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Missouri Public Service Commission

EXHIBIT

Exhibit No.:	407
Issue(s):	Fuel Adjustment Clause/ Interruptible Rate
Witness/Type of Exhibit:	Kind/Rebuttal
Sponsoring Party:	Public Counsel
Case No.:	ER-2007-0002

REBUTTAL TESTIMONY

OF

RYAN KIND

Submitted on Behalf of
the Office of the Public Counsel

UNION ELECTRIC COMPANY D/B/A AMERENUE

Case No. ER-2007-0002

February 2, 2007

OPC Exhibit No. 407
Case No(s). ER-2007-0002
Date 3/14/07 Rptr MV

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a	)	
AmerenUE for Authority to File Tariffs Increasing	)	**Case No. ER-2007-0002**
Rates for Electric Service Provided to Customers	)	Tariff No. YE-2007-0007
in the Company's Missouri Service Area.	)	

AFFIDAVIT OF RYAN KIND

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Ryan Kind, of lawful age and being first duly sworn, deposes and states:

1. My name is Ryan Kind. I am a Chief Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached affidavit are true and correct to the best of my knowledge and belief.

Ryan Kind

Ryan Kind

Subscribed and sworn to me this 5th day of February 2007.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

JERENE A. BUCKMAN
My Commission Expires
August 10, 2009
Cole County
Commission #05754036

Jerene A. Buckman

Jerene A. Buckman
Notary Public

My commission expires August 10, 2009.

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REBUTTAL TESTIMONY

OF

RYAN KIND

UNION ELECTRIC COMPANY

CASE NO. ER-2007-0002

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Ryan Kind, Chief Energy Economist, Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102.

Q. ARE YOU THE SAME RYAN KIND THAT SUBMITTED DIRECT AND REBUTTAL TESTIMONY IN THIS CASE REGARDING REVENUE REQUIREMENT ISSUES AND DIRECT TESTIMONY ON DECEMBER 29, 2006 REGARDING FUEL ADJUSTMENT CLAUSE ISSUES?

A. Yes, I am.

I. INTRODUCTION AND RECOMMENDATONS

Q. PLEASE IDENTIFY THE ISSUES THAT YOU WILL BE ADDRESSING IN YOUR REBUTTAL TESTIMONY.

A. The major issues that are addressed in this testimony include:

- How MISO charges should be passed through the Fuel Adjustment Clause (FAC) tariff proposed by Union Electric Company (UE or the Company) in this case.
- UE's Industrial Demand Response pilot.

II. UE's Proposed Fuel Adjustment Clause Tariff And MISO Charges

Q. WHOSE DIRECT TESTIMONY REGARDING UE'S FAC WILL YOU BE ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. I will address the testimonies of UE witness Martin Lyons.

Q. HAS THE OFFICE OF THE PUBLIC COUNSEL (PUBLIC COUNSEL OR OPC) TAKEN A POSITION IN THIS CASE REGARDING WHETHER UE'S FAC PROPOSAL SHOULD BE APPROVED BY THE COMMISSION?

A. Yes, Public Counsel's recommendation that the Commission deny UE's proposal to establish a FAC because the approval of such a clause would not be consistent with the public interest and the basis for that recommendation are set forth in my December 29, 2006 FAC testimony. The testimony that follows should not be interpreted as a change in OPC's position regarding UE's FAC proposal. Instead, the following testimony is intended to give the Commission guidance on how to review the specifics UE's FAC proposal if, despite OPC's recommendation to the contrary, the Commission believes that UE is a suitable candidate for using a FAC.

Q. DID UE WITNESS LYONS EXPLAIN WHICH MISO CHARGES SHOULD FLOW THROUGH THE FAC IN HIS DIRECT TESTIMONY?

A. No. Despite the fact that there are over thirty separate MISO charges that the Company presumably would want to flow through the FAC, Mr. Lyons had no testimony addressing which of these charges should be flowed through and how the various charges and revenue credits should be allocated between sales to native load and other sales. The schedules to Mr. Lyon's testimony only contain very limited references to MISO costs and fails to address the numerous MISO charges in the level of detail that would be necessary for the actual implementation of a FAC.

Q. IS IT NECESSARY TO ADDRESS THE MISO CHARGES THAT WOULD BE ELIGIBLE FOR INCLUSION IN UE'S FAC AT THIS TIME?

A. Yes. If these charges and the manner in which they are accounted for and allocated between sales to native load and other sales is not specified in detail, then there is no way that the Commission can make an informed decision about the reasonableness of UE's proposed FAC because it will lack the competent and substantial evidence necessary to make such a decision. For example, how could the Commission determine that a FAC is reasonable unless it knows whether there will be a reasonable allocation of Financial Transmission Right (FTR) charges between sales to native load and other sales?

4 CSR 240-20.090 requires the Commission to make certain determinations regarding a FAC application and the rate schedules associated with it before deciding whether to approve, modify or reject the FAC application. OPC does not believe that the Commission could make such a decision without reviewing all of the details about which MISO costs and revenues would be eligible for inclusion in the FAC and the specific manner in which these costs would be accounted for and allocated between sales to native load customers and other customers.

Q. ARE YOU FAMILIAR WITH ANY EFFORTS THAT OTHER STATE COMMISSIONS HAVE MADE IN DETERMINING WHICH MISO COSTS AND REVENUES WOULD BE ELIGIBLE FOR INCLUSION IN THE FAC AND THE SPECIFIC MANNER IN WHICH THESE COSTS WOULD BE ACCOUNTED FOR AND ALLOCATED BETWEEN SALES TO NATIVE LOAD CUSTOMERS AND OTHER CUSTOMERS?

A. Yes. On December 20, 2006, the Minnesota Public Utilities Commission (MPUC) issued its "ORDER ESTABLISHIING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS in Docket Nos. E-002/M-04-1970, E-015/M-05-277, E-017/M-05-284, and E-

001/M-05-406. In this order (see Attachment 1) the MPUC addressed in detail which MISO costs and revenues will be eligible for inclusion in the FAC and the specific manner in which these costs will be accounted for and allocated between sales to native load customers and other customers. While OPC may not agree with every determination that is made in this order regarding MISO day 2 costs and FACs, we have directed the Commission's attention to this document because it provides the level of analysis and specificity regarding FAC tariff language that would be necessary for the Commission to make a determination of the reasonableness of UE's proposed FAC and the and the rate schedules associated with it.

III. UE's Proposed Industrial Demand Response Pilot

Q. HAS UE PROPOSED A NEW INDUSTRIAL DEMAND RESPONSE PROGRAM IN THIS CASE?

A. Yes. The Company has proposed a new Industrial Demand Response Pilot (Industrial Pilot). The new proposal is supported in the testimony of UE witness Philip Hanser and discussed in the direct testimony of MEG witness Billie LaConte.

Q. DOES PUBLIC COUNSEL SUPPORT THE PROPOSED INDUSTRIAL PILOT?

A. No. UE is currently engaged in an extensive IRP process that was agreed upon by the parties who actively participated in UE's recent IRP filing case, Case No. EO-2006-0240. A substantial part of the agreed upon process is a comprehensive review of UE's DSM programs (demand response and energy efficiency programs). A consultant has been hired to facilitate this process and perform analysis. A major portion of the consultant's DSM work is to facilitate workshops where all stakeholders (including industrial customers and their representatives) are encouraged to participate. The second stakeholder meeting in this process will be held tomorrow at Ameren's offices in St.

