

# DIVIDER

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

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## DESCRIPTION

PU-05-147

Northern States Power Company  
Cost of Fuel Adjustment Clause  
Tariff

Filed 3/4/2005

Closed 7/13/2005

05



Public Service Commission  
State of North Dakota

COMMISSIONERS

Susan E Wefald, President  
Kevin Cramer  
Tony Clark

Executive Director  
Illona 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

February 28, 2008

Megan J. Hertzler  
Assistant General Counsel  
Xcel Energy Services Inc.  
414 Nicollet Mall, 5<sup>th</sup> Fl.  
Minneapolis, MN 55401

Douglas A. Bahr  
Division Director  
Office of the Attorney General  
600 E. Boulevard Ave. Dept 125  
Bismarck, ND 58505

Re: Case No. PU-07-776, NSP Electric Rate Increase Application

Dear Ms. Hertzler and Mr. Bahr:

The purpose of this letter is to request that you investigate and address the following issues:

1. Whether the terms, conditions and enforcement provisions for interruptible services are cost based and reasonable especially given changes occurring in the wholesale industry, including the expected discontinuance of the Mid-continent Area Power Pool financial obligation for planning reserve capacity and implementation of the Midwest ISO markets and Open Access Transmission Tariff (OATT) Module E resource adequacy requirements.
2. What recovery procedures should be approved for Midwest ISO energy market costs and should any amounts already recovered be refunded? Interim procedures for recovery through NSP's Fuel Cost Adjustment were approved subject to refund by the Commission in Case No. PU-05-147. Since then, the FERC ordered that MISO administrative cost adders under OATT schedules 16 and 17 are no longer eligible for recording as a cost of fuel and purchased energy in FERC Account 555. MDU (Case No. PU-06-447) and Otter Tail (Case

12	<u>PU-05-147</u>	Pages 2
50	PU-07-776	Pages 2

Letter Requesting Investigation

by Public Service Commission by Lem  
02/28/2008

No. PU-05-131) have refunded schedule 16 and 17 administrative charges and are no longer recovering those costs through fuel cost adjustments.

Sincerely,

A handwritten signature in black ink, appearing to read "Jerry Lein". The signature is fluid and cursive, with the first name "Jerry" and last name "Lein" clearly distinguishable.

Jerry Lein  
Public Utilities Analyst  
Commission Advisory Staff

cc Kent Larson  
Dave Sederquist  
Mike Diller  
Pat Fahn  
Commissioner Susan Wefald  
Commissioner Kevin Cramer  
Commissioner Tony Clark



# Public Service Commission

## State of North Dakota

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### 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](http://www.psc.state.nd.us)  
e-mail [ndpsc@state.nd.us](mailto:ndpsc@state.nd.us)  
TDD 800-366-6888  
Fax 701-328-2410  
Phone 701-328-2400

July 13, 2005

Dave Sederequist  
Xcel Energy  
P O Box 2747  
Fargo ND 58208-2747

Dear Mr. Sederquist:

On July 13, 2005, the Commission approved Northern States Power Company's cost of fuel adjustment clause, Case No. PU-05-147

Sincerely,

A handwritten signature in black ink, appearing to read "Sharon Helbling".

Sharon Helbling  
Public Utilities Division

sdh

Enclosure

**MOTION**

**July 13, 2005**

**APPROVED**

DATE. 7-13-05  
KME

**Northern States Power Company  
Cost of Fuel Adjustment Clause  
Tariff**

**Case No. PU-05-147**

I move the Commission approve Northern States Power Company's Cost of Fuel Adjustment Clause tariff, Case No. PU-05-147.

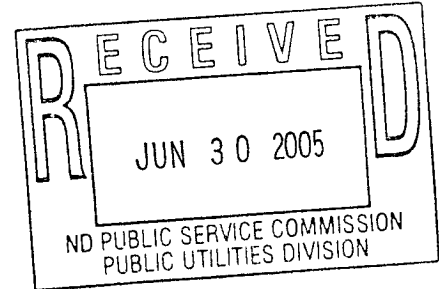
JRL/sdh



2302 Great Northern Drive  
P O Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632  
dave.sederquist@xcelenergy.com

June 29, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept 408  
600 East Boulevard  
Bismarck, ND 58505-0480



RE: MISO DAY 2 - FUEL CLAUSE TARIFF COMPLIANCE  
CASE NO PU-400-05-147

Dear Ms Jeffcoat-Sacco

Enclosed are an original and seven copies of a compliance interim fuel clause rate tariff related to the recovery of MISO Day 2 net costs as ordered by the Commission on April 6, 2005

On March 4, 2005 the Company filed a petition for changes to Fuel Clause Rider No 1 to accommodate MISO Day 2 activities On April 6 the Commission issued an order allowing interim accounting treatment and recovery of net costs of energy purchased through the MISO Day 2 energy market to service native load

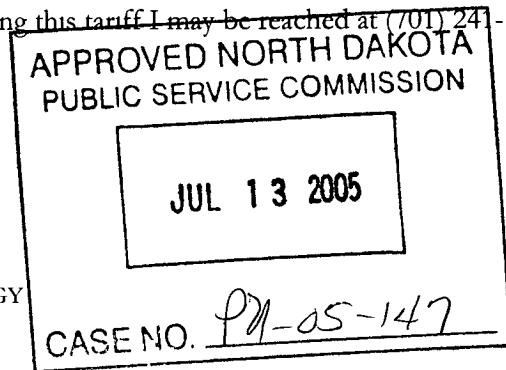
Also, in its April 6<sup>th</sup> order, the Commission requested Northern States Power Co. d/b/a Xcel Energy, Ottertail Power Company, and Montana-Dakota Utilities to refile Fuel Clause tariffs with standard language as it relates to MISO Day 2 recovery On June 14, the Company filed a tariff to reflect that revision, but the language was placed incorrectly in the tariff, leaving the accounting treatment unclear The attached tariff (both normal and red-line versions) has the language in the appropriate place:

**North Dakota Electric Rate: Sheet No. E 76.2, revision 15**

If you have any other questions or comments regarding this tariff I may be reached at (701) 241-8632

Sincerely,

*David H Sederquist*  
DAVID H SEDERQUIST  
SR. CONSULTANT, REGULATION & FINANCE  
NORTHERN STATES POWER CO D/B/A XCEL ENERGY



Enclosures

FUEL CLAUSE RIDER NO. 1

There shall be added to or deducted from the net monthly bill \$0 00001 per kilowatt-hour for each \$0 00001 increase above or decrease below \$0 01092 in the fuel cost per kilowatt-hour sales

The fuel cost shall be the sum of the following for the most recent four month period plus unrecovered (or less over-recovered) prior cumulative energy costs

