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 21, 2005 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 SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION

PROCEDURAL HISTORY

On December 14, 2004, Northern States Power Company d/b/a Xcel Energy (Xcel) asked the Commission to find that the costs resulting from participation in the "Day 2" market operations of the Midwest Independent Transmission System Operator, Inc. (MISO) could be recovered from ratepayers though the use of Xcel's fuel clause adjustment (FCA). Xcel supplemented this request on February 11, 2005. By February 17, the Commission had received similar requests from Minnesota Power and Otter Tail Power (OTP).

By February 25, 2005, both the Minnesota Department of Commerce (the Department) and the Residential and Small Business Utilities Division of the Office of Attorney General (RUD-OAG) had filed comments expressing reservations about Xcel's petition. Xcel replied to these concerns on March 2.

On March 3, Interstate Power and Light Company (IPL) also petitioned to recover Day 2 Market costs though its FCA.

On March 17, 2005, the RUD-OAG filed comments on each of the petitions.

On April 7, 2005, the Commission issued its Interim Order granting the petitioners permission to begin recovering their MISO Day 2 Market costs through the FCA on an interim basis.[1] But the Commission specified that if it subsequently concluded that the FCA does not provide an appropriate mechanism to recover any of those costs, the petitioners would have to repay those sums with interest.

By July 22, 2005, the Department had filed comments on each of the petitions, and a group of industrial firms (the Large Power Interveners) had commented on Minnesota Power's petition. The Department supplemented its comments on the petitions of Minnesota Power, OTP and Xcel on July 25.

By August 1, 2005, the petitioners had filed reply comments in their respective dockets. OTP and Xcel replied to the Department's supplemental comments by August 19.

This matter came before the Commission on October 27 and November 3, 2005.

FINDINGS AND CONCLUSIONS

I. Background

A. Development of the electric transmission grid

Historically, most investor-owned electric utilities have been vertically integrated. That is, a utility generally built its own power plants to generate electricity, built its own transmission lines to transport its electricity over long distances, and built its own distribution lines to deliver electricity to its retail customers. Utilities would have both the opportunity and the duty to serve all customers within their service area.[2]

Service from such a stand-alone utility could be unreliable because the failure of any one power plant or transmission line could cause a local blackout. To reduce these risks, electric utilities have interconnected their systems. Interconnection permitted them to draw on a neighboring utility's capacities during emergencies, thereby enhancing service reliability throughout the transmission grid. Eventually most Minnesota utilities joined the Mid-Continent Area Power Pool (MAPP). During emergencies, Minnesota utilities could call upon the capacities of fellow MAPP members in this state, neighboring states and some Canadian provinces.

But interconnection produced benefits beyond increased reliability. For example, if Utility X has excess capacity on a generator with low operating costs, Utility Y may prefer to purchase electricity from Utility X rather than incur the cost of generating its own energy, and Utility X may prefer to sell that electricity rather than leave the excess capacity unused. Alternatively, Utility Y could purchase from the remote Utility Z, or even an electric generator unaffiliated with

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[1] This docket, Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest.

[2] See Minn. Stat. §§ 216B.37 - 216B.40.

a utility, and transmit the electricity across Utility Y's transmission lines. Where such opportunities arise, parties have negotiated "power purchase agreements," or bilateral contracts for the purchase and sale of electricity.

B. 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.[3] To facilitate regulation, FERC directs utilities within its jurisdiction to maintain records according to its Uniform System of Accounts.[4]

FERC encourages public utilities that own, operate or control interstate transmission facilities to join regional transmission organizations (RTOs).[5] 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."[6]

C. MISO and the Day 2 Market

The Minnesota Public Utilities Commission authorized IPL, Minnesota Power, OTP and Xcel to transfer operation control of transmission facilities to an RTO called the Midwest Independent Transmission System Operator, Inc. (MISO) for the purposes of achieving –

- "one stop" shopping for transmission services, without the need to negotiate and pay for the use of each utility's lines individually,
- the establishment of uniform and clear transmission usage rules,
- control over transmission facilities more clearly separated from the influence of electric market participants,
- large scale regional coordination and planning of new transmission construction,
- enhanced reliability, and
- a more competitive market for wholesale power.[7]

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[3] 16 U.S.C. § 824.

[4] 18 U.S.C. pts. 1-399.

[5] *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).

[6] 18 C.F.R. § 35.34(a).

[7] *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

MISO categorizes much of these activities as “Day 1" operations.

MISO has now initiated “Day 2” operations governed by its Open Access Transmission and Energy Markets Tariff (TEMT)[8] and associated "Business Practices Manuals." The TEMT recharacterizes the way in which utilities provide electricity for the customers they are obligated to serve (“native load customers”[9]), including retail customers. Traditionally the petitioners were understood to generate most of the electricity needed to serve their customers, and to buy or sell any surplus or deficit from their neighboring utilities. In contrast, the TEMT describes virtually all electric generation as a sale of electricity into a wholesale market, and describes the provision of electric service to include purchasing power back from the market.

According to the TEMT, the Day 2 Market encompasses both the “Day Ahead Market” and the “Real Time Market.” To participate in the Day Ahead Market, petitioners forecast where customers will be demanding electricity the next day, and the magnitude of the demand. Petitioners also designate the generators (“network resources”)[10] 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 as they arise. For example, unanticipated weather may change customer demand, or a mechanical failure may change the available supply.

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 the cheaper sources of power are already in use.

Sometimes MISO will be unable to use the system’s lowest-cost generators because doing so would require moving electricity through a transmission line that is already full. When such transmission constraints arise, the TEMT provides for dispatching generators connected to transmission lines with available capacity, even though the substitute generator 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 produces a locational marginal price

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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).

[8] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).

