UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	))	**Docket No. ER04-691-000**
Public Utilities with Grandfathered Agreements in the Midwest ISO Region	))	**Docket No. EL04-104-000**

COMMENTS OF THE ORGANIZATION OF MISO STATES
REGARDING TREATMENT OF GRANDFATHERED AGREEMENTS

I. THE PURPOSE OF THESE COMMENTS

On May 26, 2004, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued its Order Accepting And Suspending Tariff Sheets, Rejecting Tariff Sheets, Setting Timelines And Establishing Procedures For Certain Grandfathered Contracts, 107 FERC ¶ 61,191 ("May 26 Order"). In this Order, the FERC requested input on what it considered to be three critical issues regarding Grandfathered Agreements ("GFAs"):

> 74. The Commission also seeks comments from all affected parties on: (1) whether keeping the GFAs separate from the market would negatively impact reliability; (2) the extent to which GFAs shift costs to third parties; and (3) whether keeping the GFAs separate from the market would result in undue discrimination. These comments should not be repetitive of the protests already filed in this docket, and must be filed directly with the Commission no later than June 25, 2004. We encourage parties with similar interests to combine their responses into a single pleading; however, these responses should not be combined with the GFA information filings described above. Parties will have 14 days to submit reply comments.

These comments are the response of the Organization of MISO States ("OMS") to the Commission request for comments. In our comments, the OMS believes that it is important that the issues raised by the Commission regarding the treatment of GFAs be treated in a unified manner. Thus, while the questions raised by the Commission will be answered, those answers will be in the context of the Midwest ISO's proposed treatment of GFAs, and will thereby raise additional issues that are important to addressing the three questions raised by the FERC.

OMS stands ready to assist both the Commission and the Midwest ISO in putting the finishing touches on the Midwest's market design and moving to the market implementation stage. The following comments should be viewed in the context of the full discussion of the OMS positions submitted in response to the MISO's March 31, 2004 filing in ER04-691.

II. THE MIDWEST ISO'S PROPOSED TREATMENT OF GFAs

The Commission is well aware of issues related to GFAs and has expressed its desire not to abrogate these contracts that pre-date Open Access Transmission Service first granted through FERC Order No. 888.

A. GFAs Are Contractual Arrangements Involving Economic Limits for the Participants.

From an economic perspective, GFAs represent a contract between a buyer and a seller for transmission service, and in many cases are bundled with agreements for capacity and energy. While each contract is to some extent unique, all such contracts represent:

- An upper limit on what the buyer must pay; and
- A lower limit on what the seller will be paid.

This is not to say that these limits are necessarily fixed numbers; for example, the price for a system participation agreement may vary with the seller's cost (e.g., a system participation agreement). What is critical to the economic limits placed into a contract is that variation from these limits for either the buyer or the seller represents a change to the terms and conditions of the contract.

Depending on the specific form of a particular Grandfathered Agreement, the contract can account for any or all of the following economic limits:

1. Generation capacity cost;
2. Generation energy cost;
3. Generation imbalance costs;
4. Generation energy losses;
5. Transmission access cost; and
6. Transmission congestion cost.

It is important to note that in the Midwest ISO Day 2 markets any contract can maintain the limits on generation capacity and energy costs through the application of what is called "Financial Schedules." It is also true that transmission access costs are not subject to change under the Midwest ISO Day 2 markets for Grandfathered Agreements. Moreover, the concern that has been raised in pleadings is the impact that the proposed treatments of GFAs will have on economic limits regarding energy imbalance costs, the cost of energy losses and the cost of transmission congestion.

B. Energy Imbalance Costs

In the Midwest ISO proposed Day 2 markets, schedules and/or bids are submitted into a Day-Ahead energy market. These schedules and bids are settled on a day-ahead basis, and deviations from these settled amounts that occur in the Real-Time market are energy imbalances. Grandfathered Agreements were entered into prior to the existence of a real-time imbalance market for energy. Depending on the form of the contract, either the buyer would schedule its energy or the seller would simply include the load of the buyer as a portion of its native load for which it had the obligation to schedule generation and maintain a predetermined level for net interchange of energy. Scheduled load would be treated in the determination of Net Interchange (net schedules of imports and exports for a control area), and the control area operator would then dispatch generation and use Automatic Generation Control to match the Net Interchange

Schedule. In Order No. 2000, the FERC determined that this particular system of balancing load with generation had to be modified to meet the needs of region-wide energy markets.

