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March 30, 2007

The Honorable Philis J. Posey
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

**Re:** ***Midwest Independent System Operator, Inc.*, Docket No. ER07-550-000**
**Motion to Intervene and Protest of Indianapolis Power & Light Co.**

Dear Secretary Posey:

Please find attached the Motion to Intervene and Protest of Indianapolis Power & Light Company in the above-referenced proceeding. Attached to the pleading are the following supporting documents:

| | |
|---|---|
| Attachment A | Affidavit of Barry J. Bentley |
| Attachment B. | Affidavit of Lin Franks |
| Attachment C. | Affidavit of John E. Haselden |
| Attachment D. | Affidavit of Michael L. Holtsclaw |
| Attachment E. | Affidavit of Dr. Ronald R. McNamara |
| Attachment F. | March 22, 2007 Presentation at EEI CEO Meeting |
| Attachment G. | MISO 2004 Annual Report |

Please contact the undersigned with any questions about this pleading.

Very truly yours,

William R. Derasmo

William R. Derasmo

Encl.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER07-550-000** |

# MOTION TO INTERVENE AND PROTEST OF INDIANAPOLIS POWER & LIGHT COMPANY


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Dated: March 30, 2007

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**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
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| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER07-550-000** |

**MOTION TO INTERVENE AND PROTEST OF**
**INDIANAPOLIS POWER & LIGHT COMPANY**

Pursuant to Rules 211, 212, and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.211, 385.212, & 385.214 (2006), and the "Notice of Extension of Time" issued on March 7, 2007, Indianapolis Power & Light Company ("IPL") respectfully submits its Motion to Intervene and Protest in the above-captioned matter. This proceeding involves the Commission's consideration of the Midwest Independent Transmission System Operator, Inc.'s ("Midwest ISO" or "MISO") Ancillary Services Market ("ASM") proposal filed on February 15, 2007.

As explained herein, and in the supporting affidavits of Lin Franks, Barry J. Bentley, John E. Haselden, Michael L. Holtsclaw, and Dr. Ronald R. McNamara, IPL has substantial concerns about the ASM and requests that the Commission reject this particular proposal. While not opposed to an appropriately designed ancillary services market, IPL has no confidence that the purported financial benefits of MISO's proposed ASM will materialize. The project's size, complexity, state of incompleteness, overly ambitious implementation schedule, and failure to consider the requirements of all stakeholder sectors in the ASM design create the likelihood of a market that results in the incurrence of unjust and unreasonable costs. MISO's objective must not be the creation of markets for markets sake but rather to enhance the goal of delivery of reliable service at just and reasonable rates. When entities (like IPL) that are to receive the purported benefits from the ASM in terms of lower prices for customers question the project's cost-effectiveness, the Commission should subject the proposal to a strict scrutiny, especially a proposal that mandates participation (*i.e.*, that extends the current must-offer obligation for Energy to Operating Reserves products and does not allow self-supply). Current initiatives such as the Contingency Reserve Sharing Agreement and Adequate Ramp Capability ("ARC") Procedure[1] may capture many of the benefits of the ASM at substantially less cost. IPL has devoted significant resources to the development of the MISO markets, including the ASM initiative. Unfortunately, the ASM filing was made not as a result of close collaboration with stakeholders, but rather despite their legitimate and significant concerns.

As explained herein, IPL asks that, rather than accept MISO's submission under Section 205 of the Federal Power Act, the Commission reject this filing without prejudice, consider the proposal as a conceptual filing, and require the MISO: (1) to retain an independent third-party consultant to do a more complete analysis of the incremental benefits of the ASM proposal that incorporates realistic projections of implementation costs and includes stakeholders in the development, design and oversight of the project; (2) to institute a process for the development of a revised proposal that better meets the criteria for success identified by stakeholders, and (3) to address the concerns of all market participants, including low cost vertically integrated utilities like IPL that need sufficient information and time to coordinate cost-recovery, and the ability to exercise a self supply option, without additional cost exposure. Further, the Commission should permit oral argument on the question of a move from Day 2 Market operations to what in essence will be "Day 3" market operations, given the enormous costs and risks involved.

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[1] On March 19, MISO filed to implement the ARC on March 20, 2007. Region-wide contingency reserve sharing commenced on January 1, 2007.

## I. EXECUTIVE SUMMARY

The Commission should reject this proposal, without prejudice to allow MISO and the stakeholders to develop a more appropriate ASM design. IPL recognizes the significant effort from MISO staff and stakeholders that has gone into preparing the ASM filing. But the sheer size of the submission and a generalized desire to expand the services offered under the MISO tariff to include an ASM is not a substitute for the Commission's responsibility to ensure that the rates customers pay for ancillary service under the jurisdictional tariff remain just and reasonable.[2] The Commission's duty is to protect consumers.[3]

There is good reason for the Commission to take time to reconsider options regarding an appropriate ASM proposal, give conceptual guidance in several specific areas, and let MISO gain additional experience with the Day 2 Market, the Reserve Sharing Agreement, and the new ARC procedures:

- First, **projected ASM costs may be substantially understated.** MISO originally assessed the benefits of its Day 2 Market at $713 million in the 2004 Annual Report with a projected implementation cost of $160 million. As indicated in the ICF report, MISO has spent approximately $246.7 million to date to implement the Day 2 Market and realized benefits of only $70 million. Thus, it is understandable IPL questions the estimated implementation costs of $65 million with projected benefits of $213 million. Equally as important, before proceeding with expanded markets, further analysis must be done as to why the existing Energy market is not meeting prior expectations.

- Second, **projected ASM benefits are substantially overstated.** The projected benefits of the Day 2 Market in the ICF Study are vastly overstated. The projected benefits in the ICF study focused on the "benefits" to society of centralized dispatch. However, these purported benefits are overstated in that

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2 *See Federal Power Commission v. Hope Natural Gas Co.*, 320 US 591, 603 (1944).

3 Utility customers are a "prime constituency" of the Commission. *See Maryland People's Counsel v. FERC*, 761 F.2d 780, 781 (D.C. Cir. 1985) (citing *Hope* at 620). It is fundamental that the Commission's charge is to protect consumers as well as maintaining the financial integrity of public utilities. *See Bluefield Water Works & Improvement v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (balancing of investor and consumer interests means ensuring that the rates are reasonably expected to maintain the financial integrity of the public utility and attract necessary capital and still provide appropriate protection for the public interest and consumers).

they are gross, rather than net benefits to consumers. Administrative costs are not considered; losses are assessed on average losses rather than the significantly higher marginal losses, and other costs born by market participants are not included. In addition, the true benefits of simultaneous co-optimization may be significantly less in the Midwest than in other regions due to the short 10-minute time frame for optimization and the other factors discussed by Dr. McNamara – that the Midwest has an extraordinarily high amount of baseload generation capacity and the physical transmission system does not have the degree of interconnection that is present in other markets.[4]

- Third, **projected ASM benefits are not properly distributed**. Moreover, there is no assurance that the purported benefits of the new market design will be aligned with particular entities commensurate with their burdens. To the contrary, the limited benefits may be concentrated with certain parties while others continue to subsidize those parties through socialized costs.

Despite the volume of its submission, MISO's proposal is not sufficiently developed for acceptance and implementation. MISO's filing represents an overly broad and potentially unnecessarily complex market design, when a much more effective and efficient solution would be to implement comparatively simple changes to the existing energy market. The effective deployment of limited human resources is an important consideration for the timing of effective new policy initiatives. The Commission should be mindful of the significant number of issues and challenges already on the plates of the MISO and its Market Participants as they work to improve the Day 2 Market. As explained by Dr. McNamara in his affidavit,

> There is little argument that better coordination of energy and ancillary services will yield theoretical benefits, but actual results suggest that it is prudent to apply a potentially steep discount to theoretical estimates of benefits, especially in the early years. An important question remains unanswered in the Midwest, why hasn't the implementation of centralized dispatch resulted in actual savings that are close to those predicted by the US Department of Energy, ICF Consulting and even the Midwest ISO itself? Until that question is resolved it is premature to consider adding significant complexity to the existing dispatch process and existing markets. With respect to the specific market design proposal of the Midwest ISO, it is not obvious that the theoretical benefits will translate into actual benefits to market participants.[5]

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4 *Attachment E, Affidavit of Dr. McNamara at* ¶ 19.

5 *Id* at ¶ 5.

Most importantly, MISO has just implemented new initiatives such as the Contingency Reserve Sharing Agreement and the ARC procedure that may capture many of the potential benefits of the proposed ASM at virtually no additional cost. As explained in the affidavit of IPL Vice-President Barry J. Bentley, these initiatives will enable the MISO to more efficiently and effectively utilize already-available reserves. MISO has projected potential annual benefits from these two programs of approximately $188 million.

Accordingly, IPL seeks a brief stay to reorganize and refocus the ASM effort. The Commission should: (1) reject the MISO's ASM proposal in its current format; (2) require MISO to retain an independent third-party to do a true cost benefit analysis of the Day 2 Market from the perspective of the consumers, and that includes the measured benefits of the Contingency Reserves Sharing Agreement and ARC procedures; (3) provide conceptual guidance on a number of the issues raised by MISO's proposal; and (4) establish a process and reasonable timetable for further development of a more appropriate ASM design.

The Commission should understand that delaying implementation will not result in lost opportunity for customers. First, as explained in the affidavit of Dr. McNamara, MISO's prior estimates of potential market benefits have proven to be overly optimistic.[6] There is no foundation to believe that the new design will produce the savings projected by ICF. Second, MISO just recently, on March 20th, implemented the ARC procedure and accordingly has no study of the benefits of this new practice. Third, experience shows that prudent planning is much more cost effective versus hastily designed markets and systems which subsequently must be significantly modified. Fourth, Market Participants, consumers, and regulators suffer harm and lose confidence in markets that have significant problems and excessive costs. For example, care

[6] *Id* at ¶ 19.

must be taken to ensure that the resulting scarcity pricing is legitimate and not the result of the exercise of market power.

In addition, the Commission must ensure that any MISO ASM considers the specific needs and concerns of various market segments – including, but not limited to, the needs of low-cost vertically-integrated utilities like IPL, for the Commission's duty is to strike "a fair balance between the financial interests of the regulated company and the relevant public interests both existing and foreseeable."[7] This includes recognizing aspects of state oversight regarding sufficient reserves, demand-side management ("DSM") program implementation and state ratemaking practice coordination.

MISO fails to consider any implication of state ratemaking in its filing. Virtual trapped costs will be created by MISO's proposal if there are no efficient means to match the ultimate beneficiaries of ASM with the costs to achieve those benefits. Equity requires a matching of costs and benefits, which is problematic if the only available method of matching is through costly and time consuming retail rate cases. This problem is exacerbated when the costs far exceed the benefits.

Given the volume of the submission, IPL has done its best to identify particular issues of concern. IPL asks that the Commission provide conceptual guidance in the following areas:

- **The optimization process** –IPL is concerned that the MISO may not be taking a sufficiently long look-ahead as part of the optimization. This may result in an inefficient dispatch and excessive uplift costs.
- **The process for establishing or changing Reserve Zones** – Absent greater stability in the definition of Reserve Zones, vertically-integrated

[7] *Farmers Union Central Exchange v. FERC*, 734 F. 2d. 1486, 1502 (D.C. Cir. 1984) quoting *Permian Basin Area Rate Cases*, 390 U.S. 747, 792 (1968).

utilities such as IPL cannot properly plan their ancillary service procurement to self supply, hedge, and reduce exposure to uplift costs.

- **The self-supply option** – If a LSE self-supplies 100% of its ancillary service responsibility, it should not bear the financial risk inherent in the difference of Locational Marginal Prices ("LMP") of vertically integrated generation serving retail demand. It is not sufficient for MISO to pay for self-supplied ancillary services at an LMP and charge for the amount consumed on a Market Load Ratio Share. There is an inherent difference between the payment and the charge that cannot be adequately hedged in this nascent market, if it can be hedged at all. The ability to self-supply instead of self scheduling is critical to managing exposure either of the company or its customers.
- **Scarcity pricing** – The proposed demand curves based on a value of lost load of $3,500/MWh will result in unjust and unreasonable prices. Other RTOs, including the California ISO which does not operate a capacity market, utilize scarcity pricing capped at $1,000/MWh. There is no reason that consumers in the MISO footprint should be exposed to excessive scarcity costs, particularly at the outset of an untried market design. The inability, or limited ability to hedge, and the resulting excessive clearing prices present the potential for serious financial harm.
- **State rate impacts and timing** – According to MISO's own witness, the ASM State Ratemaking Study Group (the group responsible for gathering and assessing information on how the costs of Operating Reserves are

recovered through rates and for analyzing the potential revenue impact on the proposed ASM, clearing prices and charge types) "*is in its formative stages*."[8] It is unjust and unreasonable to proceed with implementation of ASM without a full understanding of potential rate impacts to utilities and their customers. The Commission would be abandoning its duty to balance the needs of the regulated entity and its customers and would create a disincentive for RTO participation.

- **The must offer obligation intrudes into areas of state authority over reserves** - IPL has the responsibility to maintain its reserve obligation for its Balancing Authority Area until such time as the Indiana authorities may approve any changes to the existing Balancing Authority Area configuration and responsibilities. IPL's responsibility is inconsistent with a must offer obligation.
- **Cost-causation principles** – The principle of cost causation has been abandoned if all entities must bear a Market Load Ratio Share for contingencies, even if they have self-scheduled or self supplied. Even if a generator with a contingency buys back from the market, that contingency has elevated clearing pricing for at least a portion of the footprint and could have been responsible for clearing prices approaching scarcity, thus elevating the socialized costs of that contingency. MISO's proposed ASM must be rejected for its unjust and unreasonable cost allocation

8 *Id.* (Emphasis added.)

methodology. The cost causer should be held accountable for all of the costs of the contingency.