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

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

(LMP) for electricity. LMP reflects a fuel component (the cost of the fuel necessary to generate that last unit of power required on MISO's system to serve all customers' needs as if there were no congestion), a marginal congestion component (the added cost of providing that electricity at the specified location), and a marginal line loss component (the added cost of line losses that result from transmission).

Given transmission constraints, parties in bilateral contracts bear the risk that the low-cost source of electricity may not be allowed to run, and that a higher-cost generator will be dispatched instead. The TEMT 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.

D. MISO Charges

MISO began Day 2 market operations – the buying and selling of power – within the service area of its members[11] in April 2005.[12] Since then, MISO has begun accounting for revenues and expenses, and rendering bills, based on thirty-two "charge types," some further subdivided into components. The Business Practices Manuals lists these charge types as follows:

Day-Ahead Charge Types

1. Day-Ahead Asset Energy Amount (with energy, congestion, and line loss components)
2. Day-Ahead Financial Bilateral Transmission Congestion Amount
3. Day-Ahead Financial Bilateral Transaction Loss Amount
4. Day-Ahead Market Administration Amount
5. Day-Ahead Non-Asset Energy Amount
6. Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements
7. Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements
8. Day-Ahead Congestion Rebate on Option B Grandfathered Agreements
9. Day-Ahead Losses Rebate on Option B Grandfathered Agreements
10. Day-Ahead Revenue Sufficiency Guarantee Distribution Amount
11. Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount
12. Day-Ahead Virtual Energy Amount

Real-Time Charge Types

13. Real-Time Asset Energy Amount (with energy, congestion, and line loss components)
14. Real-Time Distribution of Losses Amount
15. Real-Time Financial Bilateral Transaction Congestion Amount
16. Real-Time Financial Bilateral Transaction Loss Amount
17. Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements

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[11] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163, *order on reh'g*, 109 FERC ¶ 61,157 (August 6, 2004).

[12] *Midwest Independent Transmission System Operator, Inc.*, Docket Nos. ER04-961-014 and EL04-104-013, *et al.* (March 16, 2005).

18. Real-Time Losses Rebate on Carve-Out Grandfathered Agreements
19. Real-Time Market Administration Amount
20. Real-Time Miscellaneous Amount
21. Real-Time Net Inadvertent Distribution
22. Real-Time Non-Asset Energy Amount
23. Real-Time Revenue Neutrality Uplift Amount
24. Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount
25. Real-Time Revenue Sufficiency Make Whole Payment Amount
26. Real-Time Uninstructed Deviation Amount
27. Real-Time Virtual Energy Amount

Financial Transmission Rights Charge Types

28. Financial Transmission Rights Hourly Allocation Amount
29. Financial Transmission Rights Market Administration Amount
30. Financial Transmission Rights Monthly Allocation Amount
31. Financial Transmission Rights Transaction Amount
32. Financial Transmission Rights Yearly Allocation Amount

A utility can attempt to audit the bills it receives from MISO by comparing them to the utility's own record of transactions, known as a "shadow settlement system."

IPL, Minnesota Power, OTP and Xcel now seek permission to recover their MISO Day 2 costs through the FCA. Neither this Commission nor FERC has determined the appropriate accounting treatment for such RTO costs. FERC has proposed rules to address this question,[13] but has not yet reached a decision. In the meantime, this Commission permitted the utilities to recover their net Day 2 costs through the FCA, with the understanding that the utilities would need to refund with interest any amounts that the Commission subsequently ruled should not be recovered in this manner.

E. Fuel Clause Adjustments

The petitioners ask to be permitted to recover their Day 2 costs through the fuel clause adjustment (FCA).

Generally a public energy utility may not change its retail rates unless it undergoes a general rate case wherein all of its costs and revenues are considered.[14] But the Minnesota Legislature has created exceptions to this policy. In particular, statute authorizes the Commission to permit an energy utility to adjust its rates outside the context of a general rate case to reflect changes in the cost of energy:

> [T]he commission may permit a public utility to file rate schedules containing

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[13] *Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators*, Docket No. RM04-12-000, Notice of Inquiry (September 16, 2004).

[14] Minn. Stat. §§ 216B.03, 216B.16; Minn. Rules pt. 7825.3100 *et seq*.

> provisions for the automatic adjustment of charges for public utility service in direct relation to changes in: (1) federally regulated wholesale rates for energy delivered through interstate facilities; (2) direct costs for natural gas delivered; or (3) costs for fuel used in generation of electricity or the manufacture of gas.[15]

Consistent with this statute, the Commission has adopted rules to permit utilities to adjust their rates to recover fuel costs through a process called the "fuel clause adjustment."[16] Specifically, the FCA rules permit utilities an opportunity to recover the "cost of fuel consumed in the generation of electricity"[17] and the "cost of energy purchased."[18]

Commission rules direct electric utilities to calculate their FCA based on the average of two months of data on fuel-related costs.[19] And while the statute provides for these adjustments to take effect without prior Commission review, they are subject to subsequent Commission review and even refund. The Commission may review each month's filings, and the Commission requires utilities to make annual filings comparing each utility's FCA revenues with the utility's fuel-related costs for the year.[20]

II. The Petitioners

Because IPL, Minnesota Power, OTP and Xcel are now receiving bills related to MISO's Day 2 Market, the petitioners argue that the costs related to this market (offset by the revenues) should be recoverable in the same manner as other energy costs. Specifically, they ask the Commission to authorize recovery of these costs through the fuel clause. To implement this policy, they ask the Commission to approve changes in their fuel clause tariffs to permit automatic recovery of –

> Costs or revenues linked to the utility's load serving obligation, associated with participating 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.

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[15] Minn. Stat. § 216B.16, subd. 7.

[16] Minn. Rules parts 7825.2390 - .2920.

[17] Minn. Rules part 7825.2400, subp. 9.

[18] Minn. Rules part 7825.2400, subp. 7.