Louis. Public Counsel has asked the Company to encourage its industrial customers to participate in these workshops. OPC believes that these workshops are the place where programs such as the Industrial Pilot should be designed and analyzed because of the technical expertise available in the workshops and the ability to evaluate the cost-effectiveness of programs like this with the integrated and risk analysis modeling tools that are used in the IRP process.

Approving the proposed Industrial Pilot in this case would be based on very limited input and analysis compared to what is available in the IRP process. Public Counsel does not believe we should be offering customers programs at this time that are likely to be replaced or offered in a different manner after the IRP process is completed about one year from now.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Ken Nickolai	Commissioner
Marshall Johnson	Commissioner
Phyllis Reha	Commissioner
Thomas Pugh	Commissioner

In the Matter of Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances	ISSUE DATE: December 20, 2006 DOCKET NO. E-002/M-04-1970
In the Matter of Minnesota Power's Petition for Approval of Revision to Rider for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Day 2	DOCKET NO. E-015/M-05-277
In the Matter of Otter Tail Power Company's Petition for Approval of Revision to Rider for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Day 2	DOCKET NO. E-017/M-05-284
In the Matter of Interstate Power and Light Company's Petition for Approval of Revision to Rider for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Day 2	DOCKET NO. E-001/M-05-406 ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS

PROCEDURAL HISTORY

On June 23, 2006, the Commission received a Joint Report and Recommendation (Joint Report) filed by –

- Interstate Power and Light Company (IPL),
- the Midwest Independent Transmission System Operator, Inc. (MISO),
- the Minnesota Chamber of Commerce,
- the Minnesota Department of Commerce (the Department),
- Minnesota Power,
- Northern States Power Company d/b/a Xcel Energy (Xcel),
- Otter Tail Power (OTP), and
- the Large Power Intervenors (LPI), a coalition of energy-intensive industries.[1]

[1] LPI consists of Blandin Paper Company (UPM_Kymmene); Hibbing Taconite Company; Mittal Steel, USA; Sappi Cloquet, LLC; Stora Enso, United States Steel Corporation and United Taconite, LLC. See January 23, 2006 Comments in Docket No. E-015/M-05-277.

The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) also participated in preparing the report, but declined to support its recommendations. The Joint Report recommended, among other things, that the Commission convene a technical conference for the parties to present their report.

On July 24, 2006, the Department and RUD-OAG filed comments supporting the idea of convening a technical conference, among other things.

On August 7, 2006, the Commission received reply comments from RUD-OAG, and collectively from the utilities.

On October 31, 2006, the Commission convened a technical conference at which the parties provided a summary of the Joint Report.

On November 6, 2006, the utilities filed supplemental comments.

This matter returned to the Commission on November 7, 2006.

FINDINGS AND CONCLUSIONS

I. Background

A. FERC and RTOs

The Federal Energy Regulatory Commission (FERC) has jurisdiction over the transmission of electricity, and the sale of electric energy at wholesale terms, in interstate commerce.[2] To facilitate regulation, FERC directs utilities within its jurisdiction to maintain records according to its Uniform System of Accounts.[3]

FERC encourages public utilities that own, operate or control interstate transmission facilities to join regional transmission organizations (RTOs).[4] An RTO is a voluntary association of transmission facility owners organized "for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services."[5]

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[2] 16 U.S.C. § 824.

[3] 18 U.S.C. pts. 1-399.

[4] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285; FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom.* Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[5] 18 C.F.R. § 35.34(a).

The Minnesota Public Utilities Commission authorized IPL, Minnesota Power, OTP and Xcel to transfer operational control of transmission facilities to an RTO called the Midwest Independent Transmission System Operator, Inc. (MISO).[6]

B. MISO and the Day 2 Market

MISO subsequently adopted a new tariff initiating "Day 2" operations.[7] MISO's tariff recharacterizes the way in which utilities provide electricity for the customers they are obligated to serve ("native load customers"[8]), including retail customers. Traditionally the utilities are understood to generate most of the electricity needed to serve their customers, and to buy or sell any surplus or deficit from neighboring utilities. In contrast, MISO's tariff describes virtually all electric generation as a sale of electricity into a wholesale market, and describes the provision of electric service to entail a purchase of power back from the market.

According to the tariff, the Day 2 Market encompasses both the "Day Ahead Market" and the "Real Time Market." To participate in the Day Ahead Market, utilities forecast where customers will be demanding electricity the next day, and the magnitude of the demand. Petitioners also designate the generators ("network resources")[9] they will make available to meet the total system's needs, and the terms under which each generator would provide electricity to the market if selected ("dispatched"). MISO then creates a plan to match supply with demand, consistent with the constraints of the generators and the transmission grid. The following day – the Real Time Market – MISO implements its plans, adjusted to accommodate changes arising from, for example, unanticipated hot weather or a mechanical failures at a power plant.

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

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[6] *In the Matter of the Petition for Approval to Transfer Functional Control of Certain Transmission Facilities* [of Xcel] *to the Midwest Independent System Operator*, Docket No. E-002/M-00-257 ORDER AUTHORIZING TRANSFER WITH CONDITIONS; *In the Matter of Minnesota Power's Petition for Approval of Transfer of Operational Control of Transmission Facilities*, Docket No. E-015/PA-01-539 ORDER AUTHORIZING TRANSFER WITH CONDITIONS; *In the Matter of Otter Tail Power Company's Petition for Approval of Transfer of Operational Control of Transmission Facilities to the Midwest Independent System Operator*, Docket No. E-017/PA-01-1391 ORDER AUTHORIZING TRANSFER WITH CONDITIONS; *In the Matter of Interstate Power Company's Petition for Approval of Transfer of Operational Control of Transmission Facilities to the Midwest Independent System Operator*, Docket No. E-001/PA-01-1505 ORDER AUTHORIZING TRANSFER WITH CONDITIONS (May 9, 2002).

[7] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).

[8] TEMT § 1.208 (issued May 27, 2005).

[9] TEMT §§ 30, 69 (issued May 27, 2005).

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

Given transmission constraints, parties contracting to buy or sell electricity to each other bear the risk that the low-cost source of electricity may not be allowed to run, and that a higher-cost generator will be substituted. MISO's tariff provides for parties to mitigate this risk by acquiring financial transmission rights (FTRs). FTRs do not ensure that any specific generator will be dispatched; they merely help a party hedge the financial risk that a low-cost generator will not be permitted to operate, and that a costlier generator will be substituted. MISO allocates many FTRs to the petitioners.

Since April 2005, MISO has been billing its members, including IPL, Minnesota Power, OTP and Xcel, for the cost of its Day 2 operations. MISO divided these costs into the thirty-two "charge types" listed in the attachments to this Order.[10]

C. Base Rate and the Fuel Clause

IPL, Minnesota Power, OTP and Xcel argue that MISO charges are sufficiently related to energy costs to warrant recovery of these costs through the fuel clause adjustment (FCA). Whereas a utility cannot change its "base rates" without undergoing a general rate case addressing all of the utility's costs and revenues, the FCA permits monthly adjustments to a utility's rates to reflect changes in the utility's energy-related costs.[11] These adjustments take effect without prior Commission review, but are subject to retroactive revision upon further investigation, and are reviewed in the utility's annual automatic adjustment filings (AAA).[12]

D. Prior Commission Orders

The Commission has issued three Orders addressing the utility's petitions for cost recovery.