- 1 The cost of fossil, nuclear, and other fuels, including but not limited to biomass, wood, and refuse derived fuel (RDF), consumed in the Company's generating stations as recorded in Accounts 151 and 518
- 2 The net energy cost of energy purchases, including gains, losses, premium payments, and transaction costs related to financial instruments and linked transactions used to mitigate price volatility, as recorded in Account 555 exclusive of capacity or demand charges including but not limited to
  - a Energy purchased on an economic dispatch basis, including 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,
  - b Energy purchased from a renewable energy source, including but not limited to hydropower, wood, windpower, and biomass,
  - c Energy purchased from a qualifying facility as defined in 18 C F R Part 292
  - d Net costs linked to the Company'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, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above
- 4 Less the fuel related costs recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis

APPROVED NORTH DAKOTA  
PUBLIC SERVICE COMMISSION

Filing Date: 06-28-05

By: K. T. Larson  
Vice President of Jurisdictional Relations

Effective:

JUL 13 2005

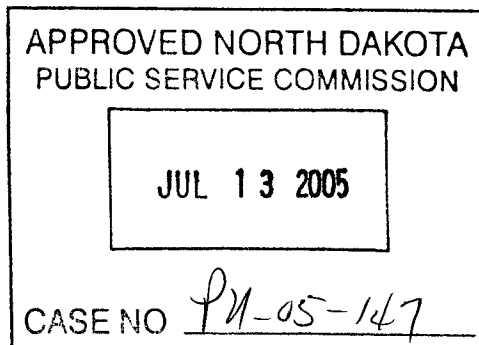
NDPSC Case No: PU-400-05-147

Order Date:

CASE NO. PU-05-147

FUEL CLAUSE RIDER NO. 1

The kilowatt-hour sales shall be all kilowatt-hours sold excluding intersystem sales for the most recent four month period



Filing Date: 06-28-05

By: K. T. Larson  
Vice President of Jurisdictional Relations

Effective:

NDPSC Case No: PU-400-05-147

Order Date:

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  - a Energy purchased ~~O~~ on an economic dispatch basis, including 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,
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  - d Net costs linked to the Company'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 Net Costs or revenues linked to the Company'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~~

Filing Date: 06-28-05

By: K. T. Larson  
Vice President of Jurisdictional Relations

Effective:

NDPSC Case No: PU-400-05-147

Order Date:

**FUEL CLAUSE RIDER NO. 1**

4-3 The actual identifiable fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above

5-4 Less the fuel related costs recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis

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Filing Date: 06-28-05

By: K. T. Larson  
Vice President of Jurisdictional Relations

Effective:

NDPSC Case No: PU-400-05-147

Order Date:



2302 Great Northern Drive  
P O Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632  
dave.sederquist@xcelenergy.com

June 16, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480

RE: MISO DAY 2 - FUEL CLAUSE TARIFF COMPLIANCE  
CASE NO. PU-400-05-147

Dear Ms. Jeffcoat-Sacco:

Enclosed are an original and one copy of a compliance interim fuel clause rate tariff related to the recovery of MISO Day 2 net costs as ordered by the Commission on April 6, 2005.

On March 4, 2005, the Company filed a petition for changes to Fuel Clause Rider No. 1 to accommodate MISO Day 2 activities. On April 6 the Commission issued an order allowing interim accounting treatment and recovery of net costs of energy purchased through the MISO Day 2 energy market to service native load. The attached tariff reflects that order.

**North Dakota Electric Rate: Sheet No. E 76.2, revision 14**

Also, in its April 6<sup>th</sup> order, the Commission requested Northern States Power Co d/b/a Xcel Energy, Ottertal Power Company, and Montana-Dakota Utilities to refile Fuel Clause tariffs with standard language as it relates to MISO Day 2 recovery. The attached tariff (both normal and red-line versions) reflects this revision:

**North Dakota Electric Rate: Sheet No. E 76.2, revision 15**

It was recently discovered that this tariff had not been filed by the Commission's requested date of May 15, as previously thought. The Company regrets this oversight and apologizes for any inconvenience this may have caused.

If you have any other questions or comments regarding this tariff I may be reached at (701) 241-8632.

Sincerely,

DAVID H. SEDERQUIST  
SR CONSULTANT, REGULATION & FINANCE  
NORTHERN STATES POWER CO. D/B/A XCEL ENERGY

FUEL CLAUSE RIDER NO. 1

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Filing Date: 06-13-05

By: K. T. Larson  
Vice President of Jurisdictional Relations

Effective:

NDPSC Case No: PU-400-05-147

Order Date:

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**Filing Date: 06-13-05**

**By: K. T. Larson  
Vice President of Jurisdictional Relations**

**Effective:**

**NDPSC Case No: PU-400-05-147**

**Order Date:**

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 4<sup>th</sup> 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 4<sup>th</sup> 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**.

SEAL



*Sharon Helbling*  
\_\_\_\_\_

*Sandra L Scott*  
\_\_\_\_\_  
Notary Public

APPROVED

DATE 4-6-05  
KMF

**MOTION**

**April 6, 2005**

**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

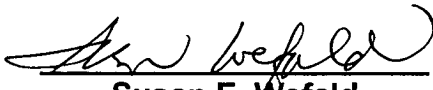
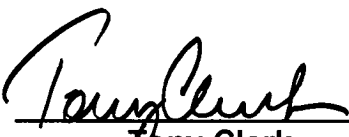
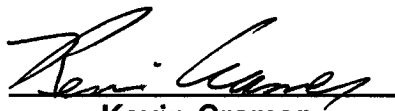
the net costs of energy, including TEMT Schedules 16 and 17 charges and FERC approved uplift charges, purchased through the Midwest ISO Day 2 energy market to serve native load. The Commission further finds that amounts collected under this interim treatment should be subject to refund with interest 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 1<sup>st</sup> 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 23<sup>rd</sup>.

**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 24<sup>th</sup> 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<sub>m</sub>" is the expense of fossil and nuclear fuel in the current period; "F<sub>b</sub>" is the expense of fossil and nuclear fuel in the base period; "S<sub>m</sub>" is the kilowatt-hour sales in the current period; and "S<sub>b</sub>" 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

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### 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

March 23, 2005

Dave Sederquist  
Xcel Energy  
P O Box 2747  
Fargo ND 58108-2747

Dear Mr. Sederquist:

On March 23, 2005, the Commission suspended Northern States Power Company's Cost of Fuel Adjustment Clause tariff, Case No. PU-05-147.

Sincerely,

Sharon Helbling  
Public Utilities Division

sdh

**APPROVED**

DATE 3-23-05  
KMF

**MOTION**

**March 23, 2005**

**Northern States Power Company  
Cost of Fuel Adjustment Clause  
Tariff**

**Case No. PU-05-147**

I move the Commission suspend Northern States Power Company's Cost of Fuel Adjustment Clause tariff, Case No. PU-05-147.