[19] Minn. Rules pts. 7825.2600, subp. 2; 7825.2400, subp. 13. But the Commission varied these rules to permit Xcel to calculate its FCA based on forecasts of fuel-related costs for the coming month. *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).

[20] Minn. Rules pt. 7825.2810.

They also ask the Commission to vary Minnesota Rules parts 7825.2390 - 7825.2920 as necessary to permit recovery of amounts that FERC proposes that utilities record to Accounts 447 (Sale for Resale), 456 (Other Electric Revenues), 556 (System Control and Load Dispatching) and 565 (Transmission of Electricity by Others) of the Uniform System of Accounts. Consistent with the Commission's Interim Order, the petitioners propose to record costs together with related revenues, causing all accounts to reflect the net loss or gain from a transaction.

The petitioners pledge that native load customers would continue to receive the benefit of their least-cost source of electric generation. They estimate that granting their request would result in the FCA remaining roughly the same magnitude as it was prior to the emergence of the Day 2 Market. While the TEMT will cause the petitioners to report much greater power purchases, it will also cause them to report greater sales, and the increased costs will largely offset the increased revenues. But in the absence of a variance, OTP argues, the Commission's FCA rules would increase the price of electricity because the rules provide for passing through costs but not revenues.

If the Commission were inclined to deny the petitions, however, the petitioners would ask the Commission to convene a technical conference for purposes of further developing the issues.

III. Positions of the Parties and Commission Action

A. Ripeness

1. Positions of the Parties

The Large Power Interveners urge the Commission to defer action on the current matter, at least with respect to Minnesota Power's petition, until FERC issues its ruling on proposed accounting treatment for RTO costs. They argue that FERC's decision will provide useful insights with which to evaluate the petition. In the meantime, the Large Power Interveners support permitting Minnesota Power to defer recovery of certain MISO-related expenses pending Minnesota Power's next general rate case.

RUD-OAG similarly urges the Commission to defer action on the petitions until FERC establishes its own accounting standards. This recommendation is prompted by RUD-OAG's concern about eroding the Commission's jurisdiction. While awaiting further FERC action, RUD-OAG recommends convening a technical conference to explore jurisdictional issues surrounding electricity generated by a petitioner and used to serve native load customers.

In contrast, the Department urges the Commission to approve the petitions in part. The Department argues that, with appropriate conditions, the Commission can achieve the same consumer protections using the new terminology as using the old. The Department emphasizes that the Commission establishes the accounting treatment for matters within its own jurisdiction, not FERC. Moreover, the Department observes, no one knows when FERC will act or whether its actions will provide much illumination.

Finally, the petitioners ask the Commission to grant their petitions. They dispute the suggestion that approving their requests could cause the Commission to lose the authority to scrutinize the components of retail rates, or to protect ratepayers from bearing inappropriate costs. But if the Commission were inclined to deny the petitions, the petitioners urge the Commission instead to convene a technical conference for purposes of further clarifying the issues involved.

2. Commission Action

As a preliminary matter, the Commission must determine whether the issues raised by the petitioners are ripe for resolution. The Commission has already authorized the petitioners to recover MISO-related costs through the fuel clause on an interim basis. The petitioners and the RUD-OAG advocate different courses of action, but agree that the Commission should convene a technical conference before it renders any permanent decision contrary to their positions. The RUD-OAG advocates deferring any decision until after the FERC has promulgated rules on appropriate RTO accounting. These parties provide the Commission with adequate support to postpone its decision.

The Commission is concerned about the cost of inaction in the current case. The Commission authorized the petitioners to begin recovering their costs on the condition that the utilities would be responsible for refunding any revenues that the Commission subsequently determined to have been collected inappropriately. The petitioners' liability for a potential refund has increased ever since. Put another way, ratepayers are potentially paying too much for electricity, and the debt owed to them grows by the day. Urging prompt Commission action, the Department emphasizes the Commission's duty to ensure that utility rates are just and reasonable.

In the interest of ensuring reasonable rates, the Commission will proceed to scrutinize the petitioners' practices and proposals for using the fuel clause to recover Day 2 Market costs. But in the interest of providing parties with a maximum opportunity to develop their arguments, the Commission will again make its decision on an interim basis. By establishing a one-year duration, the Commission will ensure that all issues receive further consideration with the benefit of additional experience and, presumably, additional FERC guidance.

In the meantime, the Commission will initiate a new investigation and convene a technical conference, but with the goal of placing MISO costs in a broader context. In authorizing the petitioners to transfer control of assets to MISO,[21] the Commission remarked on the lack of quantitative forecasts comparing the consequences of joining MISO to other alternatives. In the three-and-a-half years since that Order, all parties have gained broader experience with various strategies for securing electricity. The Commission finds that now is an appropriate time to start a general inquiry about the optimal methods for securing low-cost, reliable electricity for Minnesota ratepayers.

The Commission will seek input from all knowledgeable people and entities, and will begin by inviting comment on the appropriate scope for this new inquiry. At a minimum, the Commission will design the investigation to address the following alternatives:

- The formation of a transmission-only entity for Minnesota, perhaps modeled on the American Transmission Company, LLC.[22]

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[21] See note 5 *supra*.

[22] 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).

- 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.

By more thoroughly developing all potential alternatives, the Commission hopes to gain greater insight into the possibilities and constraints available; these insights will inform the Commission as it addresses the future of electric service in Minnesota.

B. Defense of State Jurisdiction

1. Positions of the Parties

RUD-OAG asks the Commission to clarify the extent of its jurisdiction. Specifically, RUD-OAG expresses concern that by authorizing utilities to recover TEMT costs, the Commission might tacitly ratify the TEMT's re-characterization of retail electric service.