1. The April 7, 2005 Order

Although the Commission had not yet had sufficient opportunity to evaluate the parties' arguments, on April 7, 2005, the Commission provided temporary relief by permitting the parties to recover Day 2 costs through the FCA on an interim basis subject to refund.[13]

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[10] Since the start of this docket, MISO had instituted additional charge types intended to reflect Control Area costs. No party has yet proposed recovery of these charge types, so they will not be addressed here.

[11] Minn. Rules pt. 7825.2400.

[12] Minn. Rules pt. 7825.2810.

[13] This docket, ORDER AUTHORIZING INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, SUBJECT TO REFUND WITH INTEREST (April 7, 2005).

2. The December 21, 2005 Order

After further analysis, on December 21, 2005, the Commission concluded that only certain costs should be recovered through the FCA. In particular, the Commission concluded that the costs of administering the Day 2 Market listed in Schedule 16 and 17 were insufficiently related to energy or to the types of costs previously recovered through the fuel clause to warrant FCA recovery. The Commission ordered the utilities to refund the balance to ratepayers.[14]

In addition, the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO and the Day 2 Market. In an effort to bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded to the same account. Because these two conceptual transactions would tend to cancel each other, the utility's records would reflect the net, or actual, cost or revenue from the operations.

Finally, the Commission proposed an investigation into the best methods for assuring low-cost electricity in Minnesota.[15]

3. The February 24, 2006 Order

On reconsideration, Commission granted all parties additional time in which to address the cost-recovery issue while also reducing the regulatory risk faced by the utilities. By Order dated February 24, 2006, the Commission suspended the refund obligation and restored the utilities' authority to continue recovering all Day 2 costs through the fuel clause. While this recovery remained interim subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring these costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[16]

To facilitate that analysis, the Commission directed the parties to develop a joint recommendation on the following:

A. Which of MISO's 32 charge types should the utilities recover through the fuel clause and which should they recover through base rates, with special attention to –

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[14] This docket, ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION (December 21, 2005 Order).

[15] December 21, 2005 Order at Ordering Paragraph 10.

[16] This docket, ORDER ON RECONSIDERATION SUSPENDING REFUND, GRANTING DEFERRED ACCOUNTING AND REQUIRING FILINGS at 7-8.

- the four uplift charges (Revenue Sufficiency Guarantee charge, Option B Uplift charge, Uncollectible Default Accounts and Real-Time Revenue Neutrality Uplift),
- Schedule 16 and 17, and
- Congestion revenues and expenses.

B. How to allocate MISO charges between retail and wholesale operations.[17]

The Commission also directed the utilities to provide information regarding the following:

A. The margin between cost and revenues generated by transactions with entities other than retail customers (that is, wholesale margins), and the resources a utility uses to generate them.

B. The level of wholesale revenues and related expenses for 2005.

C. The level of wholesale revenue or margin approved in the utility's most recently approved rate case and how these amounts were calculated in that case.[18]

II. Joint Report as Supplemented by November 6, 2006 Comments

The Joint Report reflects the parties' efforts to address these questions and to propose appropriate regulatory treatment for Day 2 costs and revenues; the Joint Report was supplemented by comments filed on November 6, 2006.

The Joint Report reflects the views of all parties except the RUD-OAG. In brief, the Joint Report recommends that the Commission authorize utilities to recover most Day 2 costs via their fuel clauses. In support of this proposal, the utilities agree to make certain commitments, described further below.

A. Use of Base Rates and Fuel Clause for Cost Recovery

In Exhibit B the Joint Report defines each of MISO's 32 charge types, divided into seven functional categories. After a thorough analysis, the Joint Report proposes permitting utilities to use the fuel clause to recover costs associated with six of the seven categories of charge types; only administrative charges would be reserved for possible recovery via base rates.

1. Fuel Clause

As noted above, all parties except RUD-OAG ask the Commission to find that the fuel clause provides an appropriate mechanism for recovery of most net MISO Day 2 costs. In sum, these parties argue that most of MISO's charge types identify costs that the parties were already recovering through the fuel clause.

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[17] *Id.*

[18] *Id.*

According to the Joint Report, for example, utilities bore the cost of transmission congestion long before MISO began to label and measure it. As noted above, if the transmission lines connected to a utility's least-cost generator are already full, the utility must rely on a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. In essence, the cost of congestion can be understood as the difference between the cost of relying on the high-cost generator and the low-cost generator. Prior to the emergence of MISO, the utility would simply characterize this cost as part of the cost of energy used at the substitute generator, and would recover this cost through the fuel clause. The Joint Report recommends continuing to let utilities recover this cost through the fuel clause, even though MISO now characterizes it as a congestion cost rather than a fuel cost.

The parties ask the Commission to authorize the recovery of Day 2 costs incurred since the Day 2 Market opened. In the interest of stability, the parties further ask the Commission to authorize the utilities to continue using the fuel clause to recover these costs for at least the next three years.

2. Base Rates

On the other hand, the Joint Report characterizes "Schedule 16 and 17 costs" as reflecting the costs of administering MISO. These costs do not correlate to the types of costs that had previously been recovered through the fuel clause, and the relationship between these costs and energy is more attenuated. Consequently the Joint Report does not recommend permitting parties to recover these costs through the fuel clause. Instead, the Joint Report recommends permitting a utility to have an opportunity in its next rate case to request recovery of these administrative costs through base rates.

Specifically, the Joint Report proposes that the Commission permit the utilities to defer all Schedule 16 and 17 costs incurred since the start of the Day 2 Markets. This deferral would continue without interest until the earlier of the utility's next electric rate case or March 1, 2009. By March 1, 2009, the utility would begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until the utility has a rate case addressing the utility's proposal for recovering the balance. The parties also recommend permitting a utility to begin recovering Schedule 16 and 17 costs when implementing interim rates at the start of a rate case; these rates are subject to refund if the utility cannot persuade the Commission that the utility deserves to recover the costs.

Ultimately, recovery of any administrative costs from ratepayers would depend on the utility having a timely rate case and demonstrating that the costs were prudently incurred, were reasonable, were not already recovered through other rates, and resulted in benefits justifying recovery.[19] In their Joint Report, the parties identify both costs and benefits arising from Day 2 operations.

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[19] The Commission has already authorized Xcel to recover some Schedule 16 and 17 costs through its base rates. *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase its Rates for Electric Service in Minnesota*, Docket No. E-002/GR-05-1428, FINDING OF FACTS, CONCLUSIONS OF LAW, AND ORDER; ORDER OPENING INVESTIGATION (September 1, 2006) (the Xcel rate case).

B. Allocating MISO Charges Between Retail and Wholesale Operations.

Joint Report Exhibit C provides recommended formulas for allocating a utility's bill for each charge type among the utility's native load, asset sales and trading (non-asset) sales. The exhibit also contains a illustrative example. A reformatted version of the exhibit is attached to this Order.

C. Allocation of Wholesale Margins

Joint Report Exhibit E reports on each utility's costs and revenues from trading electricity with entities other than their native load customers.

