type="checkbox"/> C Date of Delivery <input type="checkbox"/> 3-23-07 D Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below <input type="checkbox"/> No	
1 Article Addressed to <i>Bernadene Bruntlag</i> <i>Manager - Regulatory Services</i> <i>Otter Tail Corporation</i> <i>215 S Cascade St</i> <i>Fergus Falls MN 56538-0496</i>		3 Service Type <input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D 4 Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2 Article Number (Transfer from service label) 7005 3110 0003 6265 0159			
PS Form 3811, February 2004		Domestic Return Receipt 102595-02-M-1540	

DU-05-131

SENDER: COMPLETE THIS SECTION		COMPLETE THIS SECTION ON DELIVERY	
<ul style="list-style-type: none"> Complete items 1, 2, and 3 Also complete item 4 if Restricted Delivery is desired Print your name and address on the reverse so that we can return the card to you Attach this card to the back of the mailpiece, or on the front if space permits 		A Signature <input checked="" type="checkbox"/> <i>Russ Berke</i> <input checked="" type="checkbox"/> Agent <input type="checkbox"/> Addressee B Received by (Printed Name) <input type="checkbox"/> C Date of Delivery <input type="checkbox"/> 3-23-07 D Is delivery address different from item 1? <input type="checkbox"/> Yes If YES, enter delivery address below <input type="checkbox"/> No	
1 Article Addressed to <i>Bruce Gerhardson</i> <i>Associate General Counsel</i> <i>Otter Tail Corporation</i> <i>215 S Cascade St</i> <i>Fergus Falls MN 56538-0496</i>		3 Service Type <input checked="" type="checkbox"/> Certified Mail <input type="checkbox"/> Express Mail <input type="checkbox"/> Registered <input type="checkbox"/> Return Receipt for Merchandise <input type="checkbox"/> Insured Mail <input type="checkbox"/> C O D 4 Restricted Delivery? (Extra Fee) <input type="checkbox"/> Yes	
2 Article Number (Transfer from service label) 7006 0100 0003 7161 2910			
PS Form 3811, February 2004		Domestic Return Receipt 102595-02-M-1540	