As noted above, traditionally electric utilities are understood to generate their own electricity, transmit it to their own load centers, and distribute it to their own retail customers. State regulators have the authority to scrutinize a utility's operations and set rates such that ratepayers do not bear any inappropriate costs. Arguably the TEMT may be read to characterize a utility’s transactions as generating electricity to sell into a wholesale market pursuant to a FERC-approved tariff, arranging transmission pursuant to a FERC-approved mechanism, and purchasing the electricity back from that FERC-approved market. RUD-OAG is concerned that this distinction may be more than semantic. State regulators generally lack the authority to second-guess the propriety of FERC-approved rates,[23] and therefore may lack the same authority to protect ratepayers from the consequences of those rates.

The Department, the Large Power Interveners and the petitioners dispute the suggestion that approving the petitions would have any bearing on the Commission's jurisdiction over retail rates. They note that the petitioners' requests -- to recover certain costs from Minnesota ratepayers through Minnesota's fuel clause -- are matters governed by Minnesota statutes and rules.

Moreover, the Department, the Large Power Interveners and the petitioners all propose measures to maintain the distinction between wholesale and retail transactions, although they disagree in some particulars:

Net Accounting. While the petitioners continue to generate electricity and serve their retail customers as usual, the TEMT characterizes virtually all electric generation as a sale into the wholesale market, and virtually all retail service as a purchase from the wholesale market. The fictional nature of these sales and purchases is demonstrated by the fact that they largely offset each other; only the difference between total purchases and total sales reflects a utility's "real" purchases or sales of electricity, as those terms have traditionally been understood.

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[23] *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 106 S.Ct. 2349 (1986) (In establishing intrastate rates, state may not dispute FERC-prescribed interstate power rates).

However, the practice of recording sales proceeds to Account 447 (Sale for Resale) and recording purchases to Account 555 (Purchased Power) potentially promotes the illusion that a utility is serving its native load entirely out of wholesale power purchases. To avoid this problem, the Department, IPL and Xcel recommend recording electricity purchases and sales to the same account. In particular, to the extent that the Commission authorizes a petitioner to use the fuel clause to recover Day 2 costs and revenues incurred to serve native load customers, the Department recommends that the petitioners record in separate subaccounts of Account 555, on an aggregated basis any revenues and costs linked to MISO's Day 2 locational marginal pricing. This could include generation offers to the market and load purchases used to service native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause. This practice would not only demonstrate the retail nature of the transaction, it would help regulators track Day 2 Market costs. No petitioner objected to this proposal.

Hourly Accounting. Hourly accounting provides advantages similar to net accounting. To avoid similarly overstating wholesale sales and purchases as those terms have traditionally been understood, IPL and the Department recommend that petitioners continue the practice of recording these transactions on an hourly basis. No party objected to this proposal.

Accounting for True Wholesale Transactions. Rather than using Account 447 to obscure retail transactions, as discussed above, the Department recommends that the petitioners continue the practice of using 447 to record true sales to other utilities. The Department recommends that petitioners record all the Day 2 costs and revenues relevant to each transaction in a separate sub-account of 447.

OTP objects to this recommendation because it has already begun recording such transactions to Account 555, but IPL and Minnesota Power have already adopted policies similar to the Department's recommendation.

Accounting for Costs Excluded from the Fuel Clause. If the Commission excludes any Day 2 costs and offsetting revenues from the fuel clause, the Department and Minnesota Power agree that petitioners should record those costs and revenues to separate sub-accounts of 555. No party objected to this proposal.

Fuel Accounting. The Department recommends that petitioners continue the pre-Day 2 practice of recording the cost of fuel used for the benefit of native load customers to Accounts 151 (Fuel Stock) and 501 (Fuel). No party objected to this proposal.

Transactional Accounting. The Department recommends that each petitioner allocate an equal share of its Day 2 charges to each Day 2 transaction. Minnesota Power argues in favor of allocating those costs in proportion to the amount of energy in each transaction. Such a policy would allocate charges heavily to a petitioner's retail transactions, however, because the great majority of a petitioner's Day 2 transactions reflects energy that the utility generates and provides to its own native load customers.

Least-cost generation. Beyond accounting issues, the Department and the Large Power Interveners argue that petitioners should provide their retail native load customers with the benefit of their least cost sources of electricity. This proposal would shield customers from higher spot-market prices, as the petitioners did prior to the emergence of the Day 2 Markets. Petitioners indicate that they have always operated in this fashion, and had intended to continue. In this manner, the petitioners seek to provide ratepayers with the same benefits as they received prior to the start of the Day 2 Market.

2. Commission Action

Based on the arguments of the Department, the Large Power Interveners and the petitioners, the Commission is persuaded that it may proceed to authorize recovery of costs through the fuel clause without affecting its jurisdiction.

In creating the Federal Power Commission (now FERC), Congress expressly provided for states to exercise their own jurisdiction:

> (a) Federal regulation ... extend[s] only to those matters which are not subject to regulation by the States.
>
> (b)(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy.... [FERC] shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[24]

This language provides that FERC's jurisdiction supplements, not supersedes, the regulatory power of the states.[25] FERC has acknowledged that Congress did not grant it authority over bundled retail electric service.[26] And an agency may not attempt to achieve indirectly that which Congress precluded directly.[27]

The Commission finds that the parties' recommendations help to clarify the distinction between wholesale and retail transactions, and will facilitate future scrutiny of Day 2 costs. And critically, the Commission requires native load customers to receive the benefits of their utility's least expensive source of electricity. These practices should help reduce confusion about the types of transactions that fall within the Commission's jurisdiction. These recommendations will be approved.

Fundamentally, this Order simply reflects an attempt to match the language of MISO's Day 2 Market bills with the policies of Minnesota's fuel clause. The petitioners do not allege that the Commission is preempted or otherwise precluded from protecting ratepayers. To the contrary,

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[24] 16 U.S.C. § 824.