Since its last rate case, IPL has used the margins it earns on wholesale transactions to offset other costs in the fuel clause.[20] Similarly, Xcel has proposed a method for sharing revenues for both asset-based margins (net proceeds of wholesale sales of electricity and ancillary services produced from the utility's excess capacity for generation or long-term power contracts) and non-asset margins (net proceeds of wholesale sales of electricity acquired from other sources).[21] Minnesota Power and OTP propose to address the allocation of their wholesale margins in their next rate cases.

III. Position of RUD-OAG

RUD-OAG renews its objections to the Commission acting on the proposal to permit recovery of Day 2 costs via the fuel clause. RUD-OAG's concern arises from the fact that MISO is a federally-regulated entity which characterizes virtually all generation as a sale into the federally-regulated energy market, and virtually all consumption of electricity as a purchase from that market. Because federal law can preempt state law, RUD-OAG fears that FERC or a court may conclude that MISO's federally-approved tariff would preclude the Commission from continuing to regulate retail electric service in Minnesota.

RUD-OAG suggests that a case pending in Illinois[22] illustrates these concerns. In 1997 Illinois restructured its electric industry, permitting electric utilities to sell their power plants or transfer them to unregulated affiliates; at the same time, Illinois barred changes in electric rates for ten years. Utilities sold some plants, and some utilities began purchasing at wholesale the electricity needed to serve their native load customers. With the rate freeze ending, these Illinois utilities are now arguing that retail electric rates should be set based on the price of electricity in the wholesale market under FERC jurisdiction.

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[20] *In the Matter of a Petition by Interstate Power and Light Company for Authority to Increase Electric Rates in Minnesota*, Docket No. E-001/GR-03-767, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER; ORDER MODIFYING SETTLEMENT (April 5, 2004).

[21] Xcel rate case.

[22] *Commonwealth Edison et al.*, Illinois Commerce Commission Docket Nos. 05-0159, 05-0160, 05-0161, 05-0162.

Except for these jurisdictional concerns, RUD-OAG expresses no opinion about the rest of the Joint Report.

IV. Commission Action

The Commission appreciates the work of the parties to this docket in developing the Joint Report. The additional time given to analyzing these matters has helped all parties, and this Commission, better understand the purposes for and relationships among the charge types, and the functioning of the MISO Day 2 operation generally. While the RUD-OAG does not support the Joint Report, it does not object to its substance.

The Commission previously concluded that Schedule 16 and 17 administrative costs are not sufficiently related to energy costs to warrant recovery through the fuel clause. With the issuance of the Joint Report, no party now opposes this view. Utilities should be free to seek recovery of Schedule 16 and 17 costs in the same manner that they seek recovery for most other costs: through base rates established in a rate case. In the meantime, the Commission will authorize deferred accounting for these costs.

Otherwise, the Commission is persuaded that MISO Day 2 costs are sufficiently related to energy costs to warrant cost recovery via the fuel clause. As the Joint Report shows, Day 2 costs are generally the same types of costs that utilities have traditionally recovered through the fuel clause, merely identified with greater precision. The Commission will grant the parties' request to ratify recovery since the start of the Day 2 market, and to approve recovery prospectively for the next three years.

The Commission has previously heard and addressed RUD-OAG's jurisdictional concerns.[23] The Commission is not persuaded that RUD-OAG's citation to the case pending in Illinois provides any further basis for concern in Minnesota because of the regulatory differences between the two jurisdictions. Minnesota has not restructured its electric industry so the circumstances in Illinois are readily distinguishable from the circumstances here.

The Commission is mindful of its statutory charge to protect retail customers and of the need to guard against any erosion in its ability to fulfill that charge. Throughout these and earlier proceedings, the Commission has permitted Minnesota utilities to participate in MISO on the condition that the utilities would comply with accounting and operational standards designed to safeguard those protections. The Commission will continue to take all measures necessary to fulfilling its duty to ensure safe, adequate and reliable retail service throughout the state at just and reasonable rates.

Accordingly, the Commission will authorize MISO cost recovery only on the condition that parties accept and adopt practices designed to 1) ensure just and reasonable rates, 2) protect Minnesota's legal jurisdiction and 3) facilitate Commission oversight. These safeguards are set forth below.

[23] December 21, 2005 Order at 10-13 and Ordering Paragraphs 4 and 6.

A. Ensuring Just and Reasonable Rates

1. Use of Lowest-Cost Source of Energy

Consistent with prior Orders and longstanding utility practice, the Commission will direct each petitioner to use its lowest cost generation or resource to serve its ratepayers. The Commission sets retail rates based in part on a utility's cost to provide service; by requiring utilities to use their lowest-cost sources of energy to serve their native load ratepayers, the Commission can better ensure that ratepayers pay no more than the reasonable rate for service.

2. Refund of Schedule 16 and 17 Costs Collected through the FCA

The Commission previously authorized the utilities to recover Day 2 costs though the fuel clause, but only on an interim basis pending further analysis of the issues. Having now concluded that the fuel clause does not provide an appropriate means for recovering Schedule 16 and 17 administrative costs, the Commission will direct the utilities to refund these sums to ratepayers.

Specifically, the Commission will direct the utilities to disburse the funds through the fuel clause, reducing the amount customers would otherwise pay for each kilowatt-hour of electricity. While paying the refund out promptly would provide the quickest remedy, the Large Power Intervenors note that this procedure would provide disproportionate benefits to customers that consume disproportionate amounts of electricity during the winter. To avoid this weather bias and better direct the refund to the customers that have paid the Schedule 16 and 17 costs, the Commission will direct the parties to distribute the refund throughout the course of a year.

Of course, the calculation and disbursement of refunds will vary somewhat from utility to utility. Because Xcel partially addressed this issue in its most recent rate case, Xcel's obligation to refund Schedule 16 and 17 costs will pertain only to costs recovered from April 1 to December 31, 2005, the date Xcel's new rates took effect.[24] Moreover, while electric utilities generally calculate the amount to recover through the FCA based on the amount of energy costs actually incurred in prior months, the Commission has authorized Xcel to calculate its FCA based on forecasts of fuel-related costs for the coming month.[25] For purposes of Xcel's forecasted fuel clause and true-up calculations, therefore, the refunds for 2005 Schedule 16 and 17 charges should be reflected in the forecasted monthly adjustment, subject to audit and correction (true-up) in a manner similar to the other costs included in Xcel's fuel clause.

To calculate OTP's fuel clause true-up, on the other hand, the refunds for Schedule 16 and 17 charges should be reflected in the calculations for the periods during which they are made. The refund of Schedule 16 and 17 charges should not alter prior true-ups, including the true-up that OTP is currently implementing.[26]

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[24] Xcel rate case; Xcel's interim rates took effect January 1, 2006.

[25] *In the Matter of a Request by Northern States Power Company for Approval to Amend the Terms of its Electric Fuel Clause Adjustment Rider*, Docket No. E-002/M-00-420, ORDER (June 27, 2000).

[26] See *In the Matter of Otter Tail Power Company's Petition for Approval of a Fuel Clause Adjustment True-up Mechanism*, Docket No. E-017/M-03-30.