The key question is whether or not it is possible to keep unchanged the economic limits on imbalance energy included in GFAs, and if doing so would have any detrimental impact to the reliability of the transmission grid or to other market participants through shifting costs onto others or providing GFAs undue discriminatory use of the transmission system.

First, it is possible to "carve out" GFA transactions from the energy imbalance market. This could be accomplished by allowing settlements of energy to include both the real-time load and real-time generation used to serve that load via GFAs. Thus, whoever is responsible for scheduling the generation and load for a GFA could be required to schedule into the Day-Ahead market, but be allowed to adjust that schedule for real-time actual energy.

Reliability would certainly be impaired if GFAs were not required to submit reasonably accurate schedules into the Day-Ahead markets. Without some form of limits to adjustments, there would be no incentives for GFAs to even submit schedules on a day-ahead basis. For example, revisions to schedules submitted day-ahead could be limited to three percent (3%), and any differences beyond the 3% limit would be subject to the energy imbalance market.

Allowing certain parties to adjust schedules without allowing that same option to all parties is by its very definition discriminatory. However, at the time these contractual rights were entered into, they were not considered to be discriminatory based on the system of energy imbalance that was in effect at that time.   Moreover, the issue is whether or not the different treatment results in *undue* discrimination. One way to measure the impact of allowing GFAs to adjust schedules is to estimate the effect that this would have on other market participants. Any adjustments to schedules will only affect the settlement position of the supplier,[1] however, there could be third party impacts as noted in sections C and D below.

If the buyer is forced to schedule the GFA transaction and pay for energy imbalances that may flow from its schedule, there is possible economic detriment to the buyer. In that same instance, requiring either the supplier to schedule the load instead or allowing the buyer to adjust its schedule to actual loads gives an equivalent result, and absent charges for energy losses or congestion, the supplier should not be harmed. Moreover, it is clear that the energy imbalance market is not a major issue when dealing with GFAs as long as buyers are not forced to schedule their loads and pay energy imbalance charges.

C. Cost of Energy Losses

The Midwest ISO is including marginal losses in its calculation of nodal prices. This is clearly an important market practice that prevents the distortion of bids from suppliers. As a residual calculation, it is possible to separate out the loss component of locational marginal prices ("LMPs") from any generator or set of generators to any load or set of loads. When revenues from LMP payments for losses are added together they will exceed the payments made to generators who actually supply the actual (sometimes called "average") losses. The Midwest

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[1] Since the load and generation are both adjusted to reflect actual levels, the buyer would be paying or credited for the contractual cost for the energy imbalance rather than the nodal price at the load, and the seller's energy imbalance would be adjusted so that it would receive or pay its contract price for the energy imbalance rather than the nodal prices at its generators.

For example, if actual load is 5 MW higher than scheduled load, the scheduled load would be adjusted up by 5 MW and there would be no energy imbalance at the load. In addition, the generation would also be adjusted up by 5 MW and this would change the energy imbalance for the seller. If, prior to the adjustment, the seller has a positive 10 MW imbalance, that imbalance would be reduced to 5 MW. Instead of receiving real-time LMP payments for the additional 5 MW, the buyer would pay the seller the contract price for the additional 5 MW.

If the actual load is 5 MW lower than the scheduled load, the scheduled load would be adjusted down by 5 MW and the scheduled generation would also be scheduled down by 5 MW. If the seller's energy imbalance is –10 MW, the adjustment in the schedule would change this imbalance to –5 MW. Instead of paying real-time LMP payments for the additional –5 MW, the seller would be credited the contract price for reducing its generation to serve the buyer's actual load.

ISO tariff allows this excess revenue from loss payments to be indirectly paid back to load-serving entities that paid for the losses.

Under the Midwest ISO proposed tariff, GFAs taking Option B[2] would be directly refunded the difference between marginal and average losses. This adjustment is financial, not physical and should have no impact on reliability. However, depending on the terms and conditions of their contract, the Midwest ISO proposed treatment of losses could have a detrimental impact on the parties to the GFA. Moreover, if the contract already has a provision of energy losses, it is virtually impossible that such provisions are economically equivalent to paying for average losses based on LMPs.