- **The Business Practices Manual ("BPM") Process** – The Commission should establish a process for stakeholder review of the relevant business practice manuals, prior to implementation of ASM. In addition, the Commission should formalize a process in the Transmission and Energy Market Tariff ("TEMT") which MISO may revise its manuals. This process must be developed together with and approved by the stakeholders and should include a timeline for provision of the BPMs to Market Participants that provides sufficient time prior to its effective date for stakeholders to assess the draft manual's impacts. The process should also include an appropriate change management process.
- **Uninstructed Deviation Penalties** – The Commission should reject the proposal to narrow the tolerance band from 10 percent to 4 percent and apply it on a five minute interval. MISO's proposal fails to take into consideration the different operating characteristics of various types of units.
- **DSM** – As explained in the Affidavit of Mr. Haselden, MISO's Demand Response proposal fails to provide the proper pricing incentives for DSM participation and fails to recognize the need to coordinate DSM participation with existing programs under State jurisdiction.
- **Emergency pricing, price correction and reversal plan** – The Commission should provide guidance on a proper plan to revert to the

previous stable Day 2 Market in the event the ASM does not function properly and on price correction authority for prices that result from unanticipated design flaws.[9]

- **Early Implementation** - It is improper for MISO to presume Commission acceptance of its submission, and MISO should be ordered to cease requiring that Market Participants execute any agreements predicated on the ASM.
- **Self-Supply** - Any ASM proposal should permit self-supply. The current ASM proposal does not. This creates unreasonable risks for customers. In providing guidance the Commission should clarify that self-supply is a requirement for ASM.

Additionally, the Commission must assure that any MISO ASM has been tested and demonstrated to produce reasonable prices during a variety of market conditions prior to implementation. MISO should be required to work with Market Participants to develop readiness criteria that would need to be met prior to the implementation of any ASM, and MISO should certify to the Commission that its staff, systems, and Market Participants are ready to implement the new market. MISO should also be required to regularly evaluate the functioning and value of the ASM after implementation.

IPL reiterates its support of markets. As described in the affidavit of Mr. Bentley, IPL has supported the Day 2 Market as a means of improving grid reliability and the transparency and liquidity of the energy market, which brings about an even playing field for all utilities. Based upon the ICF study results, our concern is that the reality of MISO market operation has

[9] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 at P 36-40 (Aug. 6, 2004) (describing six protective measures associated with the Day 2 Market startup).

not met expectations and that MISO capital and operating costs have been disproportionate to any savings from improved efficiencies. Also of importance, market design issues, such as the imposition of MISO's marginal loss methodology, have imposed significant unanticipated costs to customers. Prudence dictates proceeding in a thoughtful manner and repairing what exists before embarking on a project of tremendous scope, complexity and additional cost.

## II. ORAL ARGUMENT

In the event the Commission is inclined to permit this ASM proposal to move forward, the Commission should permit oral argument on the move from Day 2 to Day 3. There is sufficient evidence of additional, unconsidered costs and risks that the Commission must take this step to ensure that any authorization is based on valid assumptions and data.

## III. INTRODUCTION

### A. Description of IPL

IPL is a vertically-integrated public utility that owns and operates generating facilities with a capacity of approximately 3,400 MW and transmission and distribution facilities required to provide retail electric service to approximately 465,000 customers in and around Indianapolis, Indiana. IPL summer peak demand is 3,118 MW (reached in 2005) and its winter peak is 2,805 MW (reached this past winter). IPL has approximately 3,400 MW of generating capacity of which 2,668 MW is coal-fired. IPL's transmission system, consists primarily of a 345 kV loop around Indianapolis which has adequate capacity to accommodate load growth. IPL is a MISO transmission owner and a party to the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc.

### B. IPL Has Made a Significant Commitment To Participate in the Development of the ASM

As explained in the affidavit of Ms. Franks,[10] IPL has made a substantial commitment to the development of an ancillary service market within MISO. Indeed, Ms. Franks served as Chairman of the Ancillary Service Task Force ("ASTF") and currently serves as Chairman of the ASM State Ratemaking Study Group.

Prior to November 2004, IPL's participation in the MISO stakeholder process was limited to technical and transmission related issues. Beginning in November 2004, IPL has dramatically increased its resource allocation for the MISO stakeholder process, including the development and implementation of the Day 2 Market and MISO's proposal for recovering the costs of transmission expansion. With the implementation of the Ancillary Services Task Force and the initial discussions of the ASM ("Day 3") market, IPL once again increased its resource allocation for the MISO stakeholder process. Currently, IPL has 19 subject matter experts assigned to engage in MISO stakeholder processes related to their specific areas of expertise.

### C. MISO Failed To Conduct an Appropriate Stakeholder Process Prior To the Submission of the ASM

Previously, the Commission has praised MISO for conducting effective stakeholder processes, leading to new initiatives.[11] In its filing letter and in the testimony of Michael Robinson, MISO attempts to describe the stakeholder process utilized for preparation of the

[10] *See* Attachment B, Affidavit of Ms. Franks at ¶¶ 9-20.

[11] *See Midwest Independent System Operator*, 114 FERC ¶ 61,106 (February 3, 2006) at P 15 ("We commend the Midwest ISO, its stakeholders, and the OMS for their significant efforts to develop the cost allocation policy using an open and collaborative stakeholder process that allowed for extensive participation) and P 24 ("We find the process adopted by the Midwest ISO, as described in the October 7 Filing, was an open, transparent, and collaborative stakeholder process and commend the Midwest ISO, its stakeholders and the OMS for their significant efforts to use a process that allowed for extensive participation in the development of the cost allocation policy.").

ASM. Unfortunately, rather than the culmination of a successful iterative process, the ASM represents MISO's determination to proceed in spite of strong reservations expressed by numerous market participants. MISO's testimony and filing letter fail to identify the concerns raised by all stakeholders sectors and to demonstrate how the submission has been modified to address these issues. Changes were made prior to filing that addressed the primary concerns of a few MISO Market Participants, but the concerns of the other, like IPL and end use customer sectors were not addressed. IPL recognizes the difficulty, if not impossibility, of achieving unanimity across the diverse range of entities participating in MISO. Nevertheless, it is incumbent on MISO to remember the core focus of maintaining reliable grid operations at just and reasonable rates. Changes to markets should only occur in ways that facilitate these objectives and must be made only after taking into consideration the specific concerns for the entities and ratepayers that will be most affected by the proposals.

As explained in the attached affidavit of Ms. Franks, the initial effort to develop ancillary services markets for the MISO footprint was set in motion by the stakeholders themselves and not by MISO executives. In February 2005 the MISO Market Subcommittee formed the ASTF with Ms. Franks of IPL as Chairman. The ASTF reviewed the ancillary service markets of other regional transmission providers and developed a work plan for the ancillary service project. Most importantly, the ASTF developed "Success Criteria" that would serve as the benchmark for the ASM design. As provided to MISO on September 22, 2005, and again with the formation of the ASM Project, the success criteria consisted of the following:

1. Transparent Prices
2. Multiple Sellers and Buyers
3. Voluntary sellers -- both generation and demand response
4. A positive benefit/cost analysis
5. Minimize seams issues
6. Equitable process for buyers and sellers

7. Consistent and clear business rules for regulation and spin
8. Availability of self-supply (not the same as self scheduling)
9. Measured reliability improvements
10. Ancillary Service charges would be according to appropriate cost causation principles
11. Does not promote market power abuse
12. Market systems can accommodate more than one zone if necessary
13. Sellers can offer Ancillary Services to other RTOs and external entities
14. Market administrator is responsible for appropriate reliability standards (through NERC functional model)
15. Consistent with Energy Policy Act
16. Transitional approach may be required to move from existing Ancillary Service procurement environment to desired end-state
17. Transparent and auditable billing and settlement

As explained in this pleading, MISO's failure to respect these criteria has led it to submit a proposal that will result in unjust and unreasonable rates. At the Advisory Committee on January 17, 2007 the vote on ASM was 19.5 *against* with 3.5 abstentions. There were *no* votes in favor of the proposal.

In fact, IPL suggests that while some of the criteria listed are addressed in the design, most critical criteria are not. Those criteria are: That the markets be voluntary (no. 3); that the benefits to consumers outweigh the costs (4); that the business rules are consistent and clear (7); that one be permitted to self-supply or opt-out of the ancillary services markets (8); that costs be allocated according to cost causation principals (10); that sellers are free to offer their ancillary services products into other RTOs; and the penultimate criteria – an appropriate transition plan to accommodate the need and conditions of state regulations. Most notably MISO has rejected the important option that participation in the ASM be *voluntary* and that stakeholders be given the opportunity to self-supply, without cost exposure to differences in prices between the amounts paid to ancillary service market suppliers and those paid by loads.

IPL submitted its February 14, 2007 letter to Chairman Kelliher because it believes that MISO dismissed legitimate concerns of many stakeholders in the MISO ASM filing. In addition to IPL, the letter was signed by Southern Illinois Power Cooperative and Hoosier Energy, all of whom are registered with MISO as vertically integrated transmission owners; WPS Resources who is registered in the MUNI/COOP/TDU sector; Coalition of Midwest Transmission Customers and Midwest Industrial Customers representing the End User Sector; and the Electricity Consumers Resource Council representing large industrial customers. The February 14 letter signed by this diverse group noted that as proposed the ASM was "a recipe for failure."

The Commission must take action to restore the faith of Market Participants that their voices will be heard in stakeholder processes. The MISO stakeholder process requires a significant amount of IPL resources to support the MISO processes. IPL makes the human resource commitment to work collaboratively with MISO staff to enhance the existing Day 2 Market and to protect the rights of its electric consumers. However, the stakeholder process risks becoming nothing more than a sham if MISO charts a course of pre-determined action with little or no consideration of the impact to stakeholders and/or their constituents.

## IV. MOTION TO INTERVENE

IPL moves to intervene in the above-referenced proceeding. IPL has been and continues to be an active participant in numerous Commission proceedings regarding the TEMT. As a Midwest ISO transmission owner, IPL has a direct interest in the above-referenced proceeding that cannot be adequately represented by any other party. Accordingly, IPL asks that the Commission grant this motion and allow IPL to participate fully as a party to the above-referenced proceeding.

## V. SERVICE OF DOCUMENTS

Pursuant to Rule 2010, 18 C.F.R. § 385.2010, IPL hereby designates the following people for service of documents in this proceeding:

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## VI. PROTEST

### A. The Commission Should Not Accept the Filing But Treat It as a Conceptual Proposal and Give the MISO and Market Participant's Guidance and Time To Complete an ASM Design

The Commission should not accept this filing. The Commission should reject this filing without prejudice and provide guidance regarding an appropriate design for ASM under the rubric of the existing "Day 2" market design within MISO. Such treatment would be consistent with past practice where MISO[12] or other regional market operators have sought to revamp the overall structure of the wholesale market.[13] Treating the filing as a "conceptual proposal" is a reasonable step that recognizes the significant effort that has gone into the ASM design to-date but also prudently considers that much more needs to be done to ensure that it respects the needs of various market segments and contains appropriate consumer protections.

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[12] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,145 (2003) (accepting motion to withdraw filing and providing guidance on key elements of the Day 2 market design).

[13] *See, e.g.*, *California Indep. Sys. Operator, Inc.*, 116 FERC ¶ 61,274 at P 3 (2006) (discussing the issuance "of over 30 orders providing guidance" to the California ISO and stakeholders).

### 1. This Proposal Was Overwhelmingly Rejected By Stakeholders.

The ASM proposal was overwhelmingly rejected by a January 2007 Advisory Committee stakeholder vote. To emphasize, *not a single vote in favor of the ASM was cast.*[14] Ignoring the majority of its customers, MISO nevertheless forged ahead with the ASM filing. Subsequent to this vote, MISO identified three issues important to a small subset of Market Participants and instituted changes to accommodate that group. In the past, MISO withdrew market redesign filings that were not sufficiently developed and did not have sufficient stakeholder support.[15] Regardless of whether or not MISO voluntarily withdraws the filing in the present case, the Commission should send an important signal to MISO and reject the filing without prejudice and merely provide conceptual guidance.

The ASM is not a simple adjunct to the Day 2 Energy Markets, but instead, represents a "lock, stock and barrel" change to the competitive energy markets, *in addition to* the start-up of an Operating Reserves Markets. In this sense, MISO is now asking the Commission to scrap the Day 2 Market platform and authorize the start-up of what is in effect a "Day 3" market. The chart below demonstrates the differences in MISO's Day 2 versus Day 3 market design.

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[14] The vote was 19.5 opposed, 0 in favor, with 3.5 abstentions. While a group of independent power producers and marketers submitted a letter on March 2, 2007, attempting to cast doubt on the importance of the stakeholder vote, IPL notes that their letter fails to specify how the proposal is different in any significant way from the proposal considered in January or how the proposal addresses the concerns of customers (as opposed to independent power producers and marketers, the group behind the March 2, 2007 letter). Moreover, it is telling that MISO did not take any more stakeholder votes before submitting the ASM proposal.

[15] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,145 (2003) (providing guidance with respect to Day 2 proposal that faced significant stakeholder opposition).