3. Sharing the Benefits of the Wholesale Market

In discussing the costs and benefits of the Day 2 market, MISO and the utilities claim that the market's efficient price signals and low transaction costs facilitate sales of electricity between electric utilities. As noted above, both IPL and Xcel have elected to use some or all of the benefits of these wholesale transactions to help defray the operational costs borne by their ratepayers. Minnesota Power and OTP offer, in their next rate cases or earlier if warranted, to address the extent to which the proceeds from their wholesale transactions should help underwrite their operating costs. Because this proposal is consistent with the Commission's duty to ensure reasonable rates, it will be accepted.

4. Virtual Transactions

Unexpected changes in supply or demand can cause the price of electricity in the Real-Time Market to fluctuate widely. The Department previously recommended, and the Commission previously ordered, utilities to limit their exposure to such price fluctuations when acquiring electricity for retail customers.[27] Parties now agree that virtual energy transactions may warrant similar concern.

"Virtual energy transactions" include, for example, a utility's offer in the Day-Ahead Market to buy electricity in the Real-Time Market for which the utility has no need, or to sell electricity for which the utility has no supply. Such transactions can be used to help a utility avoid the risk of price fluctuations in the Real-Time Market, a purpose arguably related to serving ratepayers. These transactions can also be used to speculate on market fluctuations, a purpose arguably unrelated to serving ratepayers. Because these transactions have these dual purposes, the parties agree that they merit special attention.

To this end, the utilities agree to include as part of their monthly FCA report a summary of all virtual energy transactions that affect the fuel clause. The Commission finds merit in this practice, and will accept the utilities' offer to provide it.

In addition, the Commission will limit the use of virtual transactions. First, the Commission will direct the utilities to use the strategy only to reduce risk or minimize costs assigned to retail customers. Utilities should not expose retail customers to market risks for purely speculative purposes.

Moreover, each utility agrees to strive to limit the use of virtual transactions that affect the FCA to 10% of total megawatt-hours (MWh) subject to the FCA. For any month in which a utility would exceed the 10% threshold, the utility would include in its FCA filing an explanation of its rationale for doing so. This threshold would not apply to virtual transactions that had no bearing on the FCA, such as when a utility engaged in virtual transactions related to non-asset based trading. In making this proposal, the parties acknowledge that the 10% threshold is a negotiated figure based on current market experience, and may warrant revision in the future.

Given the agreement of the parties, the Commission will approve these limitations on virtual energy transactions. The Commission may review and reset the 10% target as all parties gain greater experience with the Day 2 market.

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[27] December 21, 2005 Order at Ordering Paragraph 5.

B. Defending Commission Jurisdiction

1. Challenging FERC Preemption

The utilities acknowledge the Commission's duty to protect retail customers, and therefore to protect its authority to do so. Consequently, as a condition of receiving permission to recover Day 2 costs via the fuel clause the utilities commit to opposing FERC actions that would preempt the Commission's jurisdiction. Specifically, the utilities agree to challenge, both at the administrative level and throughout any judicial appeals, any FERC action that would require any of the utilities to purchase energy to serve native load customers at LMP market clearing prices without the offset arising from net accounting. Similarly, the utilities agree to challenge any action that would preclude the utilities from netting payments and credits for electricity the utility generates or purchases under contract against the LMP payments made by retail load, as currently occurs under the MISO Day 2 tariff.

The Commission finds that the utilities' offer will help the Commission fulfill its statutory duties. Moreover, the offer demonstrates the utilities' good faith in seeking their legitimate interest in recovering energy-related costs without seeking any ancillary goal of evading state regulation. The utilities' offer will be accepted.

2. Revocation of Cost Recovery

As noted above, RUD-OAG argues that granting the utilities the authority to recover Day 2 costs through the fuel clause could cause the Commission to lose authority to regulate aspects of retail service in Minnesota. The Department, the utilities and other parties reach the opposite conclusion, and the Commission has found insufficient support for RUD-OAG's position. Consequently the Commission is proceeding based on the legal conclusion that it may continue to exercise its full authority to promote ratepayer interests with respect to all aspects of retail electric service while also granting the utilities' petitions to recover certain Day 2 costs through the fuel clause.

Because this conclusion represents a fundamental basis for the Commission's decision, however, any change in that conclusion would require reconsideration of this Order. Acknowledging that contingency, the Commission finds that it would have to withdraw its approval of the utilities' use of the FCA for Day 2 costs recovery if any of the following events were to occur:

- FERC issuing a final decision and order having the effect of requiring Minnesota utilities to purchase energy to serve native load customers in whole or in part at LMP market clearing prices.
- FERC taking any action that would prevent utilities from netting payments and credits for owned generation or contracted purchases against the LMP payments made by retail load.
- FERC taking any other action preventing any utility from using its lowest cost generation or resource to serve its native load ratepayers.

The utilities concede that the Commission may need to take this step to safeguard consumer protections. However, they ask that the Commission permit cost recovery to continue for a reasonable period following any relevant FERC action to provide an adequate opportunity for legal analysis and to permit an orderly transition. The Commission finds merit in this request. Accordingly, the Commission will suspend the revocation until 60 days after the effective date of any FERC action in question.

3. Accounting Practices

In its December 21, 2005 Order, the Commission specified how the utilities should record Day 2 costs for purposes of 1) clarifying the distinction between serving native load customers and serving the wholesale or "off-system" market, and 2) facilitating analysis of Day 2 operations for prudence.[28] The parties generally recommend continuing these practices but with a few refinements. Specifically, the parties propose that each petitioning utility do the following:

- Record each transaction to a separate sub-account of Accounts 447 (Sale for Resale) and 555 (Purchased Power).
- Record to Account 555 on an aggregated basis any revenues and costs linked to MISO's Day 2 locational marginal pricing, 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.
- Use net accounting for purchases and sales for owned generation facilities.
- Continue to use Accounts 151 (Fuel Stock) and 501 (Fuel) to record fuel costs related to generation plants serving native load, the same way they are accounted for today.
- Continue to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
- Track in a separate sub-account each MISO charge and revenue.
- Allocate all MISO Day 2 charges pursuant to the formulas set forth in the Joint Report's Exhibit C.

Because these accounting practices will help clarify the true nature of a utility's operations, especially retail operations, the Commission will approve them.

C. Facilitating Oversight

1. Reporting

As a condition of granting utilities permission to recover Day 2 costs through the FCA, the December 21, 2005 Order also directed utilities to expand the monthly FCA reports as well as the annual AAA reports. The Commission ordered utilities to report on the sum of various charge types that the Commission associated with the cost of energy or inter-system sales, for example, and to contrast the amount of each charge type expense incurred to serve retail customers with the

[28] *Id.*, Ordering Paragraph 6.

amount incurred to sell power outside the utility's system.[29] In addition, the Commission directed each utility to report on the network resources that the utility offers for MISO to use to serve the system's aggregate needs.[30]

Again the parties recommend continuing these practices generally, but in a manner that reflects an increased understanding of charge types and system dynamics. The Commission will accept these recommendations as modified below. These new FCA reporting requirements will supplement the utility's filing and reporting requirements under the Commission's FCA rules, the current monthly and annual AAA review process of FCA costs, and the currently accepted standard of review for recovery of fuel and purchased energy costs. The Commission may scrutinize the utility's actions reflected in these FCA reports and bar recovery of any imprudently incurred costs.

a. Additional AAA Filing Requirements

An electric utility's AAA report already contains estimates of how the cost of each of the utility's fuel sources will change each year for the next five years, and each month for the next two years.[31] In addition to this requirement, each utility agrees to file as part of its electric AAA report certain information regarding its plans with respect to acquiring fuel and purchased energy.