[25] *Arkansas Power & Light Co. v. Federal Power Com'n*, 156 F.2d 821 (D.C. App.1946), reversed on other grounds 330 U.S. 802, 67 S.Ct. 963, rehearing denied 330 U.S. 856, 67 S.Ct. 1090; *Dunk v. Pennsylvania Public Utility Commission*, 232 A.2d 231 (Pa.Super.1967), affirmed 252 A.2d 589, 434 Pa. 41, certiorari denied 396 U.S. 839, 90 S.Ct. 99.

[26] *Northern States Power Co. v. FERC*, 176 F.3d 1090, 1096 (8th Cir. 1999); FERC Order No. 888, FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996, ¶ 31,036, 31,699, 61 Fed.Reg. 21540 (1996).

[27] *Altamont Gas Transmission Company v. FERC*, 92 F.3d 1239, 1248 (1996).

through various means the petitioners demonstrate their intention to maintain their pre-Day 2 operations on behalf of retail customers to the greatest extent possible. The Commission has always had the authority to disallow inappropriate costs passed through the fuel clause, and nothing in this Order alters that fact. The Commission cedes none of its authority to scrutinize a utility's operations and set rates based on the costs that a prudently-managed utility would incur to provide service.[28]

C. Accounting for and Recovery of Day 2 Market Costs

1. Cost of Energy Used to Serve Native Load Customers

a. Positions of the Parties

Among the costs the petitioners seek to recover through the fuel clause are the net costs of energy. To the extent that this would require the Commission to vary its rules, they ask for a variance.

The Large Power Interveners recommend that the petitioners be authorized to continue using the fuel clause only to recover the cost of energy used to serve native load customers. The Department agrees. According to the Department, the relevant Day 2 costs are reflected in two components of locational marginal pricing: the marginal cost of energy and the marginal line loss. The energy costs consist of the following:

1. Day-Ahead Asset Energy Amount's energy component,
5. Day-Ahead Non-Asset Energy Amount,
13. Real-Time Asset Energy Amount's energy component,
21. Real-Time Net Inadvertent Distribution, and
22. Real-Time Non-Asset Energy Amount.

The line loss costs consist of the following:

1. Day-Ahead Asset Energy Amount's transmission loss component,
3. Day-Ahead Financial Bilateral Transaction Loss Amount,
7. Day-Ahead Loss Rebates on Carve-Out Grandfathered Agreements,
9. Day-Ahead Loss Rebates on Option B Grandfathered Agreements,
13. Real-Time Asset Energy Amount's transmission loss component,
14. Real-Time Distribution of Loss Amount,
15. Real-Time Financial Bilateral Transaction Loss Amount, and
18. Real-Time Loss Rebates on Carve-Out Grandfathered Agreements.

The Department recommends that the Commission approve recovery of these costs, offset by revenues, through the fuel clause. Because Minnesota Rules part 7825.2400, subpart 7, does not provide for offsetting revenues, the Department recommends varying this rule, but only for a period of one year. A one-year variance ensures that this matter will receive additional review when all parties have gained more experience with this the Day 2 Market. In response, petitioners suggested an 18-month period.

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[28] *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of W. Virginia*, 262 U.S. 679, 692-93, 43 S. Ct. 675, 679 (1923).

b. Commission Action

The Commission finds the Department's recommendation consistent with goals of the fuel clause. Minnesota statute authorizes automatic recovery of certain types of large expenses that are prone to fluctuate for reasons beyond the utility's control. The Department's recommendation best identifies those costs that fulfill this statutory purpose.

The Commission is further persuaded of the need to address these matters with the benefit of additional experience. As noted above, the Commission will err on the side of caution and approve the cost recovery until one year after the opportunity for reconsideration of this Order has expired and any petitions for reconsideration have been resolved.

The Commission may vary its rules when 1) enforcing the rule would cause excessive burdens, 2) granting the variance would not harm the public interest and 3) granting the variance would not conflict with any other law.[29] The Commission acknowledges that its current rules provide for passing through fuel-related costs, but make no provision for fuel-related revenues; enforcing these rules as written would likely impose an unjust burden on ratepayers. Similarly, granting the variance would serve the public interest by permitting the costs to be offset by corresponding revenues, resulting in figures that reflect the net cost of the actual underlying transaction. Finally, the Commission is not aware of any legal prohibitions to granting the variance. To the contrary, the Commission has statutory authority to permit a utility to pass through "federally regulated wholesale rates for energy delivered through interstate facilities."[30] The proposed variance will do just that.

For the foregoing reasons, the Commission will vary its rule to allow recovery of legitimate energy-related costs, offset by revenues, arising from the petitioners participating in the Day 2 Markets to serve native load customers.

2. Costs and Revenues Related to Coping with Transmission Congestion

a. Positions of the Parties

Among the costs the petitioners seek to recover through the fuel clause are the net costs of coping with transmission congestion; this would include costs and revenues related to FTRs. The petitioners argue that these costs, like all MISO costs, are incurred as part of the process of providing electric energy to their retail customers, and therefore should be recovered in the same manner as any other fuel clause eligible cost. Automatic cost recovery exposes the petitioners to less financial risk, they argue, and reduces any risk that one generation of ratepayers will end up bearing costs incurred for another generation's benefit.

The Large Power Interveners argue that Minnesota law does not permit recovery of indirect costs of wholesale transactions through the fuel clause, including costs and revenues arising from FTRs. Moreover, these interveners argue that letting a utility keep all the costs and all the benefits of their FTRs would provide the utility with the appropriate incentive to obtain sufficient FTRs from

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[29] Minn. Rules pt. 7829.3200.

[30] Minn. Stat. § 216B.16, subd. 7.

MISO and to use those FTRs carefully. Where a petitioner's net costs increase due to transmission constraints, the petitioner would have the appropriate incentive to build or advocate for new transmission capacity. And this policy would provide regulators with additional time in which to observe how the petitioners will use FTRs in practice.