## MISO Day 1→ Day 2→Day 3

| RTO FUNCTION | Day 1 | Day 2 | Day 3 |
|---|---|---|---|
| Reliability coordination | √ | √ | √ |
| OATT administration | √ | √ | √ |
| De-pancaked transmission rates | √ | √ | √ |
| Regional planning | √ | √ | √ |
| Security constrained economic dispatch energy only (regional) | | √ | |
| Centralized energy-only markets (day ahead energy market, real time balancing) | | √ | |
| Locational marginal pricing – energy | | √ | √ |
| Simultaneous Co-Optimization of energy, contingency reserves, and regulation day ahead and real time | | | √ |
| Scarcity Pricing, Value of Lost Load | | | √ |
| Must Offer for Contingency Reserves and Regulation | | | √ |
| Balancing Authority Functional Consolidation – MISO becomes a BA | | | √ |
| Post Transition Transmission Rate Administration | | | √ |
| Locational marginal pricing – operating reserves | | | √ |

MISO's proposal is entirely unnecessary, costly, and creates significant new risks for stakeholders, MISO, and the Commission. While MISO's move from Day 1 to Day 2 was not without controversy in and of itself, performance appears to be improving. Nevertheless, Market Participants and MISO are still working on specific fixes to Day 2 Market shortcomings. Now, MISO inexplicably proposes to "throw the baby out with the bath water" by discarding the Day 2 design. Moreover, as Dr. McNamara states, implementation of the ASM may cause unanticipated problems with the Day 2 Market:

> The greatest risk to the overall market from implementing the ASM project is that the added complexity contributes to a failure of the market component (as compared to the dispatch component) of the Day 2 energy markets as a result of (1) greater un-hedgeable risk, i.e. uplift, (2) reduced liquidity as participants hedge their exposure to the "ASM enhanced" Day 2 markets with greater reliance on physical rather than financial positions, and (3) higher and more volatile prices. IPL as well as other market participants benefit from, and wish to participate in, well functioning electricity markets that deliver actual benefits.
>
> Given the potential caveats that arise from how the energy and ancillary service markets will work in reality, the projected theoretical net benefits of $88 to $183 million dollars is potentially well within the margin of error. There is need in this

> discussion to look at the issues from the perspective of a Market Participant and focus on questions such as what is the likely effect of this design on the forward curve, will this reduce the potential number of counterparties, what aspects can or cannot be hedged, how understandable are the dispatch outcomes, etc? In other words, while it is convenient to talk about "the" market it is easy to forget that there are actually many interrelated markets that rely and respond to information. Conceptually the aggregate of these markets is "the" market and it is much broader than dispatch and the associated Midwest ISO administered Day Ahead and Real Time markets. From an overall Market perspective, the Midwest ISO administered markets, while an important piece of the overall puzzle, should never be the "primary" markets rather they should be balancing markets where "overs and unders" from bilateral contracts are filled. Just as the interdependency between energy and ancillary services should be recognized, so too should the relationships between all the markets.[16]

The existing problems with the Day 2 Market are likely susceptible to specific, targeted solutions that are far less costly and time-consuming than the market re-design approach that MISO has taken with its ASM filing. For instance, as discussed in greater detail in the Affidavit of Mr. Bentley, implementation of MISO's Contingency Reserves Agreement and ARC procedures may go a long way in allowing MISO to operate the system in a more efficient manner and provide value to customers.[17] In MISO's April 3, 2006 information filing on Balancing Authority consolidation, MISO represented that $188 million in annual benefits could be realized by implementation of the Contingency Reserve Agreement ($118 million) and the

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[16] Attachment E, Affidavit of Dr. McNamara at ¶ 21.

[17] *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,009 at P 32 (2007) (finding that "ARC should reduce costs by helping to avoid the commitment cost of peakers, use of regulation up, and the cost of frequency fluctuations"); MISO "went live" with the ARC procedures as of March 20, 2007. Docket No. ER06-1099-000 & ER06-1099-001, Letter from Gregory A. Troxell to Secretary Salas (Mar. 19, 2007). As explained by Mr. Bentley in his affidavit, market participants carry additional spinning and supplemental generation for regulation and contingency reserve requirements to meet NERC/ERO reliability requirements. MISO maintains similar generating reserves to help maintain reliability since they have limited access to market participants' collective reserve resources. The newly implemented ARC procedures provide MISO with the ability to access 50% of market participants' collective contingency generating resources for short term periods to avoid starting expensive peaking units and/or to carry additional high cost spinning resources to maintain their own reliability requirements; all of this while possibly paying make whole payments to those generator owners when the locational marginal price does not cover the offer price of those high priced resources. Fundamentally, it does not make sense for both MISO and market participants to carry redundant resources for reliability. However, an expensive and complex ASM design is not necessary to solve this fundamental, yet relatively simple problem. In fact, the new implemented ARC procedures should provide substantial Day 2 savings by sharing contingency reserves to maintain NERC/ERO reliability requirements and to provide greater market efficiency by eliminating some of the duplication in cost.

ARC procedure ($70 million).[18] As Mr. Bentley explains, these two initiatives are being implemented at virtually no additional cost.[19] If they do achieve the $188 million in benefits no additional significant market redesign may be warranted, but, at a minimum, operational experience needs to be gained under these programs to better assess the potential impact of the far more complex and costly ASM.

As described by Dr. McNamara:

> Simultaneous co-optimization is certainly a theoretically elegant solution. Moreover, FERC has approved, and other RTOs have implemented, the administered demand curve approach. Obviously, any move toward improved price signals and greater demand side participation is a positive step. But the real question – the one that deserves the most attention from regulators and market participants alike - is whether this particular market design and implementation program will result in actual, rather than theoretical benefits. In other words, is this "market" design likely to deliver benefits in the real world? Often, but not always, theoretical elegance comes at a price. And the price in this case is complexity, which is not necessarily a bad thing, but as a general rule "markets" prefer simplicity to complexity. More correctly, markets produce better outcomes the simpler, more transparent, and less discretionary the rules are. While simplicity is preferred to complexity, no market should be more or less "simple" than it needs to be. There is no doubt that the proposed Midwest ISO ASM design is complex. Indeed, nowhere in the filing is the market described as "simple". Nor does it appear that this was a consideration, let alone a criterion, in the design process.[20]

Moreover, while the Commission has issued a series of orders regarding improvements to the Day 2 Market design, MISO is under no specific mandate to implement this particular ASM market. Indeed, MISO has apparently authorized the delivery of ASM computer code prior to

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18 Attachment A, Affidavit of Mr. Bentley at ¶ 18.

19 *Id.*

20 Attachment E, Affidavit of Dr. McNamara at ¶ 14.

Commission action on the filing.[21] For whatever reason, MISO has approached ASM implementation with uncommon zeal in the face of little stakeholder support, significant stakeholder concerns, and an environment where costs have already risen precipitously due to the move from Day 1 to Day 2 operations.

**2. This Filing Is Not Ready For Acceptance By the Commission**

The Commission would certainly be justified in treating this filing as merely a conceptual proposal because the filing leaves too many open issues regarding: (1) the ASM design, (2) the associated costs, and (3) the need for Balancing Authority Area consolidation. Taking these points separately, this ASM design, while advertised as mimicking the co-optimization approach used in other regions has *never* been coded before by MISO's chosen vendor; nor has it been implemented in any geography as large and as diverse as the MISO footprint. As discussed in section B *infra*, significant questions remain as to the efficacy of this ASM design and whether this design makes sense for the Midwest region.

As explained by Dr. McNamara, under the current ancillary service methodology, prices are fixed and known in advance under the tariff.[22] He notes that certainty will be replaced with probability, and risk will be transferred from the host utility to the "market" and that "although the more efficient dispatch will likely put downward pressure on aggregate production costs across the footprint and possibly prices, there are several factors that are likely to create an

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[21] In March 28, 2007, MISO filed for an extension of time to comply with the Commission's Orders to improve the Automatic Mitigation Plan ("AMP") procedures. MISO states,

> "The development of the ASM and these other systems has stretched the resources of the Midwest ISO's software vendor. As a result of the ever increasing software demands from this vendor, the Midwest ISO has been in communication with the vendor's management to develop a specific timetable for implementing all necessary software changes, including those related to AMP." March 28, 2007 Motion of MISO in Docket No. ER04-691 at p. 4.

Clearly, MISO is prejudging acceptance of the ASM proposal even to the point of delaying work on improvements previously ordered by the Commission.

[22] Attachment E, Affidavit of Dr. McNamara at ¶ 15.

upward pressure on the price of both energy and reserves and may serve to increase costs."[23] He cites six factors that might actually lead to increases in ancillary service costs resulting from the proposed ASM:

- First is that currently, the price of reserves is related to average rather than marginal cost and under the proposed design there will be a single market clearing price. Assuming that in most cases, marginal cost is greater than average cost and that competitive pressure – in combination with the market monitoring and mitigation plan – will push offers to approximate marginal cost implies an upward pressure on prices.
- Second, integrating energy and reserves into the dispatch algorithm on a regional basis, while more efficient, is likely to produce greater uncertainty with regard to future prices. Variance around the mean price will increase and this should lead to higher overall prices as market participants include this risk in their forward price curves.
- Third, even assuming a perfectly executed dispatch, it is far more likely that the results will be less intuitive to market participants since the dispatch and commitment algorithms will have greater scope. It is rational to anticipate that participants will place a risk premium and hence a higher price on outcomes that are even more affected by algorithms that they only partially understand.
- Fourth, the exposure to dispatcher discretion and its potential effects is greater. Even if totally unwarranted, it would be prudent for a market participant to factor in a risk premium which accounts for what could happen as a result of dispatcher discretion.
- Fifth, to the extent that there are misunderstandings about either the rules or their implementation this will cause market participants to build in a risk premium potentially resulting in higher prices.
- Sixth, the increased uncertainty about prices will likely cause forward prices to rise and will put downward pressure on the term length of forward contracting. This in turn is likely to increase the reliance on the Day Ahead and Real Time energy markets at the expense of long-term bi-lateral contracting.[24]

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[23] Attachment E, Affidavit of Dr. McNamara at ¶ 17.

[24] Attachment E, Affidavit of Dr. McNamara at ¶ 17. In short, in evaluating whether the ASM proposal is likely to provide actual benefits to the market, we must look at how the market will respond to the new rules and not just whether the dispatch will be more efficient. It is almost tautological that regional co-optimization will result in a more efficient dispatch. If, however, as a result of the new market design uncertainty increases and this leads to even small increases in prices, then the predicted net benefits as compared to the current methodology – could be eroded substantially or even eliminated. *Id.* at ¶ 18.

Regarding the second point, associated costs, MISO makes much of the fact that a recent ICF study indicates "potential annualized gross benefits of $227 million."[25] However, one might conclude the ICF study results should be viewed by the Commission with extreme caution due to the lack of stakeholder involvement in the study design and prior MISO benefit forecasts. In MISO's 2004 Annual Report, MISO promised $713 Million worth of footprint benefits associated with the Day 2 Market.[26] Gross benefits realized to date are approximately $70 million (annualized). The original forecasted budget for the Day 2 Market was approximately $160 million, but the actual costs realized to date is $246.7 million. Thus, participants have realized approximately 10% of the benefits for almost 135% of the costs. As noted by Dr. McNamara, only 22% of the potential Day-2 market benefits identified in the ICF study have been realized from actual operation.[27] Thus, there are potentially $255 million of unrealized gross benefits from the current market -- without the creation of a single market for ancillary services or the filing of a single tariff change. More importantly, for the first year of operation the realized benefit from implementing the energy markets did not outweigh the Midwest ISO administrative costs to run those same markets.

Regarding the third point, MISO links its ASM proposal with BA consolidation. Yet, to date the MISO Transmission Owners have not voted to allow for BA consolidation as required by the "Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of the TEMT" ("BA Agreement"). Section 13.4 of the BA Agreement specifies that three-fourths of the transmission owners must vote to allow for changes to the BA Agreement that would affect a transfer of functionality to the MISO. As MISO states, "the BA

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25 MISO Transmittal Letter at 12.

26 *See* Attachment G, MISO 2004 Annual Report at p. 16.

27 Attachment E, Affidavit of Dr. McNamara at ¶ 5.

Agreement will require amendment to reflect a fundamental re-assignment of North American Electric Reliability Corporation ... (BA) responsibilities."[28] Thus, one of the underpinnings of this filing as proposed by MISO, agreement by the MISO Transmission Owners to hand over control area functionality to MISO over a 14 state region, has not occurred. For many transmission owners, this task is complicated by the fact that state approval, including authorization for IPL from the State of Indiana, is needed for control area functionality to be transferred from a transmission owner to MISO.

Moreover, as explained in the affidavit of Mr. Holtsclaw, contrary to MISO's representation to the Commission in its Addendum to the Filing of the Midwest Independent Transmission System Operator, Inc. Electric Tariff Filing To Reflect Ancillary Services Markets; Docket No. ER07-550-000, the issues associated with BA consolidation are not limited to concerns with specific operating protocols. Issues that remain to be resolved in order to achieve a positive vote on modifying the Balancing Authority Agreement include details on the operating protocols, issues with the current ASM design, particularly the must offer requirements, and a better understanding of the costs and benefits of the ASM.[29] Additionally, some signatories have indicated there may be regulatory issues with their state commission needing to approve the additional functional consolidations.[30] Thus, the ASM filing may create a picture of inevitability

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28 Addendum to ASM Filing at 2 (Mar. 1, 2007).

29 Attachment D, Affidavit of Mr. Holtsclaw at ¶ 10.

30 *Id.* As Mr. Holtsclaw explains the BA consolidation will not result in significant administrative cost savings. There are 388 specific requirements that a balancing authority must comply with as defined in the current NERC reliability standards. As currently proposed, the MISO BA would have 137 requirements that only they would have to comply with and the existing BA's would have 7 that only they would be solely responsible for. However, this leaves 244 requirements that both MISO and the existing BA's would be required to comply with. While there may be some minor cost savings for the existing BA's, it will not likely result in any personnel reductions. IPL will still have to comply with the majority of the NERC requirements and will still have to perform some oversight functions of MISO to assure that the IPL system is being operated in a reliable manner.

and momentum regarding this market re-design proposal, where no inevitability or momentum exist.

### 3. Rejecting the Filing Without Prejudice At This Time Will Allow Midwest Stakeholders To Focus On Other Required Initiatives.