Network resources dedicated to native load. To demonstrate that it is using its lowest cost sources of energy to serve its native load customers, each utility agrees to identify and update the list of network resources that it dedicates to that purpose.

Summary of factors affecting cost. Each utility agrees to prepare a summary of its AAA filing stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs).

Plans for minimizing fuel costs. Each utility agrees to include in its AAA report an overview of anticipated events and planned actions to address fuel clause costs, and steps the utility plans to take to minimize or lower such costs when possible. Each utility will provide a discussion of tools for managing fuel clause costs. This discussion will include plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels. It will include plans to hedge purchased energy costs through forward bilateral purchases or financial instruments, including how the utility would plan for and cover fuel and energy risk during planned unit outages. And it will include, where appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of Financial Transmission Rights in the Day 2 Market. By preparing this filing, the utilities expect to gain sufficient flexibility to respond to changing market conditions.

Opportunity for review and public participation. The utilities agree that this expanded AAA process will provide an opportunity a) for review and audit of each utility's plans for mitigating fuel costs, b) for review of congestion costs and revenues, and c) for customers to intervene for

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[29] *Id.*, Ordering Paragraph 7.

[30] *Id.*, Ordering Paragraphs 4 and 7.A.

[31] Minn. Rules pt. 7825.2830

purposes of seeking a technical review or audit of utility's fuel and energy costs to evaluate the prudence of the utility's actions in the energy market. The utilities reserve their rights, however, to ask parties to sign agreements protecting the confidentiality of utility data before such an audit would begin.

b. Forecasting

Annual FCA Forecast. To provide additional help to customers seeking to manage their energy costs, the petitioning utilities now propose to provide an annual FCA forecast of fuel and purchased power costs per MWh for the coming 12 months. This FCA Forecast would address all fuel and energy costs associated with the operation of a utility's system, in addition to projected MISO Day 2 costs and revenues. The FCA Forecast would identify major changes that could affect the stability of the forecast. The FCA Forecast would also address projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Where the forecast deviates from the utility's energy costs for the prior year, the utility will explain the deviation.

While the utilities plan to file such forecast annually, they agree to revise their FCA Forecasts whenever deviations from the current forecast are sufficiently material to warrant revision for the coming twelve months.

The utilities agree to make the FCA Forecast available to customer representatives who sign a protective agreement governing disclosure of confidential information, and to strive to provide timely responses to their questions. Each utility would meet with interested parties to discuss the FCA Forecast, the utility's progress in achieving the FCA Forecast, and any new proposals in the MISO Day 2 Market.

Monthly FCA Forecast. In addition to the annual FCA Forecast, each utility proposes to prepare a fuel and purchased energy forecast for each monthly FCA filing. The utilities agree to endeavor to file these forecasts three days before the first day of the FCA billing month.

To promote accountability, whenever a utility's monthly fuel and purchased energy forecast exceeds the budget for that month set forth in the then-current FCA Forecast by more than 10%, the utilities agree to provide an explanation of the causes for this change.

To further promote accountability, whenever a utility's forecast of fuel and energy costs for a month deviated from actual fuel and energy costs by 15% or more, the utility would prepare an explanation quantifying the major reasons such as unit outages, congestion costs, weather, and fuel price changes. The utility would explain how it can control these costs and identify the extent to which the utility is unable to control these costs.

In addition to these proposals, the Commission will direct the Department to report promptly to the Commission whenever, for any three month period, a utility forecast has deviated from actual costs by 15% or more.

2. Investigations

a. Assuring Low-Cost Electricity

The Joint Report, and the proceedings that led to it, provide new perspective on how electric utilities will operate in this evolving environment, but the Day 2 market is still in its infancy.

Given the consequence of this market for Minnesota utilities and their customers, the Commission must remain abreast of developments in this arena. Consequently the Commission will initiate two investigations.

First, the Commission reasserts its intention to investigate the best methods for assuring low-cost electricity in Minnesota.[32] While all parties will have an opportunity to comment on the precise scope of the investigation, and to participate in a technical conference or forum on the selected topics, the investigation will evaluate at least the following options:

- The formation of a transmission-only entity for Minnesota, perhaps modeled on the American Transmission Company, LLC.[33]
- The formation of a more regional transmission company or regional transmission organization incorporating facilities in neighboring states and Canadian provinces, perhaps modeled on the Mid-Continent Area Power Pool.
- The development of alternatives for Minnesota utilities to pursue low-cost electricity, including the opportunity – but not the obligation – to buy and sell electricity in wholesale markets.

b. Reviewing the Consequences of Day 2 Operations

In addition to this wide-ranging investigation, the Commission will also require a somewhat more focused review, but require that it be conducted by a date certain. Specifically, the Commission will require a comprehensive review of the consequence of MISO Day 2 operations on Minnesota ratepayers and recommendations for changes as appropriate. The Department has agreed to conduct this analysis, and asks that utilities provide the relevant information through their AAA reports due each September 1.

The utilities claim that they have experienced fewer problems during the second year of Day 2 operations than during the first, and that they hope for increasingly smooth operations in the future. Consequently the Department recommends that the Commission delay evaluating – and perhaps modifying – its Day 2 policies until all parties have gained a few more years of experience in the market.

The Commission appreciates the Department's offer to conduct the review, and finds merit in the suggestion to provide all parties with the benefit of additional experience before seeking to re-evaluate the situation. The Commission will therefore direct the Department to provide its report by February 2009. The Department asks that the utilities provide all relevant data as part of their AAA filings by September 1, 2008.

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[32] December 21, 2005 Order at Ordering Paragraph 10.

[33] Electric utilities in eastern Wisconsin and contiguous areas of adjoining states contributed roughly 8900 miles of transmission lines to form the American Transmission Company, a transmission-only electric utility. It joined MISO in 2002. *American Transmission Company LLC*, 97 FERC ¶ 62,182 (2001).

With the benefit of these analyses, the Commission may be assured that it has fulfilled its statutory charge to oversee the provision of crucial utility services within Minnesota.

D. Conclusion

For the foregoing reasons, the Commission will adopt the recommendations of the Joint Report as supplemented by the comments of November 6, 2006, and as modified herein. With safeguards in place to ensure reasonable rates, protect Minnesota's legal jurisdiction and facilitate oversight, the Commission will grant deferred accounting treatment with respect to Schedule 16 and 17 costs, and will authorize recovery the rest of the prudently incurred Day 2 costs through the fuel clause.

The Commission will so order.

ORDER

1. Except as regards Schedules 16 and 17 costs, discussed below, each petitioning utility 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 the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of this Order.

2. Each petitioning utility may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005. Each utility may continue deferring Schedule 16 and 17 costs without interest until the earlier of the utility's next electric rate case or March 1, 2009. By March 1, 2009, the utility shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until the utility has a rate case addressing the utility's proposal for recovering the balance.

3. In its next rate case a utility may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. The utility 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, a utility 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 each utility 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 except as provided below.