The Department agrees with the Large Power Interveners that providing automatic cost recovery of congestion-related costs would reduce a utility's incentive to act in the best interests of ratepayers. But while the Department opposes granting immediate cost recovery, it also opposes precluding such recovery in the future. Instead, the Department recommends that each petitioner file an annual report detailing aggregate congestion costs and FTR revenues incurred in the attempt to serve native load customers, and that the Commission take up the issue at that time. The Department recommends that this information be filed as part of a petitioner's annual report on automatic rate adjustments, and suggests that such filings would provide an appropriate opportunity to consider whether and how ratepayers should share in the costs and benefits of these transactions.

b. Commission Action

The Legislature grants the Commission discretion in the design and application of its fuel clause rules. At least for the present, the Commission will decline to vary its rules to permit the recovery of congestion costs.

In these early stages of the development of the Day 2 Market, the Commission finds merit in providing utilities with an appropriate incentive to learn how to manage their systems for optimal results. And in these early stages, it is important that the Commission retain the authority to shield ratepayers from some of the vagaries of the Day 2 process. Both utility incentives and ratepayer protections would be diminished if the petitioners were assured automatic recovery of their transmission congestion costs.

Instead, the Commission will adopt the Department's recommendation and defer questions about the recovery of transmission congestion costs. The Department proposes to review these costs and revenues as part of the annual review of automatic adjustments (AAA). The Department asks that the petitioners report on these net costs and propose a mechanism for sharing potential costs and benefits. The Commission finds the Department's proposal merits further consideration, and trusts the petitioners will cooperate with the Department in refining it. The Commission looks forward to reviewing the Department's complete proposal in the context of the AAA docket, when all parties will have the opportunity to revisit the issue.

3. Costs of Administering the Day 2 Market

a. Positions of the Parties

Among the costs the petitioners seek to recover through the fuel clause are the costs of administering the MISO System. The petitioners again argue that these costs, like all MISO costs, are incurred as part of the process of providing electric energy to their retail customers, and therefore should be recovered in the same manner as any other fuel clause eligible cost. Automatic cost recovery exposes the petitioners to less financial risk, they argue, and reduces any risk that one generation of ratepayers will end up bearing costs incurred for another generation's benefit.

In particular, the petitioners propose using the fuel clause to recover costs for administering FTRs and the Day 2 Markets as recorded to recover the Financial Transmission Rights Administrative Service Cost Recovery Adder (Schedule 16)[31] and the Energy Market Support Administrative Service Cost Recovery Adder (Schedule 17).[32]

They also seek to flow through "uplift charges." The Day-Ahead Revenue Sufficiency Guarantee Distribution Amount is designed to ensure that the owner of a generator that MISO selects to operate the following day will be compensated for making the generator ready for use. "Option B" charges help protect market participants against the possibility that congestion costs will exceed the value of their FTRs. Uncollectible Default Accounts refer to costs incurred by market participants who subsequently don't pay. And the Real-Time Revenue Neutrality Uplift Amount is designed to recover (or disburse) sums that MISO has no other means to recover (or disburse). MISO cannot link these costs to any specific transaction, so MISO allocates them to participants generally in proportion to the number of kilowatt-hours a participant buys or sells.

The Large Power Interveners argue that Minnesota law does not permit recovery of indirect costs of wholesale transactions through the fuel clause, including administrative and "uplift" costs.

The Department also opposes the practice of recovering these costs through the fuel clause, but for policy reasons. The Department argues that these administrative costs are not sufficiently related to the cost of energy to warrant recovery through the fuel clause. Moreover, the Department has concerns that any contrary decision would provide for the petitioners to recover costs through the fuel clause that they are already recovering through base rates. For example, the Department notes that FERC has ordered that “control area costs” be recovered in the same manner as Schedule 17 costs,[33] and questions whether these costs are already reflected in base rates.

Consequently, if a petitioner seeks to have administrative and uplift charges reflected in rates, the Department proposes that the petitioner incorporate them into a rate case. At that time, the Department proposes that each petitioner examine a revenue-sharing or benchmarking system of off-system sales or other significant revenue streams attributable to MISO's Day 2 market that would offset increased costs from participation in MISO's Day 2 market. In this manner, the Department would hope to find additional ways to protect ratepayers from the costs of administering the Day 2 Markets.

b. Commission Action

A general rate case remains the standard process by which a utility may change its rates; a rate case provides an opportunity to compare all of a utility's costs and revenues simultaneously. Automatic adjustments such as the fuel clause remain an exception to this rule. If virtually all Day 2 costs were considered eligible for recovery through the fuel clause, the exception would swallow the rule and the ratemaking process would be undermined.

[31] TEMT pp. 992-1000.

[32] TEMT pp. 1000-09.

[33] Order Approving Contested Settlement, FERC Docket Nos. ER04-691-002, EL04-104-002 (February 18, 2005).

The Commission concludes that the cost of Day 2 administration and "uplift" is too remote to qualify as an energy-related cost warranting recovery through the fuel clause. The Commission acknowledges that Schedule 16 and 17 costs are designed to support the administration of MISO's energy markets, but concludes that these services are only tangentially related to a petitioner's provision of service to its native load customers.

In its Interim Order, the Commission concluded that a utility could only recover MISO's Schedule 10 administrative costs through base rates. The petitioners may seek recovery of these administrative and uplift costs through the rate case process as well.

D. Conditions

1. Positions of the Parties

The Department proposes that the Commission attach the following conditions to any variance it grants:

Designated Network Resources. To help regulators monitor how the Day 2 Market influences the way that the petitioners use their generators, the Department recommends that each petitioner continually disclose which generators the petitioner has designated for use by MISO as a network resource.