As discussed in the recent orders on transmission cost allocation, the MISO Transmission Owners are required to submit a comprehensive post-transition period transmission rates filing in August 2007.[31] In addition to filing transmission rates covering MISO (for both new and existing facilities), the MISO Transmission Owners are also required to file a new transmission rate design for MISO-PJM transmission rates.[32] The Commission has previously spared MISO stakeholders from having to navigate a fundamental change in energy market design and an overhaul of transmission pricing.[33]

In addition to transmission rates, other significant initiatives will also require significant stakeholder attention. For example, MISO plans a demand response filing prior to this summer. Additionally, MISO has recently begun implementing new ARC procedures. As described in the MISO transmittal letter, the Contingency Reserve Sharing Group Agreement ("Midwest CRSG Agreement") has already been approved and is currently in effect. Transmittal Letter at 42. As MISO states, "the expected savings resulting from the coordination of the reserve sharing arrangement are already being realized for the benefit of the signatories to the Midwest CRSG Agreement. *Id.* Curiously, no explanation is given in the ASM filing as to why stakeholders

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31 *See Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,208 at P 28 (2007); *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,209 at P 17 (2007).

32 *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168 at P 62 (2004).

33 *Id.* at P 65 (rejecting flow-based transmission pricing proposal during period of time leading up to move from Day 1 to Day 2 Market operations).

cannot continue to gain experience with the CRSG in order to evaluate whether the incremental benefits associated with that significant program are such that the entire ASM proposal is unwarranted. Thus, the Commission should allow MISO and its stakeholders to focus on the full panoply of existing initiatives, without forcing them to attempt to do so against the backdrop of a market design that will fundamentally change.

### 4. The ASM Proposal Cannot Be Permitted To Move Forward Based On MISO's Cost-Benefit Projections

Taking additional time to develop an ASM that can be cost-justified is the proper approach for MISO's customers. MISO projects potential annual benefits of ASM to be $113 million to $208 million with capital costs of approximately $65 million and with ongoing operation costs of approximately 25 million.[34] Additionally, some of the capital costs of the project are already sunk costs and arguably associated with costs that would be necessary without the ASM. Unfortunately, past MISO cost/benefit projections have been wildly optimistic. For instance, the cost estimates for establishing the Day 2 energy market increased from initial projections of between $90 million to $100 million to later estimates of $244.9 million. MISO's 2004 annual report promised $713 million in annual savings from the operation of a Day 2 energy market.[35] The gross footprint wide benefits realized to date as stated in the ICF study are $70 million. Therefore to date the costs significantly out weigh the gross benefits. On a net basis, only using the costs at the footprint wide basis of schedules 16 and 17 and ignoring Schedule 10 and the incremental costs shouldered directly by the members, the costs are elevated to $369.9 million vs. a realized benefit of only $70 million - a loss of approximately $300 million. Thus, while FERC has encouraged utilities to join RTOs,

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[34] *See* Attachment F, Presentation at EEI CEO Meeting dated March 22, 2007.

[35] A copy of the annual report is provided as Attachment G.

participation in MISO to date has not delivered customer benefits in excess of the costs. In fact the costs are magnitudes greater than the benefits.[36]

In responding to a complaint demanding a joint MISO-PJM economic dispatch, the Commission rejected the complaint, partly on the grounds that the measure could not be cost justified, especially in light of the fact that many benefits could be delivered through less costly and less extreme measures.[37] The same is true with respect to ASM; incremental benefits can be derived through targeted steps that are far less costly. IPL emphasizes that the ASM represents an unproven market design -- this market design has never been used before. Thus, in effect, MISO is asking the Commission to allow it to take a significant gamble with consumer welfare.

High administrative costs, problems with the manner in which losses are assessed and credited, high uplift charges, and high implementation and other costs should call for regulators to take a cautious (perhaps skeptical) approach to further costly changes.[38] While MISO and other Market Participants will eagerly point out "yes, but" the additional savings will come once you give us the green light for this new market design, IPL draws a different conclusion. In its management of the oversight of the ASM project, MISO does not appear to be acting as a prudent public entity responsible to provide service efficiently and effectively. Good business practice would caution against embarking on a new complex and expensive endeavor absent far greater assurance of an appropriate return. As explained by Dr. McNamara, the ASM project is not needed to enhance reliability, competitiveness of the Energy market, or the independence of

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[36] It should be noted that this discussion does not include internal company costs (*i.e.*, costs incurred outside of the costs recovered through MISO charges).

[37] *Wisconsin Public Service Corp.*, 118 FERC ¶ 61,089 at P 36, 37, 44 (Feb. 8, 2007) (finding that "many of the potential benefits associated with a single system dispatch may be achieved through less costly incremental steps) (emphasis added).

[38] *See also* Attachment A, Affidavit of Mr. Bentley at ¶ 16-18.

the MISO.[39] The overriding rationale is a *theoretical* cost benefit. Yet, there is good cause to doubt the viability of these predictions. The more appropriate reaction may be "fool me once, shame on you, fool me twice, shame on me."

The new ASM will lead to significant new cost burdens and benefits that do not come close to MISO's and ICF's rosy projections. While the Commission has "talked the talk" regarding the need for RTO cost oversight,[40] this case gives the Commission the opportunity to "walk the walk." The Commission can send a message to all RTOs that expensive new initiatives must be strongly supported and cost justified before the Commission will force consumers to pay for those projects. The "days of wine and roses" for massive new cost outlays for RTOs should be over.

Most of the incremental benefits associated with improvements to the existing Day 2 Market platform can likely be achieved through the implementation of ARC procedures and other targeted improvements. Consistent with the Commission's theme that more value can be delivered to consumers through reform rather than revolution, the Commission should reject this filing without prejudice and give ongoing incremental improvements a chance to succeed.

Even assuming *arguendo* that there are significant regional benefits that can be captured, these benefits may come at a significant expense to particular market participants, especially if cost causation is not followed. One Market Participant within the region has already departed. More may choose to exit if future MISO initiatives result in actual costs that exceed actual benefits.

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39 Attachment E, Affidavit of Dr. McNamara at ¶¶ 8-10.

40 *See generally Accounting and Financial Reporting for Public Utilities Including RTOs*, Docket No. RM04-12-000.

### 5. Protection Of Customers Demands That Market Design Be Correct, Rather Than Fast

#### a. Past Experience

Consumers have been described as the Commission's primary constituency.[41] Experience makes it clear that consumers are best protected with careful consideration and planning and measured progress rather than an ambitious but hasty rush to an unproven market design with potential harmful consequences. Consumer protection is not advanced by a theoretical market construct, but rather by reliable service at economic prices. California may provide the best example of a rushed market design leading to vast consumer harm, as it (coupled with illegal conduct by certain market participants) engendered the California Energy Crisis.[42] However, the New York market also experienced an ancillary services market meltdown shortly after the New York Independent System Operator, Inc. began operations,

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41 *Maryland People's Counsel v. FERC*, 761 F.2d 780, 781 (D.C. Cir. 1985) (citations omitted).

42 In 1998, the Commission rejected the CAISO's request that suppliers be required to demonstrate on a time-differentiated basis that they lacked market power at all times and under all conditions. Less than a month later, the CAISO was forced, due to market conditions, to accept bids of $9,999/mw for five hours on July 13, 1998, resulting in costs of approximately $12.5 million. This led the CAISO to seek authorization for an immediate price cap which remained in place until superseded by the mitigation measures developed by the Commission as a result of the 2000-01 California Energy Crisis. In 2000, the Commission rejected an interim proposal by the CAISO to mitigate local market power and instead focused solely on requiring the CAISO to fix the congestion management system existing at the time; *see California Independent System Operator Corporation*, 91 FERC ¶ 61,026 at 61,985-86 (April 12, 2000). The near-immediate result was "several cases of potential physical withholding (unit outages) and economic withholding (bids at or near the $750 price cap) . . . which have had significant financial impacts." See May 12, 2000 Market Analysis Report to the CAISO Market Issues ADR Committee at p. 9.

primarily because the New York market model incorrectly modeled a pumped storage unit.[43] In the case of a market meltdown, usually all it takes is a one time price spike to wipe out a year's worth of benefits to customers. Thus, it is appropriate for the Commission to consider MISO's filing as a conceptual proposal, provide guidance and allow the stakeholders and MISO to proceed in a manner that minimizes the chances for harmful consequences.

As discussed earlier, the Commission issued guidance orders prior to permitting MISO's Day 2 Market to start up, and even when Day 2 operations were authorized, the Commission required extensive transitional safeguards,[44] none of which have been made part of the current proposal.

Importantly, Dr. McNamara discusses why, based on the specific circumstances that exist in the Midwest, simultaneous co-optimization may not produce the benefits that might be expected in other regions.

> One other factor that should be mentioned is that the Midwest ISO markets were not established after a history of "pooling" arrangements. In effect, the market is a patchwork quilt of somewhat isolated electrical islands. Two relevant characteristics arise as a result of this history. First, relative to other RTOs that evolved from "power pools" the Midwest has an extraordinarily high amount of baseload generation capacity. Hence the value of re-dispatch through regional security constrained economic dispatch is limited. Second, the physical transmission system does not have the degree of interconnection that is present in other markets. While LMP-based dispatch conducted by the Midwest ISO will

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[43] After NYISO began operations, prices spiked from averages of $1.04 per megawatt hour (MWH) in December 1999 to an average of $65.57 in February 2000, with a high of $302 that month. Also at that time, the quantity of non-spinning reserve that suppliers offered into the market decreased. The Commission determined that NYISO's practice of procuring spinning and non-spinning reserves from generators only located on the east side of an east-west constraint contributed to the price anomalies, and directed NYISO to develop procedures to maximize access to western suppliers of reserves. In addition, the Commission stated that one reason for the NSR price increases was NYISO's practice of allowing the highest bid for NSR to set the market clearing price for NSR under certain circumstances. Last, the Commission stated that if NYISO had modeled its software to include the Blenheim-Gilboa storage facility, the market concentration levels would have been lowered. The Commission denied retroactive price relief and stated that changes should be prospective. *New York Independent System Operator, Inc.*, 88 FERC ¶ 61,228 (1999), *on rehearing*, 110 FERC ¶ 61,244 (2005), *rehearing denied*, 113 FERC ¶ 61,155 (2005).

[44] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 at P 36-40 (Aug. 6, 2004) (describing in general terms six protective measures associated with Day 2 market start-up).

> create better price signals resulting in more efficient investment that will ultimately produce a more integrated system, until this occurs, participants should condition their expectations regarding the extent to which centralized, and now potentially co-optimized, dispatch and commitment of the existing physical assets can deliver benefits. In the final analysis perhaps the greatest initial benefit from implementing the Day 2 energy markets arises not so much from gains in operational efficiencies but from the creation of a robust transparent price signal that better informs investment. And if this is true, there is even more reason to make sure the current market is performing as well as it can and that changes to the design are evaluated at least as much by their effects on operational efficiency as they are on how they might impact the wider marketplace.[45]

Thus, there is no reason to proceed with the ASM at this time, without further analysis of the specific circumstances of the Midwest. Theory is not enough. The actual impacts of the new design must be understood.

**b. Arbitrary Start Date**

MISO states that Commission action is needed in order to allow for the ASM market to start-up by Spring 2008.[46] Yet, MISO provides no support for considering this time frame to be a "magic" time frame. If the ASM does not start-up during the Spring of 2008, Day 2 operations will continue. In other words, a market that is already functioning will continue functioning on an improved basis with the use of the Contingency Reserves Agreement and ARC procedure. MISO's aggressive implementation schedule lacks sufficient justification. The proposed implementation date has become controlling rather than sound policy and reasoned cost/benefit analysis. MISO and market participants are being forced to design and procure systems -- without even waiting for Commission approval. The Commission should send a message to MISO (and all RTOs) that such insouciance will not be tolerated.

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45 Attachment E, Affidavit of Dr. McNamara at ¶ 19.

46 MISO Transmittal Letter at 1, 42-43.

### 6. Summary Of The Big Picture

In summary, the Commission should continue to enhance the Day 2 Market design through targeted reforms to the market model that are modest in cost, but significant in customer benefit. The Commission should provide time to realize the benefits of the Contingency Reserve Agreement and ARC procedures. The potential financial and operational impact upon members and customers should be fully considered by MISO and the Commission prior to implementation of any new market re-design. An appropriate benefits/cost analysis overseen by the Commission (rather than a self-commissioned study, without involvement of market participants) should be undertaken, and any new market re-design proposals should be conditioned on the results.

## B. DISCUSSION OF SPECIFIC CONCERNS

### 1. The Proposed Simultaneous Optimization May Not Be Optimal and May Result In Increased Uplift Charges

IPL is concerned that MISO proposes to employ a simultaneous co-optimization methodology that has not been attempted by its chosen vendor and had not been implemented across a geographic area as large as the MISO footprint. There is significant systems and market risk associated with this project. Moreover, IPL understands that the MISO proposes to run the optimization based on a ten minute look-ahead timeframe. This extremely short period creates the real possibility of higher uplift charges due to an inefficient dispatch that fails to account for potentially lower cost, longer lead time units.

As the Commission is well aware of the potential problem that failing to consider potentially lower cost but longer starting units can have on a simultaneous co-optimized dispatch. In California, the Commission required the CAISO to make a compliance filing demonstrating how it would implement Section 27.4.1 of its tariff which called for the CAISO to use its security constrained unit commitment algorithm on a 48-hour basis to commit extremely long start units that can respond in that timeframe.[47]

As explained in the affidavit of Ms. Franks, IPL understands that most regional transmission providers utilize a twenty-minute look ahead, double that of the MISO.[48] The shortened timeframe can cause additional resources to be dispatched to meet demand and system requirements. These resources would have additional uplift costs that will be socialized to Market Participants on a load-ratio share basis.[49]

In addition, MISO's optimization does not appear to allow a potentially lower cost but higher quality service to substitute for a more expensive inferior service. For example under Section 8.2.3.5 of the MRTU Tariff the CAISO engages in a "rational buyer" approach under which it can purchase more of a service such as regulation if it is available at a lower price than a lower quality service such as non-spinning reserve. It is not clear that MISO's optimization will adopt the same rational buyer methodology.