    A. Xcel shall refund through the FCA all Schedule 16 and 17 costs previously recovered through the FCA from April 1 to December 31, 2005, prior to the effective date of interim rates in the Xcel rate case. For Xcel, the refund amount shall be added to the Schedule 16 and 17 costs subject to deferred accounting as provided in the Xcel rate case to establish the total deferral balance.

    B. For the purposes of Xcel's forecasted fuel clause and true-up calculations, the refunds for 2005 Schedule 16 and 17 costs shall be reflected in the forecasted monthly adjustment, subject to true-up in a manner similar to other costs included in the Xcel fuel clause.

C. 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, including the true-up that OTP is currently implementing.

5. Virtual Energy transactions in the Day 2 market are subject to the following conditions:

A. The utilities 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. Utilities 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 Department.

C. The utilities 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 by any utility in any particular month, subject to the requirement that the utility 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. Each petitioning utility 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. Each petitioning utility shall provide to the Department the following additional reporting requirements in their monthly FCA reports and AAA reports:

A. Each utility shall file as part of its electric AAA report certain additional information regarding its plans with respect to acquiring fuel and purchased energy.

1) Each utility shall include in its AAA report an overview of its anticipated events and planned actions to address fuel clause costs, and the actions planned by the utility to minimize or lower such costs whenever possible. Each utility 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 the utility 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) These plans are subject to annual review and audit in the AAA process. Congestion costs and revenues shall be reviewed in an annual filing. In addition, in the AAA review process customers may petition to intervene and seek either a technical review or, pursuant to appropriate protective agreements, be allowed to conduct an audit of utility's fuel and energy costs to review the prudence of the utilities' actions in relation to the market.

3) Each utility 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, each utility shall submit 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 the utility'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 the utility'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, each utility shall explain the reasons for deviations in forecasts from actual costs in the previous year.

C. Each utility shall prepare a summary of its AAA filing stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast. A utility 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. The FCA Forecast shall be shared with customer representatives who sign a protective agreement. A copy of the revised FCA forecast shall also be provided to the Department. Each utility shall attempt to respond in a timely manner to questions from customers who have signed a protective agreement.

D. Each utility shall meet with interested parties to discuss the FCA Forecast, the utility's 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. Each utility shall prepare fuel and purchased energy forecasts for each monthly FCA filing, which the utility shall endeavor to file 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%, the utility shall provide an explanation of the cause(s) of this change.

F. In the event that the utility's forecast of fuel and energy costs for a month deviates from actual fuel and energy costs by 15% or more, the utility shall prepare a monthly deviation explanation quantifying the major reasons such as unit outages, congestion costs, weather, and fuel price changes. The utility shall explain how it can control these costs, or the extent to which it is unable to control these costs. The Department shall report to the Commission promptly when, for any three-month period, a utility forecast has deviated from actual costs by 15% or more.

G. Each utility shall use the monthly FCA reporting format as set forth in the Joint Report's Exhibit D, attached in revised form (with minor variations as allowed by the Department), listing each Day 2 charge type grouped into seven categories and providing cumulative data for the calendar year.

H. Each utility shall supplement its monthly fuel clause report to the Department with information on significant events affecting that month's fuel clause costs.

8. Minnesota Power and OTP shall each address wholesale revenue margin sharing issues no later than the time of each utility's next rate case, or earlier should events warrant.

9. Each petitioner shall use its lowest cost generation or resource to serve its ratepayers.

10. The utilities shall challenge, both at the administrative level and through appeal if necessary, any FERC action that would require any of the utilities 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 Order shall terminate 60 days after the effective date of any FERC final decision and order having the effect of requiring Minnesota utilities to purchase energy to serve native load customers in whole or in part at LMP market clearing prices, action that would prevent utilities from netting payments/credits for owned generation or contracted purchases against the LMP payments made by retail load, or any other action preventing any utility from using its lowest cost generation or resource to serve its native load ratepayers.

12. The Commission will open an investigation into the best methods for assuring low-cost electricity in Minnesota. As part of that investigation, the Commission will do the following:

    A. Solicit comments on the appropriate scope for this new docket.

    B. Solicit comments on the following alternatives:

1) Forming, by state law, a statewide transmission company.

2) Forming a regional transmission company or regional transmission organization incorporating facilities in Manitoba, Minnesota, North Dakota, South Dakota and Wisconsin, perhaps modeled on the Mid-Continent Area Power Pool.

3) Developing alternatives for Minnesota utilities to pursue low-cost electricity, including the opportunity – but not the obligation – to buy and sell electricity in wholesale markets.

C. Convene a technical conference/forum on the topics identified to be within the investigation's scope.

13. By February 2009 the Department shall conduct a comprehensive review of the consequence of MISO Day 2 operations on Minnesota ratepayers and shall recommend changes as appropriate. Petitioners shall provide relevant data to the Department in their AAA reports due September 1, 2008.

14. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)

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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 Cinergy Hub as a Trading Sale. The LMP at Cinergy was $35/MWh and the LMP at Minnesota was $31/MWh. The company was responsible for congestion and losses from Minnesota Hub to Cinergy 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.
Otter 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)	DA Generation (LMP x MWh)	DA Fin Sched (LMP x MWh)	Direct assignment using calculations noted.
		($28/MWh x 700MWh) + ($30/MWh x -1000MWh) + ($30/MWh x 200MWh) = -$4400 [1, 2, 4]	$28/MWh x 100MWh) = $2800 [2]	Not illustrated.	
3	DA Fin Sched Losses	DA Fin Sched (LMP_{L1} - LMP_{L2}) x MWh	N/A	DA Fin Sched (LMP_{L1} - LMP_{L2}) x MWh	Direct assignment using calculations noted.
		-$2/MWh x 200MWh = -$400 [4]	N/A	-$3/MWh x 50MWh = -$150 [5]	
5	DA Non-Asset Energy	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh)	N/A	DA Physical Schedule (LMP x MWh) + DA Fin Sched with node not belonging to Asset Owner (LMP x MWh)	Direct assignment using calculations noted.
		($26/MWh x 100MWh) = $2600 [3]	N/A	($35/MWh x 50MWh) + (-$35/MWh x 50MWh) = $0 [5]	
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_{L1} - LMP_{L2}) x MWh	N/A	RT Fin Sched (LMP_{L1} - LMP_{L2}) x MWh	Direct assignment using calculations noted.
22	RT Non-Asset Energy	RT Phyical 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.
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 Physical Schedule (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.
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 noted.
Subtotal MISO Day 2 Charges					

Cost Allocation (continued)