Shielding Ratepayers from Market Risk. The Department expresses concern that ratepayers would be asked to bear the cost of a utility’s decision to rely on electricity from the Real-Time Market. To insulate ratepayers from market risk, the Department recommends that the petitioners limit their activity in the Real-Time Market to no more than 5% of total purchases for retail customers. In lieu of this cap, the Department proposes that the Commission scrutinize the petitioners’ Real-Time Market activities – and perhaps order that imprudently-incurred costs be refunded to ratepayers – as part of its annual review of automatic rate adjustments.

The petitioners oppose the use of a cap on the amount of trading they may do in the Real-Time Market. They dispute the suggestion that the Real-Time Market necessarily increases risk. For example, they argue that there is little risk in buying electricity from the Real-Time Market when the market price is less than the utility’s own cost of generation. However, the petitioners do not oppose the Commission reviewing their Real-Time Market activities.

Data Tracking. In addition to the accounting procedures established to maintain the distinction between wholesale and retail transactions, the Department recommends that the petitioners track all MISO charges for both costs and revenues in separate sub-accounts for each charge. At hearing the petitioners did not oppose this proposal.

In addition, the Department recommends that each revenue and expense to Accounts 447 and 555 be recorded individually. At hearing, no petitioner opposed this proposal.

2. Commission Action

The Commission appreciates the Department's efforts to identify relevant data for future analysis, and to protect ratepayers from market risks, especially in the Day 2 Market's early stages. The Commission finds the Department's proposals reasonable and will approve them.

E. Reporting

1. Positions of the Parties

To provide for appropriate oversight, and simply to gain additional information about the practical effects of the Day 2 Market, the Department recommends that the Commission direct the petitioners to provide information on an ongoing basis.

a. Continual Reporting Obligation

First, the Department recommends that each petitioner provide a list of the network resources (such as generators) that it designates for use to serve the MISO system's aggregate load. Petitioners have not expressed opposition to this proposal; some have already complied.

b. Monthly Reporting Obligation

The Department also recommends that the petitioners expand the types of information that they provide with their monthly automatic adjustment (AA) filings, beginning in the second month after the Day 2 Markets begin operations, to include the following:

Fuel Clause Costs/Revenues. Specific Day 2 Market purchases, sales, expense and revenue information for costs and revenues that the Commission permits the petitioner to recover through the fuel clause.

447 and 555 Sub-Accounts. All new MISO costs from Accounts 447 and 555 – to be reported as a line item on Attachment 1 page 1 of the monthly petition, and a summary of those charges.

"Less Loss Rebates Associated with Intersystem Sales." A new AA line item consisting of a credit for the portion of the "Loss Rebates Associated with Purchases" incurred for purchases that were not used to serve retail load, to be reported directly beneath line item 5 ("Less Fuel Cost of Intersystem Sales").

"Less Energy Amounts Associated with Intersystem Sales." A new AA line item consisting of a credit for the portion of the "Energy Amounts Associated with Purchases" incurred for purchases that were not used to serve retail load, to be reported directly beneath "Less Loss Rebates Associated with Intersystem Sales."

"Loss Rebates Associated with Purchases." A new AA line item equaling the sum of the following charge types:

6. Day-Ahead Losses Rebate on Carved-Out Grandfathered Agreements,
9. Day-Ahead Losses Rebate on Option B Grandfathered Agreements,
16. Real-Time Financial Bilateral Transaction Loss Amount, and
18. Real Time Losses Rebate on Carved-Out Grandfathered Agreements.

"Energy Amounts Associated with Purchases." Another new AA line item equaling the sum of the portions of the following charge types incurred for purchases of energy not produced by the petitioner:

1. Day-Ahead Asset Energy Amount (energy and line loss components),
5. Day-Ahead Non-Asset Energy Amount,
13. Real-Time Asset Energy Amount (energy and line loss components),
21. Real-Time Net Inadvertent Distribution, and
22. Real-Time Non-Asset Energy Amount.

Energy Amounts. A statement of --

1. Day-Ahead Asset Energy Amount (separated into energy, line loss, and congestion components),
5. Day-Ahead Non-Asset Energy Amount,
13. Real-Time Asset Energy Amount (separated into energy, line loss, and congestion components), and
22. Real-Time Non-Asset Energy Amount.

Retail Customers/Intersystem Sales. A separate attachment reporting the amounts of each of MISO's thirty-two charge types incurred for the period for which cost and sales values are used in the FCA calculation, stating for each charge type the amount that was incurred to serve retail customers and the amount that was incurred for intersystem sales.

Native Load Forecast. Details and supporting information for load forecast for native load customers, the generation designed to serve native load customers, the actual native load usage, and the difference between the forecasted and actual usage on a daily basis, and summarized monthly.

Shadow Settlements. Information detailing whether the settlement statements produced by MISO conform to the petitioner’s own records as reflected in its “shadow settlement system.”

Also, the Department recommends that the same reports required for Account 555 be required for Account 447.

c. Annual Reporting Obligation

Finally, the Department recommends that each petitioner include the following in its annual reports regarding the automatic adjustment of charges:

Congestion Costs/FTR Revenues. Information on net congestion costs and FTR revenues from serving ratepayers. The report should also include information on the amount of excess FTR revenues recovered from MISO as calculated in the FTR Monthly Allocation Amount and the FTR Yearly Allocation Amount.

Ratepayer/Utility Effects. A summary of the effects of each of the thirty-two MISO Day 2 charge types on ratepayers and the petitioner over the course of the year.

While the petitioners asked the Department to clarify many of its proposals, at hearing none of the petitioners voiced objection.

2. Commission Action

The increased complexity of the Day 2 Market requires increased oversight on the part of regulatory agencies, at least at the beginning. The Department's reporting recommendations should help the Commission obtain the information necessary to ensure fair treatment to both utility and ratepayer. The recommendations will be approved.