JRL/sdh



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Public Service Commission  
Receipt of Payment

Received 3/8/2005 Check# - Prefile for \$50 00  
Subject Cost of Fuel Adjustment Clause Tariff

Receipt# 6160

**Docket # PU-05-147**

**Deduct from Prefile**

**Prefile balance \$. Notify Mr. David Sparby**

Mr David Sparby  
Northern States Power Company  
414 Nicollet Mall  
Minneapolis MN 55401

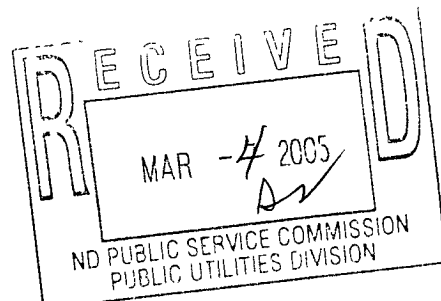
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2302 Great Northern Drive  
P O Box 2747  
Fargo, ND 58108-2747  
(701) 241-8632  
dave.sederquist@xcelenergy.com

March 4, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480



Re: Northern States Power Company d/b/ Xcel Energy  
Application for Fuel Clause Adjustment Recovery of MISO Day 2 Net Costs and Revenues

Dear Ms. Jeffcoat-Sacco:

Northern States Power Company d/b/a/Xcel Energy herewith requests North Dakota Public Service Commission confirmation that the net costs and revenues associated with serving the Company's retail electric customers in North Dakota through participation in the Midwest ISO's "Day 2" wholesale electric energy market are appropriate for inclusion in the Company's Fuel Clause Adjustment (FCA) Rider as set forth in its Electric Rate Book and the Commission's existing Automatic Adjustment Clause administrative rules (Chapter 69-09-02-39). The Company also requests the Commission approve certain proposed revisions to the FCA tariff rider effective April 1, 2005, the planned implementation date for the Day 2 Market.

An original and seven copies of the application are enclosed. Attachment A to the filing lists a number of example Day 2 Market transactions, and Attachment B is the revised FCA Rider tariff. An electronic copy of this filing has been sent to the Commission as well.

Let me know if you have any other questions or comments regarding this significant project.

Sincerely,

David H. Sederquist  
Sr. Consultant, Regulation & Finance  
Northern States Power Co. d/b/a Xcel Energy

Enclosures

STATE OF NORTH DAKOTA  
BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Anthony T. Clark  
Susan E. Wefald  
Kevin Cramer

President  
Commissioner  
Commissioner

IN THE MATTER OF THE PETITION OF  
NORTHERN STATES POWER COMPANY  
D/B/A XCEL ENERGY FOR FUEL  
CLAUSE ADJUSTMENT RECOVERY OF  
MISO DAY 2 NET COSTS AND  
REVENUES

CASE NO. PU-400-05-\_\_\_\_\_

**PETITION**

**OVERVIEW**

As the North Dakota Public Service Commission (“NDPSC” or “the Commission”) is aware, the Midwest Independent Transmission System Operator, Inc. (“MISO” or “Midwest ISO”) is preparing for the transition to the “Day 2 Market,” under the direction of the Federal Energy Regulatory Commission (“FERC”) and pursuant to the Midwest ISO’s Transmission and Energy Markets Tariff (“TEMT”). Implementation of the Day 2 Market will change the manner in which MISO utilities procure energy and how they are charged for resources needed to serve their customers.

With this Petition, Northern States Power Company d/b/a Xcel Energy (“Xcel Energy” or “the Company”) seeks Commission affirmation that certain charges under the TEMT reflect the costs for *fuel and purchased energy* that Xcel Energy will incur to provide electric service to retail customers. As such, they are eligible for recovery pursuant to the Commission’s Fuel Clause Adjustment (“FCA”) rules (North Dakota Administrative Code 69-09-02-39) and the Company's FCA tariffs. Consistent with this affirmation, we also seek approval of a revised FCA tariff rider to specify these terms in our North Dakota Electric Rate Book. Finally, our proposed FCA rider changes would allow certain revenues associated with Day 2 transactions to flow to customers, similar to the approach used with financial instruments purchased to limit electric supply cost volatility (Case No. PU-400-00-46, order dated

June 20, 2000). We respectfully ask Commission affirmation and approval of our proposed changes to the Fuel Clause Rider.

To facilitate implementation of these changes, the Company respectfully requests the necessary variances to permit such cost recovery and certain revenue pass through. The MISO TEMT is presently scheduled to go into effect April 1, 2005. The Company thus respectfully requests the Commission allow this revised tariff to be placed into effect April 1, 2005, on less than 30 days notice (and without suspension), or by the effective date of the MISO Day 2 Market if later than April 1, 2005.

## **II. General Filing Information**

Xcel Energy provides the following information.

### Name, Address, and Telephone Number of Utility

Northern States Power Company d/b/a Xcel Energy  
2302 Great Northern Drive  
PO Box 2747  
Fargo, North Dakota 55401  
(701) 241-8632

### Name, Address, and Telephone Number of Utility Attorney

James P. Johnson  
Assistant General Counsel  
Xcel Energy Services Inc.  
800 Nicollet Mall, Suite 2900  
Minneapolis, Minnesota 55402  
(612) 215-4592

Xcel Energy is submitting this filing on March 4, 2005. We respectfully request Commission approval effective as of April 1, 2005 or by the effective date of the MISO Day 2 Market, if later; and Commission approval to implement the proposed FCA tariff coincident with the implementation of the Day 2 Market. Pursuant to North Dakota Century Code 49-05-05, the Company respectfully requests that the Commission allow the revised FCA

order to be placed into effect on less than 30 days notice for good cause shown, as discussed herein.

E. Utility Employee Responsible for Filing

David H. Sederquist  
Sr. Regulatory Consultant  
Xcel Energy  
2302 Great Northern Drive  
Fargo, ND 58102  
(701) 241-8632

The Company requests that Mr. Sederquist and Mr. Johnson be placed on the Commission's official service list for this proceeding.

## THE PROPOSED CHANGES SERVE THE PUBLIC INTEREST

### A. Background

In Case No. PU-400-00-91, Xcel Energy requested that the Commission approve the transfer of functional control of its transmission system (100kV and above) to the MISO regional transmission organization ("RTO"). By order dated January 31, 2002, the Commission approved the transfer of functional control subject to certain conditions. MISO began "Day 1" RTO operations on February 1, 2002, and MISO has been responsible for, *inter alia*, transmission services and certain regional reliability functions since that time.

On August 6, 2004, FERC conditionally accepted for filing MISO's TEMT.<sup>1</sup> On November 8, 2004, FERC denied all requests for rehearing of the August 6 Order.<sup>2</sup> The Organization of MISO States ("OMS"), to which the Commission is a member, actively participated in many aspects of the TEMT proceedings at FERC.