Furthermore, the complicated algorithms will limit the ability of stakeholders to audit the results to determine if the ASM is working properly. Shadowing the clearing prices will be an extremely difficult and time consuming task.

In summary, the proposed simultaneous co-optimization program is extremely complex and may produce unintended inefficiencies and unjust prices. Moreover, even if it performs as

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47 *California Independent System Operator Corp.*, 116 FERC 61,274 (2006) at P 125 ("We, therefore, direct the CAISO to make a compliance filing within 60 days of the date of this order explaining how it will determine the commitment of extremely long start resources and how such commitment will be integrated with the normal day-ahead commitment process"). The CAISO had explained that MRTU Tariff section 27.4.1 calls for the CAISO to use its security constrained unit commitment algorithm on a 48-hour basis to commit extremely long start units that can respond in that timeframe. *Id.* at P 124.

48 *See* Attachment B, Affidavit of Ms. Franks at ¶ 24.

49 When this issue was raised in stakeholder forums, MISO stated that a move to a 20 minute forward look would increase the resolution time beyond acceptable limits. Increasing uplift from this stakeholder's point of view is also beyond acceptable limits. *See* Attachment B, Affidavit of Ms. Franks at ¶ 24.

intended, co-optimization on a footprint wide basis may produce an uneven pattern of benefits. Current low cost providers may see their costs actually increase due to the socialization of uplift charges while the high cost providers' costs will decrease.[50]

### 2. The Process for Establishing or Changing Ancillary Service Zones Is Not Well Developed and Is Subject To Change on Short Notice

In the February 15, 2007 filing, MISO proposes to evaluate Reserve Zones *daily*, and reconfigure and/or update *as required*, according to MISO this "appropriately balances the need for certainty with the need to ensure that Operating Reserve dispersion and deliverability requirements accurately reflect current system topology."[51] IPL disagrees. In order for load serving entities to properly manage their ancillary service procurement, they must have the ability to know with far greater certainty the locational requirements they are operating under.

MISO's filing fails to specify the criteria under which it will modify the Reserve Zones. The filing also fails to discuss the potential risk that the smaller zones could result in the exercise of locational market power. Mr. Jones' Testimony describes MISO's proposed methodology for determining Reserve Zones and indicates that in a test case four Reserve Zones were identified.[52] The methodology, however, is not included in the filed tariff language.

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[50] As explained in the Affidavit of Mr. Bentley, MISO has indicated its belief that the financial concern of vertically integrated utilities is a concern of recovery. For IPL, this is not the primary issue. The concern is that whatever market for ancillary services in implemented actually provides benefits to customers in excess of the costs. Simply stated – if customers are truly benefiting through participation in a MISO market, then operating cost recovery is not problematic. The concern is that extremely complex and expensive new programs are being proposed with potential significant detrimental ratepayer impacts, without full consideration of ways the existing market can be improved at far less cost.

[51] MISO Transmittal Letter at p. 27.

[52] Exhibit E to MISO Filing at p. 49-50.

As explained by Ms. Franks, dynamic zones increase the difficulty of shadowing the clearing prices. More significantly, daily changes can make hedging and forward procurement of ancillary services extremely difficult.[53]

The Commission must act to provide greater stability on the determination of Reserve Zones. MISO must be ordered to: (1) identify a defined set of zones that would not be modified unless specific conditions exist; (2) develop, in advance and include in the tariff, the criteria that would result in modification to the Reserve Zones; and (3) provide Market Participants sufficient time to make procurement decisions in advance of any change to modification of the zone.

### 3. There Is a Need To Have a Fully-Protective Self-Supply Option

As noted above, one of the success criteria identified by the ASTF was that participation in the ASM be voluntary. Indeed, this belief was so important that it is reflected in a second criteria – the availability of self-supply. If a market is functioning properly and providing benefits to participants, they will participate, without coercion.

While MISO's market design provides for the ability to *self schedule*, that is not equivalent to *self-provision*. When an entity self-schedules it is a price taker and is subject to congestion and losses. In contrast, self provision provides the state regulated utility (or other market participant) with the ability to continue to reliability serve its customers by in effect opting out of the ancillary services market for a specified period of time.

It has been the Commission's mandate since order No. 888, that "Transmission providers are required to facilitate efforts by customers to meet Operating Reserve obligations with their own generating resources."[54] The ASM, as proposed, violates this principle. Cost exposure

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53 See Attachment B, Affidavit of Ms. Franks at ¶ 30.

54 Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, (May 10, 1996), FERC Stats. & Regs. P31,036 (1996) at 61 FR 21588.

results from the fact that self-supplied generation is paid a locational price at the applicable Commercial Pricing Node but self-scheduled loads are subject to costs on a Market Load Ratio Share basis.[55] The difference between a separate, self-supply option and mandating that all transactions be run through the market are not semantic. Only by the ability to opt out can an entity protect itself from price exposure and socialized uplift charges.

#### 4. The Scarcity Pricing Proposal Could Result In Excessive Costs To Consumers

MISO proposes to implement a minimum Operating Reserve Demand Curve Scarcity Price based on the sum of the Energy Offer cap and the Contingency Reserve Offer cap. The minimum Operating Reserve Scarcity Price is \$1,100/MWh and the proposed maximum on the Demand Curve is \$2,500/MWh. The proposed maximum Operating Reserve Demand Curve value is based on the "Value Of Lost Load" determined to be \$3,500/MWh.[56] MISO's proposed scarcity prices, exceed those used by other regional transmission providers, including those who do not operate capacity markets, and will result in unjust and unreasonable costs. The Commission should limit scarcity prices to no more than \$1,000/MWh.

In the California MRTU Order, the Commission stated that it had "adopted a uniform policy on energy bid caps because this market design feature, in combination with other market behavioral rules, has been shown to prevent the exercise of market power.[57] The Commission noted that the \$1,000/MWh value "has operationally been shown to provide LSEs with an

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55 Resources will be paid a zonal clearing price for operating reserve capability while load will pay on a MISO wide load ratio share basis. Thus, a LSE which self-schedules its own resources can receive less revenue for its self-supply than it will pay.

56 MISO Transmittal Letter at page 24.

57 *California Independent System Operator Corp.*, 116 FERC 61,274 at P 1020 (2006).

incentive to enter into long-term contracts and new investment in infrastructure" and was appropriate in times of scarcity.[58]

In Docket No. ER03-854, David Patton filed an affidavit in support of ISO New England's scarcity price limit of $1,000/MWh.[59] Under the PJM settlement, whenever any of six measures of scarcity occur in any of five designated regions, the unit-specific offer caps of all generators in that region are lifted so that all generators are free to increase their offers up to the PJM-wide $1,000 offer cap, and the highest accepted offer may set the price in the region.[60] In an apparent effort to differentiate between the scarcity pricing levels in the MISO filing and those utilized elsewhere, MISO contends that these markets also have centralized capacity markets to ensure resource adequacy[61] and that "for the Midwest, the economic signals provided by the energy and ancillary service markets are the primary source of economic signals to maintain resource adequacy."[62] This statement does not withstand scrutiny. California does not have a centralized capacity market. Nevertheless, the Commission has accepted the same $1,000 MWh scarcity pricing ceiling that has been approved elsewhere.

The primary impetus to the construction of generation resources in the Midwest is not through the pricing of reserves but though the establishment of appropriate planning reserve margins and state oversight of utility resource adequacy programs. Financing of new projects depends on the steady relationship between the long-term commitment of load serving entities to pay the capital costs either under contract or through rate recovery. Projects are unlikely to be

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58 *Id.*

59 Affidavit of David B. Patton in ISO-NE's May 15, 2003 filing in Docket No. ER03-854-000 at paras. 13-19.

60 *See PJM Interconnection, LLC*, 113 FERC ¶ 63,038 (2005). The Commission approved the PJM settlement on January 27, 2006. *PJM Interconnection, LLC*, 114 FERC ¶ 61,076 (2006).

61 MISO Exhibit No. H, Affidavit of Mr. Patton at p. 11.

62 *Id.*

built in response to short term "signals." Thus, a price of $3,500 MWh does not accomplish the stated objective of providing an incentive for new construction but presents a mere transfer of wealth from customers to suppliers.

The MISO has failed to properly support its scarcity pricing proposal. Consistent with the limits imposed in all other RTOs, the scarcity price should be capped at $1,000 MWh. Failure to impose such limits will result in unreasonable pricing in the ancillary service markets and further erode public trust in utility markets. During the California crises, when Duke Energy submitted a bid of $3,880/MWh, the Commission stated that it would "not tolerate abuse of market power and anticompetitive bidding behavior," threatened to revoke their market based rate authorization and ordered refunds of amounts above $273/MWh.[63] There is a thin line between the economists definition of scarcity and the reality born by load serving utilities and their state regulators when headlines are screaming about stratospheric prices. MISO's scarcity proposal should be rejected. There is no basis, particularly at the start of a new market, to expose customers to risks above and beyond those in other regions.

### 5. The MISO Filing Fails To Consider State Rate Impacts and Timing

In his testimony, Michael Robinson, MISO's Manager of Market Development, describes the formation of "various subgroups, according to functional responsibilities."[64] He identifies the ASM State Ratemaking Study Group as the group tasked with "assessing and gathering information on how the costs of Operating Reserves are currently recovered through rates and analyzing the potential impact on revenues of the proposed Ancillary Service Market Design,

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63 *San Diego Gas & Electric Company*, et al. 95 FERC ¶ 61,418 at 62, 56 (2001).

64 MISO Exhibit G at p. 6.

clearing prices and charge types."[65] According, to Mr. Robinson, MISO's own witness, the group "*is in its formative stages*."[66]

While IPL appreciates the honesty of this statement, it serves to illustrate the profound frustration and difficulty in participating in MISO's stakeholder process. "Build it and they will come"[67] (or, as in this case, build it and mandate that they come) may work in the movies, but it is no way to implement a market. The haphazard nature of development of this ASM is highlighted by Mr. Robinson's statement. The practical effect that the design will have on entities that must function in the new marketplace appears to be an after thought.

As explained by Ms. Franks in her affidavit, other than certain LECG presentations in the ASTF, MISO has yet to provide in any stakeholder forum, an analysis of the magnitude of the clearing prices under various scenarios. Some scenarios of possible clearing prices will be those where clearing prices approach the value of lost load of $3500/MWh. Without this information, participants have no way to determine the magnitude of financial impact to the utilities and their customers. Thus, regulated utilities have no effective information with which to make a business decision to move toward a rate case. Neither do they have the requisite information to assess benefits and costs that accrue to their customers.

As Ms. Franks explains, the information collected by the ASM State Ratemaking Study Group shows that in 7 out of the 11 states in the market footprint, the current state recovery mechanisms are insufficient to address the clearing price based ancillary services and the capital and operating costs associated with the ASM. Thus, for now, then those costs are trapped. The chart below, illustrates this problem.

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65 *Id.*

66 *Id.* (Emphasis added.)

67 Quoting the character Terrence Mann (played by James Earl Jones) in *Field of Dreams* (Universal Pictures 1989).

| State | Challenges | Remedy |
|---|---|---|
| Illinois | None | ASM costs passed to auction suppliers |
| Indiana | No current means for cost recovery of ASM costs | Rate Case |
| Iowa | AS cost included in base rate | Probably will require rate case |
| Kentucky | No current means for cost recovery | Rate Case |
| Michigan | May be credited to rate base in the form of fuel and purchased power | Subject to annual review |
| Minnesota | AS cost included in base rate | Probably will require rate case |
| Missouri | Bundled in rate base | Probably will require rate case |
| North Dakota | Bundled in rate base | Probably will require rate case |
| Ohio | Mechanism assumes costs are transmission | Define as transmission services |
| Pennsylvania | | |
| South Dakota | Bundled in rate base | Probably will require rate case |
| Wisconsin | Forecasting ASM related costs with any degree of accuracy<br>AS cost included in base rate | Unknown<br>If in base rate will require rate case |

The Commission should not permit the ASM to go into effect until the ASM State Ratemaking Group provides an implementation plan with an appropriate timeline. It is unreasonable to proceed with a project of this size and expense without proper regard for implementation by member utilities, specifically their need to coordinate with their respective state authorities. The Commission must not put disincentives on utilities to participate in RTOs if through such participation they will be exposed to trapped costs.

### 6. The Must Offer Obligation Intrudes Into Areas of State Authority Over Reserves

As explained by Ms. Franks, it was not until approximately one month before the original schedule for filing of the tariff sheets that MISO mentioned the "must offer" obligation. Until that time, IPL assumed that the success criteria developed by the ASTF on September 22, 2005 would be honored and incorporated into the design. As emphasized above, that criteria included *voluntary* participation.

IPL is concerned that the must offer obligation is in conflict with its responsibilities to maintain its own reserve obligation. At least until Indiana authorities approve any changes to the existing Balancing Authority Area configuration and responsibilities, IPL has the responsibility to maintain its reserve obligation for its Balancing Authority Area, a responsibility that is inconsistent with a must offer obligation.

### 7. The Filing Violates Cost Causation Principles

The combination of complexity in the design and in certain of the draft tariff language and incompleteness (such as the absence of business practice manuals) makes it difficult to understand the relationship between cost incurrence and cost payments reflected in the filing. The Commission's cost causation principle requires that costs be assigned to the entity or entities responsible for their incurrence.[68] IPL is concerned that MISO's costs of ancillary procurement are to be charged on a Market Load Ratio Share basis even though certain Reserve Zones might have vastly different prices due to scarcity prices or other factors.