F. Refund

In issuing its Interim Order, the Commission authorized the petitioners to begin recovering MISO Day 2 Market costs through the fuel clause provisionally. To the extent that the Commission subsequently determined that the fuel clause was not an appropriate vehicle for recovering any of the costs, the utilities would need to refund the sums to their ratepayers with interest. The Commission has now determined that only energy-related costs, as defined above, should be recovered through the fuel clause. Consequently, petitioners will be required to refund any other amounts collected through the fuel clause. In the interest of administrative convenience, however, the Commission will suspend the refund obligation until after all issues have been resolved on reconsideration. Therefore the refund obligation will begin when the opportunity for reconsideration of this Order has expired and any petitions for reconsideration have been resolved.

ORDER

1. Petitioners may recover costs specific to energy, offset by revenues specific to energy, through the fuel clause.

2. Congestion costs and revenues shall be reviewed in an annual filing.

3. To the extent that a petitioner provides and updates its list of designated resources, the Commission hereby varies Minnesota Rules part 7825.2400, subpart 7, to allow the petitioner to recover through the FCA the legitimate energy-related costs and revenues arising from the participation in MISO's Day 2 energy market for serving native load customers. This variance shall last until one year after the opportunity for reconsideration of this Order has expired and any petitions for reconsideration have been resolved.

4. Each petitioner shall use its lowest cost generation to serve its ratepayers.

5. Each petitioner shall limit its level of activity in the real-time market to 5% of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges (AAA) docket arising pursuant to Minnesota Rules part 7825.2810.

6. Each petitioner shall adopt the following accounting practices:

   A. Recording each transaction to a separate sub-account of Accounts 447 and 555.

   B. Recording to 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 service native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause.

C. Using net accounting for purchases and sales on an hourly basis.

D. Recording MISO Day 2 costs and revenues excluded from the FCA, including MISO Schedule 16 and 17 and uplift charges, in separate sub-accounts of Account 555.

E. Continuing to account for fuel costs related to generation plants serving native load in Accounts 151 and 501, the same way they are accounted for today.

F. Continuing to use Account 447 to reflect the true costs of off-system/wholesale sales, including related MISO costs.

G. Tracking in a separate sub-account each MISO charge and revenue.

H. Allocating all MISO Day 2 charges on a transactional basis.

7. Petitioners shall report as follows:

A. Each petitioner shall provide and update a list of the network resources that it designates for use to serve the MISO system's aggregate load.

B. In each monthly petition for automatic adjustment of charges, beginning in the second month after the Day 2 Markets began operations, each petitioner shall report the following:

1) Specific Day 2 purchases, sales, expense and revenue information for costs and revenues that the Commission permits the petitioner to recover through the fuel clause.

2) The new MISO costs from Accounts 447 and 555 – to be reported as a line item on Attachment 1 page 1 of the monthly petition -- and a summary of all such charges.

3) "Less Loss Rebates Associated with Intersystem Sales," consisting of a credit for the portion of the Loss Rebates Associated with Purchases incurred for purchases that were not used to serve retail load – to be reported directly beneath line the line item adjusting for intersystem sales.

4) "Less Energy Amounts Associated with Intersystem Sales," consisting of a credit for the portion of the Energy Amounts Associated with Purchases incurred for purchases that were not used to serve retail load – to be reported directly beneath "Less Loss Rebates Associated with Intersystem Sales."

5) "Loss Rebates Associated with Purchases," equaling the sum of the Day-Ahead Losses Rebate on Carved-Out Grandfathered Agreements, the Day-Ahead Losses Rebate on Option B Grandfathered Agreements, the Real-Time Financial Bilateral Transaction Loss Amount, and the Real Time Losses Rebate on Carved-Out Grandfathered Agreements.

6) "Energy Amounts Associated with Purchases," equaling the sum of the portions of the following charges incurred for purchases of energy that was not produced by the petitioner: the Energy and Loss Components of the Day-Ahead Asset Energy Amount, the Day-Ahead Non-Asset Energy Amount, the Energy and Loss Components of the Real-Time Asset Energy Amount, Real-Time Net Inadvertent Distribution, and the Real-Time Non-Asset Energy Amount.

7) A statement of --

- Day-Ahead Asset Energy Amount (separated into energy, line loss, and congestion components),
- Day-Ahead Non-Asset Energy Amount,
- Real-Time Asset Energy Amount (separated into energy, line loss, and congestion components), and
- Real-Time Non-Asset Energy Amount.

8) The amounts of each of MISO's thirty-two charge types incurred for the prior two months for which cost and sales values are used in the FCA calculation – to be reported in a separate attachment. For each of the charges, state the amount of the charge incurred for serving retail load and the amount incurred for intersystem sales.

9) Details and supporting information for load forecast for native load customers, the generation designed to serve native load customers, the actual native load usage, and the difference between the forecasted and actual usage on a daily basis, summarized on a monthly basis.

10) Information detailing whether the settlement statements produced by MISO conform to the petitioner's own records as reflected in its "shadow settlement system."

Each petitioner shall make the same reports for Account 447 as is required for Account 555.

C. In annual reports regarding the automatic adjustment of charges, each petitioner shall provide the following:

1) Information on the net cost of congestion costs and financial transmission rights (FTR) revenues from serving ratepayers. The report should also include information on the amount of excess FTR revenues recovered from MISO as calculated in the FTR Monthly Allocation Amount and the FTR Yearly Allocation Amount.

2) A summary of the effects of each of the thirty-two MISO Day 2 charges on ratepayers and/or the petitioner over the course of the year.

8. Each petitioner shall, in its next general electric rate case, examine a revenue-sharing or benchmarking system of off-system sales or other significant revenue streams attributable to MISO's Day 2 market that would offset increased costs from participation in MISO's Day 2 market.

9. The obligation to refund the amounts collected pursuant to the Commission's Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005) shall begin after the opportunity for reconsideration of this Order has expired and any petitions for reconsideration have been resolved.

10. 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 more 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.

11. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)