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 wholesale market 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 our retail native load customers in North Dakota. All Company generation and load will participate in the Day Ahead and Real Time Markets, and generation will be

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<sup>1</sup> Midwest Independent Transmission System Operator, Inc, 108 FERC ¶101,163 (2004) ("August 6 Order")

<sup>2</sup> Midwest Independent Transmission System Operator, Inc, 109 FERC ¶61,157 (2004) ("November 8 Order") Several parties have filed appeals of the FERC orders, which are pending before the D C Circuit Court of Appeals. However, the appeals are not expected to affect Day 2 Market implementation

subject to economic dispatch by MISO. As a result, MISO member utilities must submit load bids into the market, and these purchases of energy from the Midwest ISO and made by Xcel Energy will be an additional cost associated with delivery of generation. However, to the extent that the Company's generation is offered into the market and clears the market, it will be dispatched by MISO. For "self scheduled" or "must run" transactions (as well as bilateral transactions), a Transmission Usage Charge consisting of congestion costs and marginal losses is applied to the delivery. MISO will pay generators at market-clearing prices, and the Company proposes to treat these revenues as a credit to our purchased energy expense. The MISO pricing formula is such that the load purchases and generator credits are offsetting except for congestion and marginal losses

Presently, Xcel Energy and other North Dakota electric utilities (Otter Tail Power and Montana-Dakota Utilities) recover the cost of purchased energy, fuel, delivered losses, and congestion (in the form of redispatched generating units under the NERC Transmission Loading Relief or "TLR" process) through the FCA. When MISO implements the Day 2 Market, the Company will continue to incur these costs, but the name, form and means of calculating costs and revenue will change. As explained below, these new charges and credits will still reflect the fuel and purchased energy cost of serving our retail electric customers. As such, the cost recovery should continue in a manner similar to recovery under the Day 1 market.

We believe that under our proposal, the overall cost for energy included in electric rates will be more comparable to the costs contemplated to be recovered by the FCA statute and rules. Our approach is not an expansion of the scope of the FCA. Rather, the proposal attempts to reflect all of the different costs and credits to expense that will compose the cost of energy delivered to our customers under the TEMT. In implementing this approach, the Company will continue to use the same principles for allocating native and intersystem wholesale costs, assuring that native load has first call on least cost generation resources. As such, we believe that the Commission can and should make the affirmative findings requested by this Petition and approve the proposed FCA Rider tariff changes effective on the implementation date of the Day 2 Market.

## **B. Summary of Relief Requested**

The Company respectfully requests that the Commission affirm that the Company's FCA Rider (as revised) and North Dakota administrative rules allow for FCA recovery of the costs of providing energy delivered to North

Dakota retail customers and thus accommodate recovery and pass through of various Day 2 costs and revenues. Specifically, the Commission should:

- Affirm that existing North Dakota rules allow for FCA recovery of the costs of providing energy to North Dakota retail electric customers and thus accommodate recovery and pass through of various Day 2 costs and revenues billed or paid by MISO.
- Grant any needed rule waivers to effectuate this affirmation, primarily by allowing the pass through of certain revenues received from MISO and allowing for accounting of Financial Transmission Rights and load bid costs and generator credits to be netted in Account 555.
- Approve our proposed revised Fuel Clause Rider tariff that reflects the anticipated MISO charges and credits and their treatment in the FCA effective April 1, 2005.

## **C. Detailed Description of Relief Requested**

### *1. Overview and Benefits of the Day 2 Market Design*

The Day 2 Market is the result of a tariff filing made by the Midwest ISO pursuant to a FERC Order pursuant to Order No. 2000. As a member of the Midwest ISO RTO, Xcel Energy will be subject to the TEMT as a tariff on file with FERC and will be required to participate in the Day 2 Market. Xcel Energy will offer generation into a Day Ahead and Real Time Market. We will bid our load into the Day Ahead Market. Prices for energy will be based upon the market-clearing price for energy plus the cost of congestion and marginal losses. The Company will be allocated Financial Transmission Rights ("FTRs") to hedge its exposure to congestion costs. In addition, in its Order approving the TEMT, the FERC required the Midwest ISO to reimburse load-serving entities for the difference between marginal and average losses. Entities will be allowed to self-schedule both owned and contracted generation so as to avoid exposure to daily market prices. With the appropriate accounting treatment and variances, these transactions can be effectively netted, preserving low cost resources for native load.

The purpose of the Day 2 Market is to produce greater short-term energy supply efficiencies through the region-wide economic dispatch of generation and greater long-term efficiencies by sending price signals as to the most cost-

effective locations for adding generation or transmission to the grid. The Midwest ISO has conducted analyses submitted to the FERC showing that there are benefits to the region from an LMP market design.

The larger dispatch footprint offered by MISO compared to our current generation and purchases offers the potential for energy savings. These savings will occur whenever MISO can dispatch generation units within its footprint at a lower cost than would otherwise have been incurred by individual member market participants (and thus their ratepayers). While it is difficult to predict the magnitude or timing of any potential savings, it is worthwhile to point to specific instances where the Company can expect benefits to accrue to ratepayers. While it is difficult to quantify the benefits of a new market design (since the Company has not operated under it) or the timing of when those benefits will accrue, there are several ways that we anticipate potential savings may occur.

First, while bilateral energy exchanges in today's wholesale environment have enabled the Company to reduce costs for ratepayers, the centrally dispatched market offered by MISO expands the potential for beneficial exchanges. A centralized market should offer greater liquidity and transparency that should provide for more efficient pricing than a bilateral market. As a significant purchaser of energy, Xcel Energy views this as a positive development for its ratepayers. We currently look to reduce fuel costs by making purchases at a price below our incremental cost of production. To the extent MISO's expanded footprint and increased liquidity provide additional opportunities to buy down our costs of generation, savings will accrue to our ratepayers.

Second, the Company currently is forced to operate generation units or make purchases out of economic merit order to maintain reliability for the entire region. In these circumstances, our ratepayers pay higher rates by virtue of the increased fuel costs associated with operating facilities out of merit order. To the extent MISO can redispatch the region to reduce the magnitude of out of merit order generation, savings will accrue to the Company's ratepayers.

Third, the congestion management system being implemented by MISO in Day 2 will promote more efficient use of our 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) procedures. The TLR procedure is a form of rationing that is based on non-economic criteria: all transmission

service schedules affecting the constrained transmission element are curtailed, and often dozens (or hundreds) of transactions may be affected to effectuate a small reduction in physical flow on the constrained facility. Like all physical rationing mechanisms, this system creates inefficiencies compared to a market-based congestion management system provided in MISO Day 2, which will allow MISO to target specific transactions that can most effectively reduce the constraint, allowing the remaining transactions to continue. Specifically, the inherently imprecise TLR procedures result in underutilization of transmission capacity, thus limiting additional economic exchanges between participants. The Day 2 market will replace the "shotgun" approach of TLR with the "rifle shot" approach to congestion management.

There are also long-term benefits associated with locational price signals. Load-serving entities like Xcel Energy will be able to determine with greater precision where generation and/or transmission addition can provide the greatest benefit to ratepayers. That is, where locational prices are consistently high, additions of generation or transmission will provide the greatest likelihood of lowering costs for all ratepayers. While transmission studies can be performed currently that help to inform such decisions, they cannot provide the market-based information that is so critical to a cost/benefit analysis of large resource additions.