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No.	Charge Type	Native Load	Asset Sales	Trading (Non-Asset) Sales	Method
	Congest & FTRs				
2	DA Fin Sched Congestion	Da Fin Sched (LMP_{c1} - LMP_{c2}) x MWh -$1/MWh x 200MWh = -$200 [4]	N/A N/A	DA Fin Sched (LMP_{c1} - LMP_{c2}) x MWh -$1/MWh x 50MWh = -$50 [5]	Direct assignment using calculations noted.
15	RT Fin Sched Congestion	RT Fin Sched (LMP_{c1} - LMP_{c2}) x MWh	N/A	RT Fin Sched (LMP_{c1} - LMP_{c2}) x MWh	Direct assignment using calculations noted.
28	FTR Hourly Allocation	FTR Receipts [Prorating Factor x (LMP_{c2} - LMP_{c1} when difference is positive)] + FTR Payments (LMP_{c2} - LMP_{c1} when difference is negative)	FTR Receipts [Prorating Factor x (LMP_{c2} - LMP_{c1} when difference is positive)] + FTR Payments (LMP_{c2} - LMP_{c1} when difference is negative)	FTR Receipts [Prorating Factor x (LMP_{c2} - LMP_{c1} when difference is positive)] + FTR Payments (LMP_{c2} - LMP_{c1} 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 calculations.
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 calculations.
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 calculations.
11	DA RSG Make Whole Payment	DA Committed Gen (MWh)	DA Committed Gen (MWh)	N/A	Allocate using the quantities determined in the calculations.
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 calculations.
25	RT RSG Make Whole Payment	N/A	All assigned to asset sales.	N/A	Direct assignment using calculations noted.
	Revenue Neutrality Uplift				
23	RT RNU	Metered Load (MWh) + Physical Exports (MWh)	N/A	Physical Exports (MWh)	Allocate using the quantities determined in the calculations.
23a	UD Uplift	sub group of 23			
23b	JOA Uplift	sub group of 23			
23c	Carve Out Grandfathered Agreement Uplift	sub group of 23			
23d	Option B Grandfathered Agreement Uplift	sub group of 23			
23e	Real Time Revenue Sufficiency Guarantee Second Pass Uplift	sub group of 23			
23f	Revenue Inadequacy Uplift	sub group of 23			
	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 Uninstructed Deviation	Absolute Value of Generation Imbalance (MWh)	Absolute Value of Generation Imbalance (MWh)	N/A	Allocate using the quantities determined in the calculations.
	Grandfathered Charge Types				
6	DA Congestion Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
7	DA Loss Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
8	DA Congestion Rebate on Option B GFAs (OTP only)	All assigned to native load.	N/A	N/A	Direct assignment using calculations noted.
9	DA Loss Rebate on Option B GFAs (OTP only)	All assigned to native load.	N/A	N/A	Direct assignment using calculations noted.
17	RT Congestion Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
18	RT Loss Rebate on Carve-Out GFAs	N/A	N/A	N/A	N/A
	Subtotal MISO Day 2 Charges (from page 1)				
	Total MISO Day 2 Charges				

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	#DIV/0!	¢ / kHz

10 Fuel Adjustment Clause #17 :

Fuel Cost	-	
Less Base	-	
Fuel Adjustment	-	¢ / kHz

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 occu 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 Toivonen
Senior Accounting Analyst

MINNESOTA POWER MONTH: Apr-06

MISO MONTHLY ALLOCATION

Charge Type	Account Number	Total Apr-06	FAC Retail	FAC Resale	FAC Total	Non-FAC 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 Carve-Out Grandfathered Agrmnts	5551-0023					
Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	5551-0024					
Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	5551-0025					
Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	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 Carve-Out Grandfathered Agrmnts	5551-0039					
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	5551-0040					
Real Time Distribution of Losses Amount	5551-0041					
Real Time Miscellaneous Amount	5551-0042					
Real Time Net Inadvertent Distribution Amount	5551-0044					
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 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	November 2005	December 2005	Total
	Day Ahead & Real Time Asset & Non Asset Energy & Loss										
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Real Time Financial Bilateral Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Real Time Non Asset Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Virtual Energy										
12	Day Ahead Virtual Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real Time Virtual Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Schedules 16 & 17										
4	Day Ahead Market Administration (Schedule 17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Real Time Market Administration (Schedule 17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Financial Transmission Rights Administration (Schedule 16)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Congestion and FTRs										
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RSG & Make Whole Payments										
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Other Charges										
20	Real Time Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Real Time Net Inadvertent Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Real Time Revenue Neutrality Uplift Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Real Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Grandfathered Charges Types										
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Real Time Loss Rebate on Carve Out-Grandfathered	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total MISO Day 2 Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

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/]		-	

Concurring Opinion by Commissioner Ken Nickolai

I concur with the decision but feel it necessary to add some additional discussion.

Originally the fuel clause permitted electric utilities to recover the cost of wholesale power purchases made at rates that the Federal Energy Regulatory Commission (FERC) had found to be reasonable. Today, rates established through FERC's reasonableness review have largely been replaced by rates established in MISO's evolving energy market. It is too early to tell whether the results of this FERC-driven change will be beneficial to consumers, or whether automatic wholesale cost recovery will need to be revisited in the future.

I am persuaded by the authors of the Joint Report and Recommendation that the costs utilities now recover through the fuel clause are of the same type that utilities recovered through the fuel clause prior to the emergence of the MISO market. But that assurance does not address whether utilities retain adequate incentives to push back on MISO to keep the costs within reason – costs that previously were more under the control of each individual utility.

However, I am also convinced that to not allow the cost of wholesale energy through the fuel clause at this time would not be prudent. Barring the recovery of these costs through the fuel clause could affect the utilities' financial ratings and ultimately their cost of debt and equity capital – potentially substantial consequences for utilities and their customers that have not yet been addressed in this record. Further examination of those issues would be necessary before taking any steps to disallow automatic recovery of these costs.

I am very pleased that my colleagues have reaffirmed the need to investigate ways of ensuring low-cost electricity for Minnesota. The risks to Minnesota electric consumers arising from the MISO market as currently structured are substantial. Issues needing careful examination include the following:

- The means of ensuring adequate generating capacity within the boundaries of MISO's operations. To date, electricity markets have proven to be effective at pricing scarcity, but not at bringing new generation to the market. Planning reserve margins, which are an essential component of reliability and stable market prices, are no longer enforceable.

- Risk of bidding strategies. Each day utilities make decisions on their strategies for offering energy into the markets and purchasing energy from the markets. Use of the fuel clause allows the risk of those decisions to be automatically passed from the utilities to their consumers. Careful review is necessary to ensure that retail customers are being adequately protected from any adverse consequences of a utility's bidding strategy.

- Allocation of Financial Transmission Rights (FTRs). As discussed briefly in the Order, FTRs are the means by which Minnesota retail customers are protected from "congestion pricing" and resulting cost increases. To ensure protection of native load customers, MISO must provide utilities with a full allocation of FTRs. MISO has not always provided such allocations in the past. This allocation should be carefully watched in the future.

- Risk of cost shifting. The mechanisms by which costs incurred by MISO are allocated back to the customers of their member utilities needs to be carefully scrutinized. If programs undertaken by Minnesota utilities and consumers help reduce demand during times of peak demand, those utilities and customers should not have to bear the costs of acquiring expensive power to serve those who do not reduce their demand.

This list is not intended to be exhaustive, but to be indicative of the types of inquiry that are needed as we proceed to investigate how to enure the supply of least-cost electric energy for Minnesota customers.

In conclusion, while I concur in the decision, I urge my colleagues on the Commission and the representatives of the public at the Department of Commerce and the Residential and Small Business Utilities Division of the Office of the Attorney General to continue to provide active oversight for MISO's operations. We must carefully consider both whether the existing structure of the market is working as hoped for the Minnesota retail consumer, and to thoughtfully revisit the use of the fuel clause in the broader context of its potential financial consequences after there has been more experience with the MISO market.