The true economic cost of energy losses is the average cost of losses as calculated by the Midwe

st ISO. Therefore, to allow substitute loss calculations for each GFA contract will have an economic impact on the pool of dollars available to refund to third-party market participants. Thus, the Commission should find that to allow the loss provisions of the GFA contracts to substitute for the Midwest ISO calculation of losses is unduly discriminatory, and the proposal for direct refund of losses to GFA's under Option B is a just and reasonable method to apply to GFAs that take Option B.

D. Transmission Congestion Costs

[2] Option B provides that the GFA Responsible Entity will not nominate or receive FTRs. The Midwest ISO will charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but – if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, in keeping with section 39.1.4 – the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead schedules that the GFA Responsible Entity clears in the dayahead market. The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then – as before, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA – credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points. May 26 Order, paragraph 21 (footnotes omitted).

Of the three key areas, a transmission congestion cost is the most complex. For example, consider the fact that some GFAs require the buyer to pay any redispatch costs that are incurred by the seller.[3] On the other hand, some GFAs give the buyer full access to the transmission grid irrespective of any redispatch costs that the seller might incur.[4]

1. The Midwest ISO Proposed Treatment of Congestion Costs for GFAs under Option B: A Tradeoff in Impacts to Other Market Participants

Essentially, Option B allows the GFA to be forgiven any congestion costs associated with energy scheduled into the Day-Ahead market. In order to account for this in the allocation of Financial Transmission Rights ("FTRs"), the Midwest ISO proposes to nominate FTRs for the GFAs taking Option B in Tier I of the FTR allocation process.

The revenues received for the Midwest ISO nominated FTRs would be used to pay any congestion costs incurred by the GFA scheduled energy transactions. To the extent that the FTRs are sufficient to cover all congestion costs associated with GFA scheduled energy, there would be no direct impact on other market participants. However, if the FTRs are not sufficient to cover all of the congestion costs for GFA scheduled energy transaction, there would be a revenue shortfall that would then be uplifted to all market participants.

By nominating FTRs in Tier I for GFAs taking Option B, the Midwest ISO has maximized the likelihood that the FTRs will be sufficient to cover all congestion costs associated with GFA scheduled transactions. However, if the Midwest ISO is allowed to nominate in Tier 1 a level greater than 35% of total FTRs eligible for nomination, this proposal has another direct

[3] Being subject to the redispatch costs of the seller would be typical for a system participation agreement, where the buyer is paying the incremental cost of the seller's generation.

[4] Not being subject to the redispatch costs of the seller would be typical for a unit participation agreement, where the buyer is entitled to energy from the unit without any restrictions. Even in this case, if the unit is subject to a transmission line relief, the contract may or may not have specific provisions regarding the buyer's rights to energy at the cost of the unit being curtailed.

impact on third-party market participants. Moreover, allowing the nomination by the Midwest ISO to exceed the established Tier I limit effectively reduces the number of FTRs available in Tier I under the simultaneous feasibility test for other market participants.

Thus, there is a trade-off between, on the one hand, possibly impacting other market participants through an uplift of costs resulting from a shortage of FTRs for GFAs, and on the other hand, impacting third-party market participants through decreasing the availability of FTRs in Tier I. In its initial comments, the OMS supported limiting the Midwest ISO's nomination of FTRs for GFAs to the established tier limits. In essence, this approach is more reasonable in that it spreads the costs to all market participants, and minimizes the impacts on individual third party market participants.

2. Option B Has Both Physical and Financial Impact.

There are two aspects of allowing GFAs to be forgiven congestions costs for energy scheduled in the Day-Ahead market. First, the schedules are physical and would use transmission capability available to the market. Second, the forgiveness of congestion costs is financial and impacts the Midwest ISO's calculation of settlements. The financial impacts have already been discussed in the previous subsection, and have no impact on reliability.

The physical aspects of Option B could have an impact on the reliability of the power system in the case where scheduling the GFA energy would result in the Day-Ahead markets not having a feasible solution. In such cases, the Midwest ISO would be required to cut the GFA schedules in order to arrive at a feasible solution.[5]

[5] GFAs account for nearly half of the market. For congested areas, Option B could produce considerable infeasibility in the day-ahead markets, especially during peak times when energy prices as wells as congestion costs are likely to be high.