Finally, there are reliability benefits associated with Day 2. MISO's improved ability to redispatch generation over a larger footprint will lessen the potential impacts that transmission outages will have on the grid 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 Day 2 will improve reliability for all market participants.

There are also costs associated with implementation of the Day 2 Market and risks associated with the movement to an LMP market design. It is difficult to predict the extent of any costs related to energy or congestion until we begin to experience congestion charges to determine the adequacy of the FTR allocation process. We also do not know the extent of certain market "uplift" costs under the TEMT (e.g., costs allocated by MISO to all users under the TEMT). Finally, while we can reasonably predict the normalized value of costs associated with operations of an energy market, these costs will be incurred primarily on a MWH basis and thus will vary every month based on actual customer energy demand

We expect that over time, the benefits of the new market structure will outweigh these costs. However, this may not occur upon implementation, as a market designed to garner efficiencies from optimized use of the grid will take time for participants in the market to adjust to in making decisions regarding generation offers that will enhance efficiency. Further, savings from more efficient generation and transmission locational decisions may take years to fully realize.

Our petition seeks to address the changes occurring under the new MISO market structure by linking Day 2 costs and revenues/credits through the FCA such that ratepayers pay the net cost of energy delivered under this new market structure.

## 2. *Affirmation regarding FCA Rules*

North Dakota Rules govern the FCA. Administrative Rule 69-09-02-39 states:

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.

The FCA rules then set forth more detailed definitions of "Energy Costs". Rule 69-09-02-39(4)(c) states that "Energy costs" include "The net energy cost of energy purchases, exclusive of capacity or demand charges, *irrespective of the designation assigned to such transaction.*" [Emphasis added.] In addition, section (4)(d) of the automatic adjustment rules requires a credit to Energy Costs for "other energy sold on an economic dispatch basis."

We respectfully request that the Commission affirm that these rules allow for recovery and pass through of TEMT costs and credits from MISO to reflect the actual costs of providing fuel and purchased energy on behalf of retail customers. Without such affirmation – and associated accounting and any needed rule waivers – the Company will not be treated in a manner consistent with current policy in the Day 1 Market. Because the various components of the Day 2 Market are in aggregate comparable to many of our current Day 1 activities and costs incurred that are recoverable under the Company's FCA

tariff and Commission rules, the Commission should affirm the appropriateness of their recovery.<sup>3</sup>

The Company's North Dakota utility operation is not alone in needing to address the impact of a Day 2 Market design. Otter Tail Power Company and Montana-Dakota Utilities have filed similar adjustment clause tariff requests with the Commission. Xcel Energy has filed an application with the Minnesota PUC ("MPUC") that seeks MPUC acknowledgement and FCA tariff changes. A similar request to vary the Energy Adjustment Clause for Iowa electric utilities to facilitate recovery of Day 2 net cost has been granted by the Iowa Utilities Board (IUC). See Order dated May 13, 2004, Docket No. WRU-04-150.

### 3. *Description of Day 2 Costs and Revenues Subject to FCA*

We illustrate the comparability of anticipated Day 2 Market costs and revenues to components of today's environment below. The Company also provides several examples of how costs and revenues under specific transactions would be reflected in the FCA in Attachment A to this petition.

- *Day-Ahead Market.* The Day-Ahead Market, which provides a means for parties to lock in prices for energy in advance of real-time, is an augmentation of economic dispatch currently conducted by individual utilities. It will not differ markedly from how we currently dispatch our system in terms of function. Xcel Energy will perform the same functions we do now in dispatching generating plants, except that dispatch will be under MISO's centralized security constrained dispatch market regime and units will be dispatched based on prices offered to the market (unless the unit is self-scheduled and/or designated as a "must-run" resource).

The generation resources of utilities will be offered into the Day Ahead Market and if accepted, will receive LMP prices at the location of the resource and load will make purchases from this market based on Day Ahead LMP prices at various load locations (referred to as "nodes"). The LMP prices include the market-clearing cost of energy and the cost of congestion and marginal losses at various nodes. This structure

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<sup>3</sup> As discussed in more detail below, Rule 69-09-02-39, Section 10, provides that "If a particular circumstance prevents the use of a standard or its use would result in undue burden, the Commission may for good cause shown, permit deviation from a standard." If necessary, the Company requests that the Commission find there is good cause to permit a "deviation" from the existing FCA Rider and FCA rules to allow FCA treatment of the Day 2 TEMT costs and revenues

tends to separate generation from retail load. However the MISO has mechanisms that assure that the Company will retain control over our generation through self-scheduling and/or must run designations and Xcel Energy's generating resources will remain available to serve native load through the combination of appropriate ratemaking and resource scheduling strategies.

- *Preserving Native Transactions.* There are several approaches we expect to use to ensure that our native load continues to have first call on our low-cost resources. For transactions in the Day 2 Market with MISO, the most common means of achieving this result is to designate a unit as must run or to self-schedule units, assuring that the electric output is taken by the market. Our generation fleet will be making sales to the MISO at the same time our load is purchasing from the MISO. By flowing the cost of fuel through Account 501 and netting what is referred to as the generation market sale and load purchase along with revenues or expenses from FTRs and Marginal Loss Compensation revenues (discussed below) through the FCA, native load customer in North Dakota will pay a cost that is comparable to the cost of producing the electricity from rate based generation, as is the case today, with the new feature of optimized congestion management. Under our proposal certain revenue streams related to generator payments and FTR revenues will be credited to expense in Account 555 thereby netting the costs of congestion and load purchases made on behalf of retail load.
- *Bilateral Agreements.* The Company has many longstanding bilateral wholesale power contracts, where the Company can purchase from or sell to another market participant (e.g., OTP or Manitoba Hydro) when economically advantageous to do so. Bilateral contracts scheduled in the Day-Ahead Market will be treated as if the resource is an owned generation resource of the Company, with Day 2 a Transmission Usage charge is applied to the transactions based on LMP prices at the point of injection and the point of delivery.
- *Real-Time Market.* MISO's Real-Time Market will coordinate energy flows throughout the operating day. The Real-Time Market provides a mechanism for market participants to cover imbalances and deviations from their Day-Ahead schedules, similar to what the Company currently does on an hourly basis. Unlike the Day Ahead Market,

congestion in the MISO Real Time Market is not capable of being hedged through the use of FTRs.

- *MISO Operations and uplift costs.* The Company will be charged for MISO market operations and for certain energy market costs that will be allocated to all load. These charges are incurred as part of the wholesale tariff that establishes the LMP market and billed primarily on a MWH basis and are an extension of the variable costs of procuring energy. (These costs are described in more detail below).
- *Financial Transmission Rights.* MISO will administer a system of financial transmission rights (“FTRs”) to allow parties a hedge against price risk from the congestion component of Day Ahead LMP prices. The primary objective of FTRs is to keep current transmission customers whole with respect to congestion costs to the extent possible. An FTR is a financial instrument, not a physical right to transmission capacity.<sup>4</sup> Xcel Energy will be allocated FTRs based on preexisting physical transmission rights to deliver energy to hedge against the congestion charge components of an LMP energy price. In addition, we may participate in future FTR auctions for such rights to hedge ongoing incremental transmission use.