Market Load Ratio Share under ASM is defined as "the factor calculated as the Actual Energy Withdrawals plus Export Schedules of a Market Participant at all Commercial Pricing Nodes divided by the sum of all the Actual Energy Withdrawals plus Export Schedules at all Commercial Pricing Nodes in the Transmission Provider Region." In essence, the term is tantamount to total socialization of costs. If all entities must bear a Market Load Ratio Share, even if they have self supplied and other Market Participants are responsible for additional costs

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68 *California Independent System Operator Corp.*, 101 FERC ¶ 61,219 at P 17, *order on clarification*, 103 FERC ¶ 61,042 (2003)

such as the need for scarcity prices, the ASM must be rejected for its unjust and unreasonable cost allocation methodology.

As Professor Hogan stated at the Commission's recent conference on Competition in Wholesale Power Markets:

> "You cannot be socializing the cost across these RTOs and leave them where everybody who's below average cost can leave because they will and they should in their own interest. But it's obviously not in the interest of the country and I think that's a fundamental choice between how you're going to approach these problems. . . It better be out on the table and something that you're going to deal with. . . . [I]f you allow the current ones to unravel because you lay your costs and mandates on top of them, but you say you can leave voluntarily if you don't like it, well, good luck."[69]

As proposed, the broad use of Market Load Ratio Share as a cost allocation methodology violates cost causation principles. Entities that contribute to scarcity conditions are able to shift the burden of their under supply.

### 8. The ASM Proposal Is Incomplete Without the BPMs that Will Implement the New Design and MISO Must Develop a Formalized Process for BPM Revisions

IPL is concerned that the Business Practice Manuals needed to implement the new ASM have not been developed. Consistent with its approach to implementation of new market programs for other RTOs, the Commission should require that MISO work with stakeholders and have in place, *prior to the implementation of the ASM*, the necessary Business Practice Manuals. In addition, the Commission should require MISO to formalize, in its tariff a process for updating or revising the manuals.

In its order on the California market redesign, the Commission recognized the importance of Business Practice Manuals; the importance of stakeholder involvement in their preparation,

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69 Transcript of February 27, 2007 conference in Docket No. AD07-7 at 133-4.

and the likelihood that the manual development process would lead to additional refinements to the tariff as the implementation details were finalized. Accordingly, the Commission directed the CAISO to work with stakeholders to develop the Business Practice Manuals and to file no later than 180 days before the effective date of the new market, any necessary additions to the tariff.[70] The Commission should impose similar requirements on MISO with respect to the new ASM.

In addition, the Commission "direct[ed] the CAISO to file its proposed tariff language regarding a standard, formalized process for amending the Business Practice Manuals."[71] Again, the Commission should impose a similar requirement on the MISO. The Commission is well-aware of the importance of Business Practice Manuals and the potential for conflict between the manuals and the tariff.[72] Given the complexity of MISO's markets and systems and the potential for significant impacts to stakeholders, absent exigent circumstances, changes to the manuals should be done through an open and thorough process.

70 *California Independent System Operator Corp.*, 116 FERC 61,274 at P 1370 ("We direct the CAISO to continue working with stakeholders to develop the Business Practice Manuals. Once this process is completed, we direct the CAISO to file, within 30 days of the completion of the Business Practice Manuals stakeholder process, but no later than 180 days before the effective date of MRTU Release 1, any necessary additions to the MRTU Tariff. We will then schedule a period of comments; after which, we direct Commission staff to convene a technical conference to assist us in the determination of which practices or details remaining in the Business Practice Manuals might appropriately belong in the MRTU Tariff").

71 *California Independent System Operator Corp.*, 116 FERC 61,274 at P 1371 (2006).

72 *See Midwest Independent System Operator*, 115 FERC 61,108 at PP 12-29 (2006), *on reh'g* 117 FERC 61,113 (2006).

### 9. Uninstructed Deviation Penalties

In Section 40.3.4, MISO has proposed modifications to the provision on uninstructed deviations by generators. Specifically, MISO has significantly narrowed the proposed deviation band from 10% to 4% and proposed to apply it on a five minute interval.

IPL is concerned that the narrower bands may have the detrimental effect of promoting the use of more expensive resources in lieu of older coal-fired units that might expose participants to potential penalties or uninstructed deviation charges. IPL understands the need to promote accurate generator responsiveness, but MISO does not cite actual instances of abuse of the existing uninstructed deviation methodology, but rather a hypothetical "free rider" problem.[73] The problem arises that different units have different operational capabilities to follow MISO's dispatch instructions. Whereas for certain units the proposed 4% deviation band many not present an operational challenge, other units may require greater bands due to their limitations. These units are not "free riders" but were designed for a different operating environment that did not require the ability to respond to different dispatch points with on a five minute interval basis. The Commission should require any ASM proposal to take into account these different operational characteristics that require deviation bands of more than 4 % for certain types of facilities.

### 10. MISO's DSM Proposal Is Improperly Designed and May Undermine Existing State Programs

In its filing letter and testimony, MISO takes great credit that it has "expand[ed] the opportunities for Demand Response Resources to participate in the Energy and Ancillary Service Markets on a basis comparable to Generation Resources and Consistent with Applicable

[73] MISO Exhibit No. E at 76-78.

Reliability Standards."[74] This statement may well be true as far as it goes MISO has developed two categories of DSM (Type 1 and Type 2) and treated them based on their operating principles or limitations as Generation. This does not mean, however, that the proposed approach to DSM reflected in the ASM proposal is just and reasonable or will lead to a more effective demand response.

While everyone wants to encourage DSM participation, it is not sufficient to overlook the difficult issues that arise from separate jurisdictions. State oversight of DSM is integral to their authority over resource adequacy and bundled retail rates. Existing DSM programs can reduce utilities' forecasted loads – in other words the utility can take credit for the DSM program to reduce the amount of load it needs to consider for purposes of maintaining a planning reserve margin. Furthermore, DSM programs have been integrated into retail rate structures and allocation of the utility's cost-of-service among different customer classifications.

As described in the affidavit of Mr. Haselden, IPL has ten existing rates and riders whose participants can be considered as DSM assets.[75] These rates and riders were designed to be responsive to system reliability events and are generally structured such that a customer receives a payment or different rate in return for performing a demand response function such as curtailing load or self-generating. As Mr. Haselden further explains, with one exception, the existing DSM programs are not conducive to participation in the ASM.[76]

Before demand side resources could better participate in the ASM, the business rules and a regulatory framework acceptable to all parties would also need to be negotiated and approved on a state level. Moreover, this would need to be done in such a way as to not discourage

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74 MISO Transmittal Letter at p. 26.

75 Attachment C, Affidavit of Mr. Haselden at ¶ 9.

76 Id.

participation in existing programs. For if this were to happen, IPL would need to consider these loads as firm loads with the result that IPL would need to acquire sufficient capacity and reserves to serve them since there will no longer be an *obligation* for the customer to perform the demand response function when requested.

As noted by Mr. Haselden, MISO appears to have the cart before the horse when it comes to DSM.[77] The critical work of framing the rules and structure between the participant, the load serving entity, and the market operator must be crafted first rather than the top down, one (or rather two) size fits all approach taken by MISO of creating a theoretical market in which few can reasonably participate.[78]

### 11. There Is a Need for an Emergency Reversal Plan and Price Correction

In a project of the size and complexity of the ASM, it is only prudent that MISO be required to have a plan of reversion in case of a major failure of the Day 3 market. Nothing in the filing letter or the MISO testimony discusses the course of action MISO would undertake if, despite all of the pre-operational testing, the market fails to operate as intended. MISO must be required to have a reversion plan in case of major failure.

The Commission must also assure that MISO has the appropriate authority to correct prices in the event that implementation problems result in unreasonable prices due to market design flaws or MISO implementation errors. While the Commission has approved general price correction authority for MISO, IPL is concerned that the existing authorization will not sufficiently protect customers if the ASM does not function as planned and if gaming opportunities or unanticipated scarcity pricing problems materialize.

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77 *Id.* at ¶ 14.

78 *Id.*

### 12. Other Issues

#### a. The Commission Should Halt MISO From Requiring Market Participants To Execute Agreements Relating to the ASM Prior To Commission Action

IPL is concerned that MISO has been taking a number of actions that essentially presume its ASM filing will be accepted by the Commission. This includes expending significant sums to design and code the software, prior to the Commission decision. In addition as discussed in the affidavit of Mr. Holtsclaw, MISO has required participants to execute agreements such as the Balancing Authority Agreement to be eligible for cost reimbursement under the ASM project. Most significantly, MISO has requested Market Participants to sign a "Commitment to Provide Operating Reserves."

IPL maintains that it is improper for MISO to presume Commission acceptance of its submission. Accordingly, the Commission should order MISO to cease from requiring the execution of any agreements predicated on the ASM at this time.

#### b. The Commission Must Assure that Any MISO ASM Has Been Adequately Tested Prior To Implementation.

The filing presents a wholly inadequate description of the planned testing program prior to implementation. The "schedule" presented in Figure 1 of the Filing Letter appears highly compressed and highly suspect. Consistent with its recent approach for another regional transmission provider the Commission should, at a minimum specify that the ASM be implemented only when the MISO's and the market participants' "systems, software and tools have been fully tested and the [MISO] and its stakeholders are confident that [the ASM] will function properly when implemented," and that the Commission is "committed to a sound and orderly [ASM] implementation plan and will not allow that to be sacrificed for the sake of expedience."[79] The Commission should also: (1) require the MISO to work with Market Participants to develop readiness criteria that would need to be met prior to the implementation of any ASM;[80] (2) require the MISO to certify to the Commission, at least sixty days prior to implementation of the ASM that MISO and Market Participants are ready to implement the new market;[81] and (3) require a quarterly evaluation and reporting requirement to assess the functioning of the ASM after implementation.[82]

IPL has actively participated in the MISO and certainly does not seek to impede improvement in the markets. But change does not equate to benefit. The enormous cost and complexity of the ASM being imposed on Market Participants without adequate safeguards for self-supply outside the market and adherence to cost-causation principles will result in unjust and unreasonable costs. MISO has not presented sufficient justification, other than a highly suspect cost-benefit analysis, to support the aggressive implementation schedule. The only potential solution is to slow down and re-analyze the project as a whole.

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79 *California Independent System Operator Corp.*, 116 FERC 61,274 at P 1380.

80 In its order on California's MRTU program, the Commission stated: "We accept the CAISO's proposal for developing measurable readiness criteria through a collaborative process, identifying mitigation actions for non-performance or failure to meet readiness criteria, establishing a methodology to determine if the CAISO, Scheduling Coordinators and market participants are prepared for MRTU implementation and developing an MRTU readiness tracking system tied to specific milestones within the MRTU program timeline. *California Independent System Operator Corp.*, 116 FERC 61,274 at P 1415 (2006).

81 *California Independent System Operator Corp.*, 116 FERC 61,274 (2006) at P 1414 ("We direct the CAISO to file, at least 60 days prior to the effective date of MRTU Release 1, a statement certifying market readiness.") "We believe that it is essential that the require the CAISO to file a readiness certificate with the Commission prior to the implementation of MRTU." *Id.* at P 1380

82 *Id.* at P 1417.

### c. Schedule 17 Issue

Under Schedule 17 of the TEMT, certain parties reached a settlement with MISO and are excluded from bearing a share of allocated costs for the Day 2 Market.[83] The filed redline fails to address how these entities are to be considered for purposes of the ASM. If they participate in the ASM, they should not be excluded from bearing a proportionate share of costs.

## VIII. LIST OF ATTACHMENTS

| | |
|---|---|
| Attachment A | Affidavit of Barry J. Bentley |
| Attachment B. | Affidavit of Lin Franks |
| Attachment C. | Affidavit of John E. Haselden |
| Attachment D. | Affidavit of Michael L. Holtsclaw |
| Attachment E. | Affidavit of Dr. Ronald R. McNamara |
| Attachment F. | March 22, 2007 Presentation at EEI CEO Meeting |
| Attachment G. | MISO 2004 Annual Report |

[83] *See* section 4 regarding the settlement agreement among the MISO, Minnesota Power, and Minnkota Power Cooperative, Inc., regarding Agreement Nos. 284, 316 and 450.

## VII. CONCLUSION

WHEREFORE, IPL respectfully requests that the Commission grant this Motion to Intervene, and as explained herein, IPL asks that the Commission (1) reject the MISO's ASM proposal in its current format; require MISO to retain an independent third-party to do a true cost benefit analysis of the Day 2 Market; (3) provide conceptual guidance on a number of the issues raised by MISO's proposal as described in this protest; (4) establish a process and reasonable timetable for further development of the ASM design; and (5) permit oral argument on the issue of the move from a Day 2 to Day 3 market design.

Respectfully submitted,

William R. Derasmo

William R. Derasmo
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401 9th Street, N.W., Suite 1000
Washington, D.C. 20004

*Attorney for Indianapolis Power and Light Company*

Dated: March 30, 2007
Washington, D.C.

## CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of March, 2007, I have caused a copy of the foregoing document to be served electronically on each person listed on the Secretary's official service list for the above-referenced proceeding.

Christopher Jones

# ATTACHMENT A

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER07-550-000** |

**AFFIDAVIT OF BARRY J. BENTLEY**

**VICE PRESIDENT, FUEL AND ENERGY SUPPLY**

## I. RESPONSIBILITIES AND BACKGROUND

1. My name is Barry J. Bentley. I am Vice President, Fuel and Energy Supply with Indianapolis Power & Light Company ("IPL") located at One Monument Circle, Indianapolis, Indiana, 46204.