3. Option B in the Midwest ISO Proposed Tariff Is Unduly Discriminatory and Should Only Be Made Available to GFAs Not Subject to Redispatch Costs

At the beginning of this section on transmission congestion costs, it was pointed out that some GFAs buyers are subject to redispatch costs, while others are not. If the buyer is responsible for the redispatch costs incurred by the seller, then Option B provides the buyer with benefits it would not otherwise receive under the contract. To allow this to occur with the resulting financial impacts uplifted to other market participants is unduly discriminatory.

For each GFA, the FERC must determine whether or not the buyer is responsible for redispatch costs, and if the buyer is responsible for redispatch costs, then Option B should not be allowed for that contract. Instead, the buyer or seller should go through the FTR nomination process to acquire FTRs along with all other market participants. If there is disagreement between the buyer and seller as to which entity should nominate FTRs, an alternative solution is to have the seller make the nominations and file with the FERC its allocation of any revenue shortages or overages from its FTR portfolio to the buyer. This approach would appear to be consistent with the buyer's existing responsibility for the redispatch costs of the seller.

4. Option B in the Midwest ISO Proposed Tariff is Unduly Discriminatory in that It Provides Potential Pricing Benefits to the GFA When the LMP at the GFA Buyer's Load Is Higher than at the GFA's Seller's Generators

In addition to the benefits related to not having to pay redispatch costs, Option B also provides GFA participants that take this option with an additional opportunity for economic gain. This opportunity is best illustrated with an example. Suppose the GFA allows up to 200 MW to be scheduled from the seller to the buyer and the seller is the scheduling agent. The buyer's load requirements are only for 100 MW, but because of congestion between the seller's generation and the buyer's load, the seller knows that the LMP at the load will be higher than at the generation. The seller schedules 200 MW in the Day-Ahead market and is forgiven any congestion associated with that schedule. In real time, the buyer's load is only 100 MW, not the 200 MW scheduled in the Day-Ahead market. In the Real-Time energy imbalance market, the seller receives the LMP at the load times the 100 MW difference between actual and scheduled load. In effect, the seller is allowed to sell its 100 MW of generation into the market at the higher LMP of the load compared to the lower LMP at the generator.

In effect by receiving this higher price the seller is allowed to recover the real-time congestion cost difference between its generation sources and the GFA load destinations. While this same type of recovery for differences between LMPs at load versus generation is available in the Day-Ahead market to all market participants that hold FTRs,[6] the concern related to Option B is that by over scheduling in the Day-Ahead markets, the actual congestion costs that are forgiven under Option B will be for more energy than is needed to fulfill the GFA. This additional forgiveness of congestion costs will result in a greater likelihood that there will be a shortage in revenues collected from FTRs held by the MISO when compared to congestion costs that are forgiven for GFA schedules. Thus, this additional benefit to GFAs comes at an increase in potential uplift cost to third-party market participants that are required to pay their load ratio share of any shortage between FTRs held by MISO and congestion costs forgiven by MISO. Unless Option B is modified to disallow the option to over schedule with increased benefits to GFAs at a cost to third parties, it is unduly discriminatory.

III. CONCLUSION

The OMS urges the Commission to consider the circumstances mentioned in these comments as it resolves the GFA issues before it. These issues should be resolved in ways that

[6] FTRs pay the difference in LMPs between the load destination and generation sources even when the seller does not generate.

avoid adverse affects on other market participants and on the efficient operation of MISO energy markets.

The Organization of MISO States submits these comments because a majority of the members have agreed to generally support them. The following members generally support these comments, with the exceptions noted herein. Individual OMS members reserve the right to file clarifying comments or minority reports on their own regarding the issues discussed in these comments.

Missouri Public Service Commission
Michigan Public Service Commission
Wisconsin Public Service Commission
Iowa Utilities Board
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Minnesota Public Utilities Commission
North Dakota Public Service Commission

For procedural reasons, these members are not able to express a formal position at this time:

Kentucky Public Service Commission
Nebraska Power Review Board

Members not participating in these comments are:

Montana Public Service Commission
Pennsylvania Public Utility Commission
Ohio Public Utilities Commission
South Dakota Public Utilities Commission
Manitoba Public Utilities Board

The Minnesota Department of Commerce, as an associate member of the OMS, generally supports these comments.

Respectfully Submitted,

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Dated: June 25, 2004

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Notice of Intervention on all parties on the official service list compiled by the Secretary in this proceeding.

Dated at Des Moines, Iowa, this 25th day of June, 2004.

William H. Smith, Jr.
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