The Company plans to account for FTR revenues/credits to expense and expenses on a unit specific, transaction basis (retail vs. wholesale) as the allocated FTRs will be associated with paths for a generation unit or a bilateral transaction. To the extent that we are assigned either positive (revenues/credits to expense) or negative (expenses) FTRs for resources not taken by the Day Ahead Market, we will allocate these revenues and expenses to native load. Additionally, we will buy and sell FTRs to optimize our position in a secondary FTR market, when this market is developed.

- *Marginal Losses Compensation.* In its Order approving the TEMT, FERC required MISO to return to transmission customers the difference between marginal losses and average or historical losses for a five-year transition period. The net effect is that there should be little impact on

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<sup>4</sup> The primary advantage of organizing dispatch around financial -- as compared to physical -- rights to the grid is that FTRs do not restrict economic dispatch. In strict, physical-rights systems (i.e., the historic MAPP trading practices or MISO Day 1), the physical transmission rights must match the supply transaction to guarantee physical access, and the value of any rights not “used” is lost.

FCA costs from including both LMP costs and this revenue stream. Today, the Company recovers the cost of system average delivered losses in the FCA. The Company proposes to flow the marginal loss revenues to retail customers through the FCA and to the extent possible will allocate these revenues on a transactional basis.

- *Schedules 16 and 17*

Schedules 16 and 17 to the MISO TEMT contain charges associated with MISO's administration of the FTR and Energy Market functions. Schedule 16 provides for the recovery of all costs incurred by MISO in providing FTR services and includes costs associated with: 1) coordination of FTR bilateral trading; 2) administration of FTRs allocation, assignment, or auction and 3) simultaneous feasibility analyses to determine the total combination of FTRs that can be outstanding and accommodated by the Midwest ISO at a given point in time. Schedule 17 provides for the recovery of all costs incurred by the Midwest ISO in providing: 1) market modeling and scheduling functions; 2) market bidding and LMP support, 3) enabling least-cost Security Constrained Economic Dispatch; and 4) market monitoring functions. The Company will be billed Schedule 16 and 17 fees and will be obligated to pay them to MISO as filed rates.

- *Uplift Charges*

FERC has approved four "uplift" charges to be assessed to all Day 2 market participants, including Xcel Energy. These uplift charges will also be billed to the Company and payment will be required under the TEMT as a filed rate.

The first is an Offer Revenue Sufficiency Guarantee Charge. The TEMT guarantees recovery of a market participant's generation offer for resources committed by MISO and scheduled in the MISO market operations. By guaranteeing that costs will be met, MISO is able to select and commit resources at minimum cost while preserving reliability. Without such resources committed in the forward market, MISO would have to commit units with higher production costs. Hence, in the event that there is a shortfall experienced by a generator (when comparing its offer to the market-clearing price), this deficiency will be borne by MISO and "uplifted" by recovering the cost from all market participants based on the energy delivered to their load.

The second uplift charge -- termed Option B uplift -- compensates market participants in highly congested areas who may incur significant congestion costs compared to other market participants. FERC required MISO to establish an optional, voluntary FTR protocol for transmission customers in these highly congested areas. In exchange for forgoing certain rights and abiding by certain rules, these customers will be assured that -- to the extent their FTRs are insufficient to cover congestion charges -- the difference will be made up by other MISO customers through this uplift charge. These costs would be borne by all other market participants, including Xcel Energy's native load.

The third uplift charge is for Uncollectible Default Accounts. This charge recovers MISO's costs associated with the default of market participants regarding their obligations in MISO's market. FERC has found it reasonable for this cost to be borne by all participants in all regional transmission organization.

The last uplift is the "revenue neutrality uplift" which assures that any excess costs or excess revenues be assessed or returned to load serving market participants.

Because these are FERC-approved filed rates required in the procurement of energy services for our customers, we believe they are appropriate for recovery as a cost of energy delivered. The majority of these costs will be assessed on a MWH basis and thus charged very much like an energy purchase.

As noted above, we anticipate that there is the potential for both short term and long run benefits in the form of lower energy costs and optimized investments in generation and transmission that will accrue to customers. Thus, a continuation of the current mechanism for recovery of all variable fuel and energy related net costs through the Company's FCA is appropriate

While our proposal attempts to ensure that customers retain the same value that they have today, taking into consideration new market conditions, we recognize that there is uncertainty involved with implementation of major market changes as provided by the TEMT. For example:

- There is the potential that the allocation of FTRs could be limited if insufficient rights are available and that we are allocated negative FTRs.

- There is the potential that Xcel Energy could be allocated “counterflow” FTRs to allow FTRs to be allocated to other MISO participants, and such counterflow FTRs could produce negative values (e.g., expenses to be recovered)
- On days of higher load than was settled in the Day Ahead market, real time purchases will be subject to congestion charges based on market conditions.

Given these factors and other uncertainties, no one can guarantee the ultimate impact on customers, although it is our expectation that over time benefits will accrue to customers from a market that optimizes the use of the transmission grid and provides access to a broader set of resources in a more efficient manner than exists today. With this filing and our participation in the development of the Day 2 Market, we are working to ensure customers obtain the value of the new market while retaining the benefit of the existing framework to the extent possible.

Attachment A provides examples of how we expect to apply these new market features to specific transactions and the resulting outcome under today’s environment, our proposal and the TEMT with no modification to the FCA.

#### 4. *FCA Treatment of Both Costs and Revenues is Appropriate*

The costs Xcel Energy will incur under Module C of MISO’s TEMT are clearly linked to the purchase of least-cost energy for our native load customers. Participation in this Market is required by FERC for participants in MISO, and it represents how we will procure most of our energy for our customers going forward.<sup>5</sup> By proposing to flow through the FCA both the costs credits and revenues associated with the Day 2 Market, we believe that – even though the approach is new -- the FCA will reflect the same policy in place today: that the FCA mechanism, rather than a base rate approach, be used to capture the cost of energy delivered to retail customers. The net costs under the proposal are incurred for energy under a Day 2 regime As

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<sup>5</sup> The transition to MISO Day 2 is analogous to the transition in the wholesale natural gas market in the late 1980s. At that time, FERC prohibited the interstate gas pipelines from making bundled wholesale natural gas sales, and required structural separation of the transmission function from the wholesale gas sales and storage functions. FERC ordered pipelines to modify their FERC tariffs accordingly. The Company’s wholesale natural gas procurement function had no option but to implement these federal mandates: the Company was required to begin direct procurement of natural gas supplies, storage services, etc., and reflected those costs in its Purchased Gas Adjustment (now Cost of Gas) tariffs. The resulting wholesale gas market proved to be significantly more efficient than the prior structure.

such, we believe the Commission can find that its purpose in establishing the FCA, to reflect changes in these costs outside of rate cases, is satisfied by granting this Petition.