2. Including my Cooperative Engineering assignments while attending Purdue University, I have been employed at IPL for over 20 years. My experience includes positions of increasing responsibility in the areas of power generation, transmission and distribution, customer service, corporate venture capital, fuel supply, and energy dispatching and marketing. I began my career with IPL in 1984 as a Cooperative Engineering student while attending Purdue University. In 1988, I became a full-time employee, working as an engineer in Power Production. In 1990, I became Supervisor, Instrument Electrical at the H. T. Pritchard Generation Station. In 1992, I moved to Supervisor, Maintenance for all electrical and mechanical maintenance at the Pritchard Plant. Between 1993 and 1998, I was Supervisor and then Director, System Operation, responsible for the operation of the transmission system and

dispatching of generation assets. In 1999, I became Manager, Bulk Power, which included responsibility and oversight of the planning, engineering, operations, and maintenance for all IPL transmission and substation assets. In 2000, I was promoted to Principal in IPL's Corporate Venturing Group. In 2002, I was promoted to Director, Demand Coordination, responsible for strategic account management for IPL's top 300 retail customers. In 2003, I transitioned to the Director, Supply Coordination, responsible for energy dispatching and wholesale sales. In my current position as Vice President, I am responsible for energy dispatching, wholesale sales, and fuel procurement for IPL's generation fleet.

3. I hold a Bachelor of Science degree in Electrical Engineering from Purdue University. I have attended several management courses from the University of Michigan, the University of Indianapolis and the University of Virginia Darden School of Business. I am a former member of the East Central Area Reliability Council (ECAR) Operation and Compliance Panels.

4. My responsibilities as Vice President, Fuel and Energy Supply include retail demand forecasting, energy dispatching, wholesale sales, Midwest ISO ("MISO") market settlements and fuel procurement for IPL's generation fleet. I will be responsible for IPL's integration and implementation of the existing Day 2 market into the co-optimized MISO energy and Ancillary Services Market ("ASM"). I was actively involved with IPL's efforts to prepare for the start of Day 2. In Day 2, my responsibilities continue to include energy dispatching, wholesale sales, MISO settlements and fuel procurement for IPL's generation fleet.

5. I have provided expert testimony in numerous Indiana Utility Regulatory Commission ("IURC") proceedings. I testified on behalf of Indianapolis Power & Light Company, Northern Indiana Public Service Company, PSI Energy, Inc. and Vectren Energy Delivery of Indiana, Inc. in Cause No. 42685, involving the request to recover costs associated with taking transmission service under MISO's Open Access Transmission and Energy Markets Tariff ("TEMT"). I have also testified on behalf of Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana as the sole expert witness in the Order on Reconsideration in Cause No. 42962 involving Day Ahead and Real Time Revenue Sufficiency Guarantee credits and charges. In addition, I have provided expert testimony in numerous Fuel Adjustment Clause ("FAC") proceedings for IPL.

## II. PURPOSE

6. The purpose of my affidavit is to discuss the current operation of the existing Day 2 market, the costs and benefits of the existing market, proposed enhancements to the existing market and the concern and risks of the proposed co-optimized energy and ASM.

## III. IPL'S EXPERIENCE WITH THE DAY 2 MARKET

7. IPL looked forward to implementation of the Day 2 market. The MISO Day 2 market gives all participants open access to the transmission system and all available resources are centrally dispatched. MISO Day 2 promised a transparent and liquid energy market across the entire footprint of the Midwest ISO. Furthermore, on-going coordination between MISO and adjacent ISO systems increases grid reliability and was to make it possible to regionally

coordinate transmission expansion. IPL retail customers were to benefit from improved grid reliability and the transparency and liquidity of the energy market which brings about an even playing field for all utilities. This would allow IPL to make more economic purchases from the open market with the benefits flowing directly to its customers. Day 2 Locational Marginal Pricing ("LMPs") are calculated by MISO based on bids and offers submitted by market participants, and are provided by MISO to all market participants at the same point in time. This was to improve IPL's ability to obtain better market information more quickly than in the previous bilateral wholesale market environment. Furthermore, the identity of a specific unit outage would be better masked in Day 2, meaning that any increase in LMPs due to a forced outage would be caused by an actual shift in the supply curve, not any one party's inability to identify and access the most economic supply given a narrow window of time to locate such supply in the Day 1 bilateral marketplace.

8. IPL's Indiana statutory requirement is to provide fuel and purchased power to jurisdictional retail customers at the lowest cost reasonably possible. For low cost vertically integrated utilities, like IPL, the focus historically has been to utilize low cost base load generation to reliably serve its retail demand. Historically, IPL would purchase from the wholesale market in the event of a unit outage and/or to purchase economically when possible. In most cases, economical purchases were made in lieu of running higher cost natural gas and oil fired units. In Day 2, IPL offers its generation and bids its demand into the Day 2 market. IPL generation that clears the market is dispatched by MISO at locational marginal prices and all of IPL's retail demand pays locational marginal prices. As a result, MISO settlement statements must be separated between jurisdictional retail requirements and incremental wholesale sales and

purchases to meet the statutory requirement. IURC Orders provide the necessary requirements for allocating MISO charges and credits between retail and wholesale sales and the allocation of retail requirements between fuel and purchase power costs and non-fuel related MISO charges serving IPL retail customers.

9. The MISO Day 2 market poses additional challenges for low-cost, vertically-integrated, retail-oriented utilities like IPL. Utilities operating in retail regulated states must develop generating offer and demand strategies that satisfy the wholesale environment of the Day 2 market, while maintaining the fiduciary responsibility to serve retail customers at the lowest cost reasonably possible. Those strategies can be more complex when actual costs to serve retail customers are significantly different than wholesale replacement costs. For example, the actual cost of fuel to serve retail customers might be $13.00/MWh, but the replacement cost of fuel and other variable costs for the wholesale market might equate to an offer price of $20.00/MWh. Thus, a company like IPL must ensure retail customers maintain the $13.00/MWh fuel advantage while offering the remaining generating output into the wholesale market at $20.00. As a result of the utilization of the security constrained economic dispatch model, if all the generation was offered at a replacement cost of $20.00/MWh, existing generating output may be lowered by market conditions resulting in power purchases to serve retail load at $18.00/MWh. In this example, retail customers would receive purchased power costs of $18.00/MWh in lieu of actual fuel costs of $13.00/MWh from existing internal generation. On the flip side, one may argue that generation response may be limited when prices go below $13.00/MWh. This might occur for short periods during extremely volatile 5-minute LMPs, but operating history would suggest there are very few times when LMP pricing remains in the single digits. Under circumstances of

extreme sustained congestion, manual operator intervention can take place to provide more operating capability. The requirement to serve retail customers at the lowest cost reasonably possible, the unpredictability of the clearing prices, and real life operating considerations dictate the utilization of an offer and bid strategy that may appear counter intuitive to the pure theorist.

10. As implemented, however, the Day 2 market has not realized the anticipated benefits. As indicated in Lin Franks' affidavit, the recent ICF study showed Day 2 regional costs of $246 million and annualized benefits of only $70 million. While MISO Day 2 results have been more positive in 2006 as compared to 2005, the costs are still above what IPL would otherwise be exposed to, without an equal or offsetting benefit. By that I mean that the additional MISO-related capital expenses, operations and maintenance costs, and administrative and general expenses have not been offset by the additional efficiencies of the Day 2 market. Given that IPL represents less than 3% of the demand in the footprint; using the ICF study benefits, IPL would only have realized $2.1 million in theoretical benefits, compared to just over $7 million in theoretical costs. The actual impact on individual market participants will vary depending upon their size and generation and demand characteristics and strategies. For a low cost company like IPL, the cost/benefit ratio has had an even greater proportional impact.

## IV. IPL'S CONCERNS ABOUT THE ASM

11. Since the beginning of the Day 2 market on April 1, 2005, MISO and its market participants have been working collaboratively to make the existing market more efficient and to help drive additional costs, like excessive Revenue Sufficiency Guarantee costs, out of the Day 2 market. However, there is more that can be done and more cost savings that can be realized by

enhancing existing processes and procedures before implementing a very costly and complex ASM. From Lin Franks' affidavit, the projected cost of MISO's co-optimized ASM currently resides at $65 million in project costs, but the incremental benefits above and beyond existing and newly implemented procedures may be far less than projected by MISO staff. Because MISO is a non-profit organization, market participants that receive incremental benefits from the ASM must in turn cause a cost to others. IPL's concern is that the real incremental cost/benefit analysis of the co-optimized ASM will not be truly known until market participants begin receiving settlement statements. Unfortunately, this will be too late if the costs exceed the benefits. MISO staff has indicated the co-optimized ASM is necessary to achieve benefits that have not been achieved with the existing Day 2 market. Thus, we need the new Day 3 (an expensive and complex co-optimized ASM) to move forward and provide those necessary benefits. If this trend continues, then MISO might require a future Day 4 market to help achieve the unrealized expectations of both Day 2 and Day 3.

12. MISO staff has indicated they believe the financial concern of vertically integrated utilities is a concern of cost recovery. For IPL, I can say, that is not the primary concern. The concern is that any ancillary services market implemented should actually provide benefits to customers in excess of the costs. Simply stated -- if our customers are truly benefiting through participation in a MISO market, then passing the net benefits on to customers will not be a cost recovery concern. However, the concern is that extremely complex and expensive new programs are being proposed with potentially significant detrimental ratepayer impacts, without full consideration of ways the existing market can be improved at far less cost.

13. My recommendation is to gain additional operational knowledge and experience with the Contingency Reserve Sharing procedures and the newly implemented Adequate Ramp Capability ("ARC") procedures. For instance, market participants carry additional spinning and supplemental generation for regulation and contingency reserve requirements to meet NERC/ERO reliability requirements. MISO maintains similar generating reserves to help maintain reliability since they have limited access to market participants' collective reserve resources. The newly implemented ARC procedures provide MISO with the ability to access 50% of market participants' collective contingency generating resources for short term periods to avoid starting expensive peaking units and/or to carry additional high cost spinning resources to maintain their own reliability requirements; all of this while possibly paying make whole payments to those generator owners when the locational marginal price does not cover the offer price of those high priced resources. Fundamentally, it does not make sense for both MISO and market participants to carry redundant resources for reliability. However, an expensive and complex ASM design is not necessary to solve this fundamental, yet relatively simple, problem. In fact, the new implemented ARC procedures should provide substantial Day 2 savings by sharing contingency reserves to maintain NERC/ERO reliability requirements and to provide greater market efficiency by eliminating some of the duplication in cost.

## V. IMPACT ON IPL OF THE PROPOSED ASM

14. Currently, we have limited information with which to quantify the financial risks and impacts of the ASM on retail customers, including the potential risk of scarcity pricing. In addition, it is difficult to estimate the impacts of ASM clearing prices as compared to IPL fuel costs that traditionally were used to provide ancillary services to IPL customers. If one could buy

a financial product of some nature to hedge against the potential risk of scarcity pricing, the risk premium would likely be near the cost of the exposure at the start of the ASM market and for the first several months of the market. Thus, at a minimum, the ASM creates significant risks for traditional low-cost providers.

15. IPL takes its fiduciary responsibilities to serve its retail customers very seriously. IPL is a low-cost provider and IPL's retail customers are the beneficiaries of that low-cost position. Thus, we want to ensure that the benefits of the ASM market to IPL customers are commensurate with the costs. Given MISO's track record on achieving customer benefits commensurate with costs, I am deeply concerned with the ASM's potential to create significant consumer costs in excess of incremental benefits.

## VI. BALANCING AUTHORITY CONSOLIDATION

16. In its filing letter, MISO attempts to tie implementation of the new ASM with the consolidation of Balancing Authority Areas. MISO then represents that its proposed simultaneous co-optimization methodology is the most efficient way to optimize operating reserves for the footprint. That footprint-wide efficiency promise may be overstated, however, if 100% of the operating reserves in the footprint are not available to be deployed by MISO. While it may not be necessary for all balancing authorities to turn over the contemplated additional balancing authority functions to MISO for certain efficiencies to be realized, MISO's perception is that a critical number of those balancing authorities are necessary to consolidate. Given that there are only 23 balancing authority signatories to the BA Agreement and approximately 34 in the reliability footprint, IPL is concerned that it is once again being forced to participate in a

subsidization of others. In its April 3, 2006 informational filing on BA consolidation, even MISO questioned the benefits of consolidation as it related to reliability. The only conclusion IPL can draw about MISO's stance on the "must offer" is that MISO has chosen a methodology that is dependent upon consolidation of some BA functions.