With respect to other key components of the Day 2 Market, we note that FTRs are financial instruments, not direct costs of purchased energy, making them similar to the financial instruments previously approved for recovery through the FCA (see Case No. PU-400-00-46, order dated June 20, 2000). Because FTRs hedge congestion costs and are an integral part of the new market design, including the applicable portion of FTR revenues/credits or costs is likewise appropriate and consistent with previous Commission precedent.

Since the purpose and application of the FCA Rules is to provide for recovery of the cost of energy delivered to customers, the Commission should affirm that recovery of Day 2 Market costs through the modified FCA tariff rider is appropriate.

#### *5. Proposed FCA Tariff Rider And Implementation*

##### *a. The Proposed FCA Tariff Rider Revisions*

Attachment B contains our proposed FCA Rider to implement the Day 2 Market changes and reflect TEMT costs. As discussed previously, the Company respectfully requests approval of this tariff to be effective April 1 with the implementation of MISO's TEMT, without suspension and with less than 30 days notice.

The tariff rider provides for inclusion in the FCA, costs and revenues resulting from generation resources (including bilateral agreements) offers to the market and load purchases from the market as linked to the underlying fuel or purchased energy costs. In addition, FTR revenues and expenses, operational costs of an RTO (e.g., Schedule 16, 17 and uplift costs) and Marginal Loss Compensation revenues associated with underlying native load fuel or purchased energy costs are also considered linked to the cost of energy and included in the FCA. Because all components of the new energy market and their names may evolve, the language focuses on costs and revenues associated with FERC approved RTO markets, excluding those costs and revenues associated with intersystem sales. The revised proposed tariff rider, Attachment B, adds a new Paragraph 3 to reflect the treatment of these various new RTO costs and credits to expense as well as the Marginal Loss compensation revenues.

*b. Accounting and Settlements*

We seek Commission approval to book payments from generation offers and FTR payments to the market made on behalf of retail load to Account 555 and Marginal Loss Compensation revenues in Account 456. Load purchases (which include the costs of congestion and marginal losses) and native load FTR expenses would be booked to Account 555. We anticipate establishing sub-accounts or business unit codes for capturing native transactions to more easily identify linked costs and revenues. We have pursued net accounting where payments are treated as a credit to expense to avoid jurisdictional concerns raised if native generation is treated as a wholesale sale. As such, we seek approval of this accounting treatment.<sup>6</sup>

The settlements process involved with the Day 2 Market will add a significant layer of complexity to our billing and accounting processes. The Midwest ISO will bill the Company weekly. The bill will be settled for Day Ahead, Real Time and settle LMPs and FTRs. Each bill will be supported with individual settlement statements and a summary settlement statement for each operating days over multiple periods including a 7 day (“S7”), 14 day (“S14”), a 55 day (“S55”) and 105 day settlement period as well as a dispute process following settlement. Xcel Energy has been actively preparing for implementing the "back office" support for Day 2 and we are willing to provide additional information to the Commission and/or staff of how we intend to manage this process, pursuant to Rule 69-09-02-39, Part 11.

*6. Alternative Request for Relief Under Rule 69-09-02-39, Part 10*

While the Company believes its proposal for treating Day 2 Market costs is consistent with the purpose of the FCA and our FCA Rider (as amended) and should be affirmed, we recognize that the calculations performed in accordance with the Rules did not anticipate all of the charges provided by the TEMT or specifically provide for the pass-through of associated credits/revenue. Consequently, to approve the proposed tariff, certain rule variances may be needed. We respectfully request any variances that are deemed required to implement the proposed tariff.

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<sup>6</sup> We note that the FERC is seeking comment on the need for a rulemaking regarding RTO accounting. See Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators, Notice of Inquiry, 108 FERC ¶ 61,237, Docket No. RM04-12-000 (September 2004). Thus, these designations are likely to evolve.

N. D. Administrative. Rule 69-09-02-39, Section 10, allows the Commission to vary its Rules to accommodate situations such as this:

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.

Here, the FERC has mandated a fundamental modification of the wholesale electric marketplace for the Midwest. The Commission's FCA rules have not been updated to reflect this change. Section 10 provides the flexibility to respond to market changes. This petition demonstrates there is good cause to do so at this time. As the MISO Day 2 Market is implemented, the Commission can determine if or how the FCA rules may need to change to reflect this evolution in the broader wholesale market as mandated by FERC.

#### *7. Additional FCA Reporting*

We recognize that the transition to the Day 2 Market is of significant interest to the Commission. Rule 69-09-02-29, Section 11, allows the Commission to "require any filings and reports that may be necessary to carry out [its] review." To ensure on-going information exchange regarding the transition, we propose to provide in our monthly FCA filings a breakdown of the various components of TEMT charges charged to retail customers 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.

We propose to begin this additional reporting in the second month after MISO Day 2 Market operations begin. This type of reporting should permit the Commission to monitor the impact of Day 2 on our costs to customers.

#### CONCLUSION

The MISO Day 2 Market poses a significant change for utilities and regulators. We believe that our proposal for treatment of the various charges associated with Day 2 will most appropriately retain the current "Day 1" balance between customers and the Company offered by the FCA. For that reason, we respectfully request that the Commission:

- Affirm the appropriateness of recovery through the Company's FCA Rider and the Commission's FCA rules. If necessary, allow for FCA treatment pursuant to Rule 69-09-02-39, Section 10.
- Approve the net accounting treatment so that payments by MISO to generators and payments associated with FTRs are credited to expense in the FCA.
- Approve our proposed FCA tariff Rider that implements these changes effective April 1, 2005, without suspension and with less than 30 days notice, for good cause shown.

We believe these proposals are reasonable and appropriate, providing a path toward the new energy marketplace. We are willing to provide any additional information the Commission may require when considering this proposal.

Respectfully submitted,



David H. Sederquist  
Sr. Consultant, Regulation/Finance  
Northern States Power Co. d/b/a/ Xcel Energy

**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 the costs currently included in the FCA and the new wholesale purchase cost.

**Scenario 1**  
**Self-Scheduling And No Congestion**

Xcel Energy self schedules 500 MW of generation to load from Sherco 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). 500 MW of Xcel Energy load 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 Sherco 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:

- Xcel Energy pays \$21.50/MWH (for 500MW\*24 hours) to the Midwest ISO.
- The Company incurs costs of \$10/ MWH for fuel.
- Xcel Energy receives a payment of \$21.00/MWH (for 500 MW\*24 hours) from the Midwest ISO for its generation.

Alternative FCA Outcomes for Customers:

- Today: Customers are charged \$10 for cost of fuel.
- 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).<sup>7</sup>

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<sup>7</sup> Although not shown, Xcel Energy will be compensated for the difference between marginal and average losses by the Midwest ISO and we propose to return these amounts associated with native load through the FCA. The mechanism for the return of this revenue is not known at this time. Also, we do not attempt to reflect MISO operational costs in this or any of the other examples

## Scenario 2 Self-Scheduling With Congestion

Xcel Energy self schedules 500 MW of generation to load from Sherco 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). 500 MW of Xcel Energy load 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 Sherco for this period is \$10/MWH. This example assumes that the Company attained FTRs for the Sherco path for the entire 500 MW and the entire 24 hours.

### Resulting Charges:

- Xcel Energy pays \$51.50/MWH (for 500MW\*24 hours) to the Midwest ISO.
- The Company incurs costs of \$10/ MWH for fuel.
- Xcel Energy receives a payment of \$21.00/MWH (for 500 MW\*24 hours) from the Midwest ISO for its generation.
- Xcel Energy receives FTR payments of \$30/MWH (for 500 MW\*24 hours) from the Midwest ISO.

### Alternative FCA Outcomes for Customers:

- Today: Customers are charged \$10 for cost of fuel.
- Company's Day 2 Proposal: Customers are charged the net of all costs and payments 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)<sup>8</sup>

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<sup>8</sup> As noted above, Xcel Energy will be compensated for the difference between marginal and average losses by the Midwest ISO and will flow the retail amounts through the FCA

### Scenario 3<sup>9</sup> Negative FTRs In Day Ahead Market.

In this example, we bid our load in the day-ahead market and determine that we need to take 500 MW from Sherco for 24 hours in the Day Ahead market. Load is picked up by at a price of \$25/MWH (consisting of energy at \$25/MWH and no congestion). We self-schedule the Sherco plant into the market and it was purchased by MISO at a price of \$40/MWH (\$25/MWH for energy and \$15/MWH for congestion). The fuel cost for Sherco generation is \$10/MWH. The Company holds FTRs for all 500 MW from Sherco for this day.

#### Resulting Charges:

- Xcel Energy pays \$25/MWH (for 500MW\*24) to the Midwest ISO.
- The Company incurs costs of \$10/ MWH for fuel.
- Xcel Energy receives a payment of \$40 /MWH (for 500 MW\*24) from the Midwest ISO for its generation.
- Xcel Energy makes an FTR payment of \$15/MWH (for 500 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.
- Company's Day 2 Proposal: Customers are charged the net of all costs and payments associated with serving native load or \$10/MWH (reflecting the that the FTRs were negative)

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<sup>9</sup> This example and the remaining ones do not address the costs associated with marginal losses or Marginal Loss Compensation revenues in order to simplify the transactions

## **Scenario 4 Bilateral Purchase**

This example involves a long-term bilateral purchase of 500 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 \$25/MWh and \$0/MWh for congestion). Also, assume that the Day Ahead market for load clears at \$65/MWh (consisting of energy at \$25/MWh and congestion of \$40/MWh). Xcel Energy holds 500 MW FTRs for all 16 hours on this long-term purchase.

### **Resulting Charges:**

- Xcel pays the holder of the bilateral agreement \$35/MWh for the energy delivered.
- Xcel Energy pays \$65/MWh (for 500MW\*16 hours) to the Midwest ISO.
- The Company is paid \$25/MWh for the LMP price at the injection point.
- Xcel Energy receives a payment of \$40/MWh (for 500 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
- Company's Day 2 Proposal: Customers are charged the net of all costs and payments revenues (including FTR payments) associated with serving native load or \$35/MWh.

## Scenario 5 Real-Time Purchase With Load Above Forecast

Xcel Energy native load is greater than settled in the Day Ahead Market for 3 hours and we purchase 200 MWHs real time at a price of \$100/MWH (which includes an energy price of \$80/MWH and a congestion price of \$20/MWH). Because Black Dog was not committed day ahead it can inject at our load in real time. An equal amount of generation from Black Dog (200 MWHs) was picked up in real time at a price of \$80/MWH. The cost of fuel for the Black Dog natural gas unit during real time was \$50/MWH).

### Resulting Charges:

- Xcel Energy pays an LMP cost for energy of \$100/MWH (for 200MW\*3 hours) to the Midwest ISO.
- The Company incurs fuel costs of \$50/MWH.
- Xcel Energy 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.
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load or \$70.00/MWH.

NORTHERN STATES POWER COMPANY (MINNESOTA)  
ELECTRIC RATE BOOK  
NORTH DAKOTA

Sheet No: E 76 2  
Revision: 143th

FUEL CLAUSE RIDER NO. 1

There shall be added to or deducted from the net monthly bill \$0 00001 per kilowatt-hour for each \$0 00001 increase above or decrease below \$0 01092 in the fuel cost per kilowatt-hour sales

The fuel cost shall be the sum of the following for the most recent four month period plus unrecovered (or less over-recovered) prior cumulative energy costs

- 1 The cost of fossil, nuclear, and other fuels, including but not limited to biomass, wood, and refuse derived fuel (RDF), consumed in the Company's generating stations as recorded in Accounts 151 and 518
- 2 The net energy cost of energy purchases, including gains, losses, premium payments, and transaction costs related to financial instruments and linked transactions used to mitigate price volatility, as recorded in Account 555 exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased
  - a On an economic dispatch basis, including 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,
  - b. From a renewable energy source, including but not limited to hydropower, wood, windpower, and biomass,
  - c From a qualifying facility as defined in 18 C F R Part 292
- 3 Net Costs or revenues linked to the Company'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
- ~~3-4~~ The actual identifiable fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above
- ~~4-5~~ Less the fuel related costs recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis

The kilowatt-hour sales shall be all kilowatt-hours sold excluding intersystem sales for the most recent four month period

Filing Date: 03-04-05

By: K. T. Larson  
Vice President, Jurisdictional Relations

Effective: 04-01-05

NDPSC Case No: PU-400-05-\_\_\_

Order Date:

**NORTHERN STATES POWER COMPANY (MINNESOTA)  
ELECTRIC RATE BOOK  
NORTH DAKOTA**

**Sheet No: E 76 2  
Revision: 14th**

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- 2 The net energy cost of energy purchases, including gains, losses, premium payments, and transaction costs related to financial instruments and linked transactions used to mitigate price volatility, as recorded in Account 555 exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased
  - a On an economic dispatch basis, including 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,
  - b From a renewable energy source, including but not limited to hydropower, wood, windpower, and biomass,
  - c From a qualifying facility as defined in 18 C F R Part 292
- 3 Net Costs or revenues linked to the Company'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
- 4 The actual identifiable fossil, nuclear, biomass, wood, and refuse-derived fuel (RDF) costs associated with energy purchased for reasons other than identified in (2) above
- 5 Less the fuel related costs recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis

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The kilowatt-hour sales shall be all kilowatt-hours sold excluding intersystem sales for the most recent four month period

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