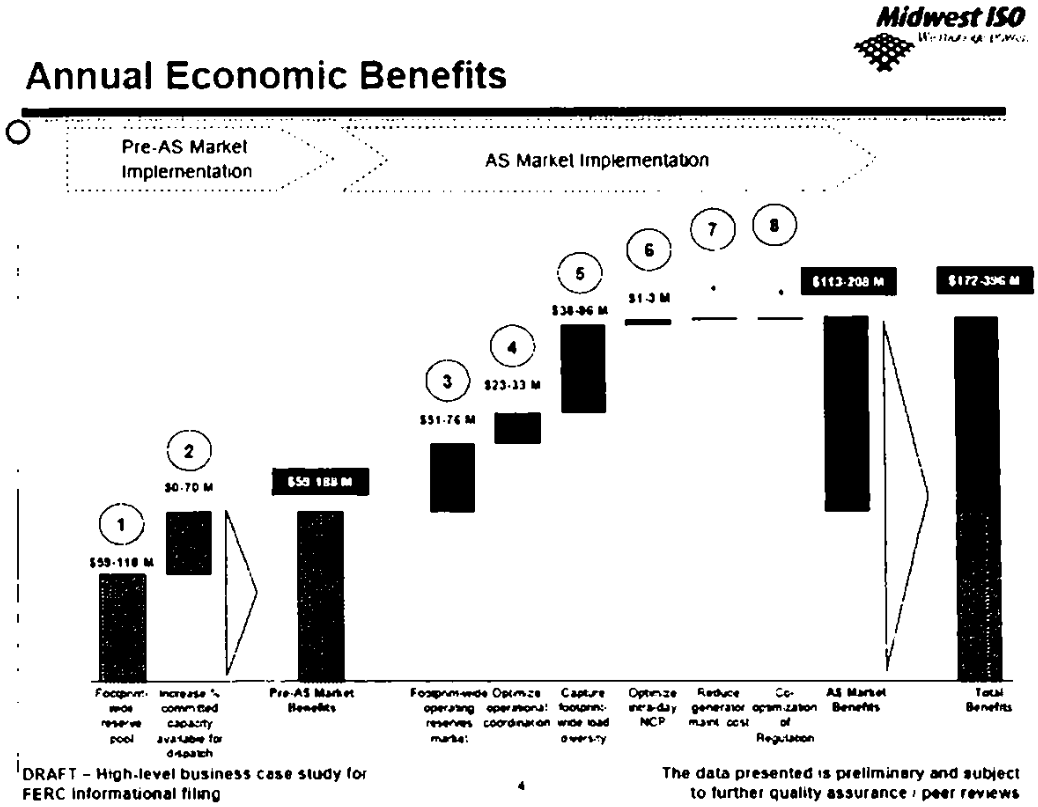
## VII. POTENTIAL IMPROVEMENTS TO THE DAY-2 MARKET, WITHOUT THE NEED FOR THE PROPOSED ASM

17. One of the improvements to the Day 2 market is the use of the newly implemented ARC procedure. The ARC procedure was designed for short-term contingencies to allow the MISO to gain additional generation ramp capability to meet load requirements and to help manage constraints with existing market participant generation reserves. Implementation of the ARC procedure will help reduce Day 2 costs by allowing the Midwest ISO operators to temporarily use up to 50% of market participant contingency reserves between the Economic Maximum dispatch level and the Emergency Maximum dispatch level without affecting reliability. As indicated in the June 5, 2006, Adequate Ramp Capability FERC filing, MISO stated:

> "The Midwest ISO has discussed the ARC procedure and the proposed tariff revisions with its stakeholders through a variety of forums, including the Markets Subcommittee. Stakeholders generally agree that prompt implementation of the ARC procedure would preserve reliability while reducing the costs to customers for RSG payments. In addition, the Midwest ISO's Independent Market Monitor supports the Midwest ISO's adoption of the ARC procedure because it provides better price signals to the Energy Markets."

18. In MISO's April 3, 2006 informational filing on BA consolidation, as illustrated in the chart below, MISO represented that $188 million worth of pre-market benefits could be realized with: (1) a footprint–wide reserve pool – the Contingency Reserves Agreement resulting

in $118 million in savings; and (2) an increase in committed capacity available for dispatch – the ARC procedure – saving an additional $70 million.




19. The Contingency Reserves Agreement went into effect as of December 31, 2006; the ARC procedure on March 20, 2007. Accordingly, these two simple pre-market solutions may actually be all that is needed. However, given their short histories, we do not know that answer. What we do know is that these options cost almost nothing to implement and carry no inherent risks. As opposed to the ASM which is expensive, complicated, carries high IT risks, increases uplift and exposes MISO members to increased financial and regulatory risks. If as anticipated the already implemented virtually no cost options do achieve the anticipated $188 million in annual benefits, no further dramatic market redesign may be necessary. If they do not achieve all

of these benefits, the experience gained will help MISO and the Market Participants better target further cost-effective improvements.

20. This concludes my affidavit.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

City of Indianapolis )
State of Indiana )

**AFFIDAVIT OF BARRY J. BENTLEY**

I, Barry J. Bentley, being duly sworn, depose and say that the statements contained in the foregoing Affidavit on behalf of Indianapolis Power & Light Company in this proceeding are true and correct to the best of my knowledge, information, and belief.

Barry J. Bentley

Subscribed and sworn before
me this 29 day of March, 2007

Carol F. Simpson
Notary Public, State of Indiana

Printed Name: CAROL F SIMPSON

My Commission Expires: July 19, 2009

# ATTACHMENT B

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER07-550-000** |

**AFFIDAVIT OF LIN FRANKS**
**SENIOR MARKET STRATEGIST**

## I. RESPONSIBILITIES AND BACKGROUND

1. My name is Lin Franks. I am employed by Indianapolis Power & Light Company located at One Monument Circle, Indianapolis, Indiana 46204. As explained in greater detail below, I served as the Chair of MISO's Ancillary Services Task Force as well as the Chair of the State Ratemaking Study Group. Thus, I offer this testimony with the unique perspective that comes from having served in those roles. I was hired in November 2004 by Indianapolis Power & Light ("IPL") to engage in the Midwest Independent Transmission Operator, Incorporated ("MISO") stakeholder process directly and to manage the interaction in the stakeholder process of a team of IPL subject matter experts. My responsibilities include, but are not limited to, facilitating the development of a point of view on issues, promotion of that point of view with MISO and other stakeholders, and development and implementation of a strategy for exercising IPL's voice on those issues with the Federal Energy Regulatory Commission. The focus of this effort is to secure an outcome that is in the best interests of IPL's customers and shareholders.

2. I have more than twenty-five years industry experience the United States and Western Europe energy industries with a focus on hub and market design and development for both the natural gas and electricity sectors. Prior to joining IPL, I held positions with a large consulting firm (Accenture) and a smaller consulting firm (Teknecon) where I served utility and other energy industry clients globally. I also have held both line and officer positions in the electricity and natural gas sectors where I contributed to the success of the two most notable natural gas hubs/market centers in the world, Henry Hub and Zeebrugge. In my global consulting positions I have assisted utility incumbents with strategies for addressing market liberalization and deregulation including enterprise risk management program development, market entry strategies, and development of strategies for new business models for emerging markets. I also initiated and led the US electricity industry effort to develop a trading culture and contract language for the over-the-counter electricity market at the California-Oregon Border. During this process I organized and led an ad hoc committee of 120 risk managers, operations engineers, and lawyers from all United States NERC regions to develop appropriate language for the then nascent trading environment for electricity. The contract language developed was later incorporated into the WSPP Tariff and became the standard on the West coast.

3. My career and experience spans the competitive evolution and liberalization of four global industries: crude oil, natural gas, electricity and telecommunications. I was a contributing author in a book published by Risk Publication, "The US Power Market" and the March 2000, "Telecommunications Revolution". I also contributed to the Energy

Publishing Enterprises 2000 publication "Energy Derivatives: Trading Emerging Markets". I served as chairman of the Energy Risk Management Association from 1994-1997 and served as Vice President from 1992-1994. I am also a member of the New York Mercantile Exchange Advisory boards for the Natural Gas Futures, California Oregon Board, Palo Verde and PM electricity futures contracts as well as a member of the Institute of Gas Technology Advisory Board. I hold a Bachelor of Science in Civil Engineering Technology from the University of Houston.

## II. IPL'S PARTICIPATION IN THE MISO STAKEHOLDER PROCESS

4. Prior to November 2004, IPL's participation in the MISO stakeholder process was limited to technical and transmission related issues. *(See Affidavit of Michael L. Holtsclaw).* IPL contributed significant expertise to those issues related to MISO's Day 1 market. Beginning in November 2004, IPL dramatically increased its resource allocation toward engaging in the MISO stakeholder process as it related to implementation of the Day 2 Energy market and the developments of methodologies for transmission expansion cost sharing. Indeed, my position is a direct reflection of how important IPL recognizes it is to make sure its position is brought before MISO. With the implementation of the Ancillary Services Task Force ("ASTF") and the initial discussions of the Day 3 or the Ancillary Services Market ("ASM"), IPL once again increased its resource allocation for the MISO stakeholder process. Although IPL is one of the smaller members of MISO, IPL does contribute resources to the MISO stakeholder process equal or greater than many of the larger MISO members.

5. Moreover, IPL has often served in positions of leadership in the stakeholder process. I personally have held the position of Chairman of the Ancillary Services Task Force for throughout its existence and also was Chairman of the Committee Restructuring Working Group for a period of time. I am now the Chairman of the ASM State Ratemaking Study Group.

6. Currently, IPL has 19 subject matter experts assigned to engage in the stakeholder processes related to their specific areas of expertise. This group meets at least once per month to share information on the activities and direction at MISO with each other and with our company leadership. For more urgent issues, the coordination is "as needed", which is often daily or continuously throughout the day.

7. IPL has expanded its focus on MISO issues as appropriate based on the experience and responsibilities of the personnel involved. The priority of our focus also changes with the developments of MISO. This is demonstrated by the chart below. As shown, IPL takes the stakeholder process extremely seriously.

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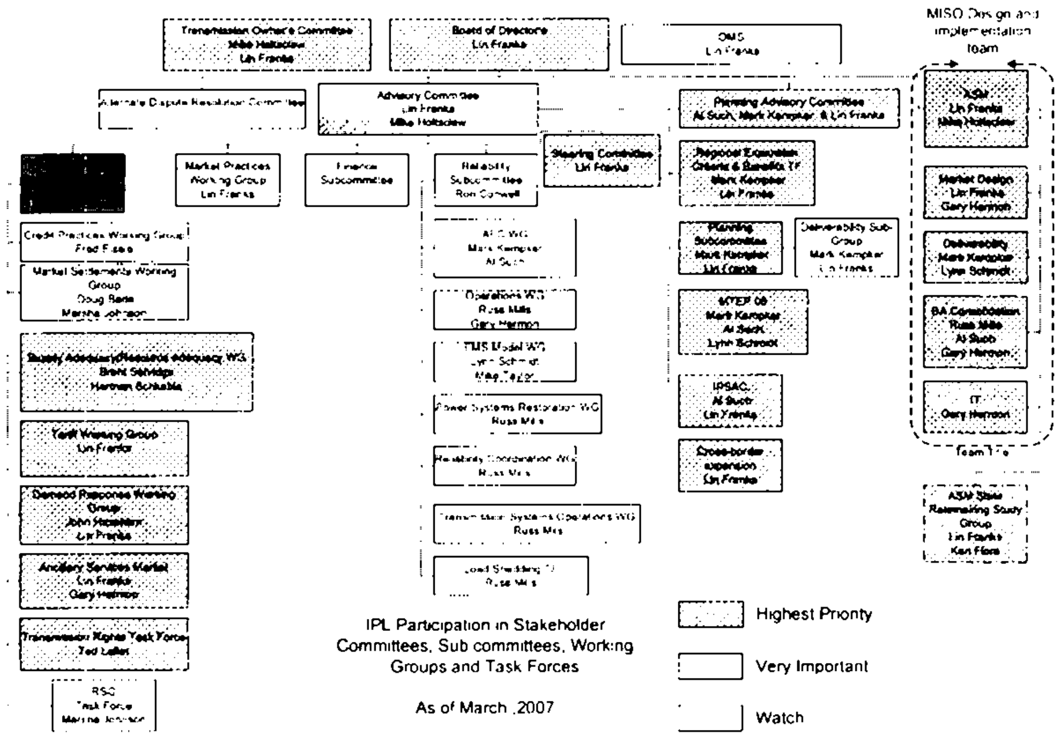



IPL Participation in Stakeholder Committees, Sub committees, Working Groups and Task Forces

As of March ,2007

8. As all of the individuals assigned to engage in the stakeholder process are resources critical to the operations of IPL, their commitment to contributing to the MISO stakeholder process places additional strains on the company and on each of them individually.

## III. IPL'S WORK ON THE ASM STAKEHOLDER PROCESS

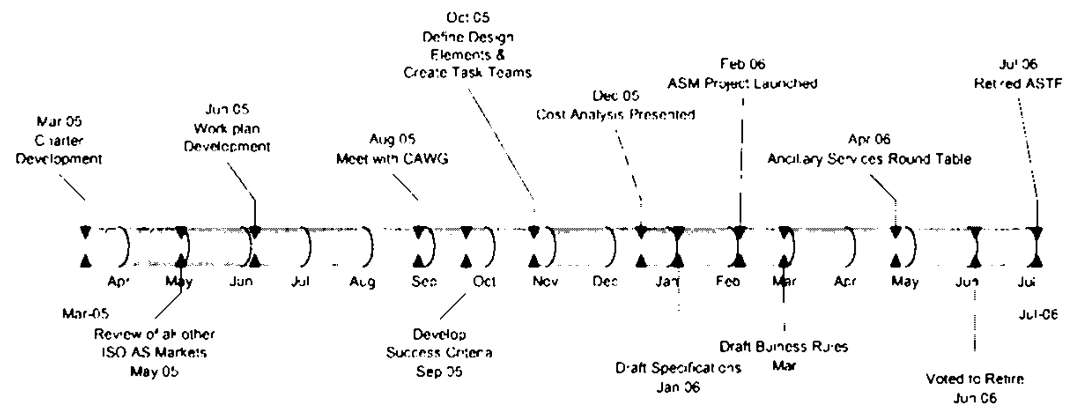
9. The initial effort to develop ancillary services markets for the MISO footprint was set in motion by the stakeholders themselves and not by MISO executives. In February 2005 the Markets Sub Committee formed the ASTF. I was selected to be the Chairman; John Harvey, then with the Iowa Commission and now with FERC, was selected as the Vice Chairman. Because the Stakeholder Governance Guidelines suggest that the role of the Chairman is to facilitate the meeting and discourages the Chairman from using the

Task Force as a forum to promote his or her company's agenda, IPL dedicated another subject matter expert, Mark Kempker, as IPL's representative in that task force. Mr. Kempker contributed significant man-hours toward the research of other Ancillary Services Markets and ultimately delivered a significant share of the ASTF's work product in this area. This group of diverse MISO stakeholders met at least once per month through the life of the task force. Participation appeared to include representatives from most if not all stakeholder sectors.

10. This stakeholder initiative did not get MISO executive support until one year after it was chartered by the Market Sub Committee. The stakeholders together with some support by MISO staff researched and analyzed the ancillary services markets in other RTOs, formulated key success criteria, initiated the development of business rules and coordinated with the reliability task force until they could make no more progress without the commitment of MISO senior staff.

11. At that time, I secured a meeting with John Bear to "circle the wagons". Also participating in that meeting were Doug Hils of Duke (the then Chairman of the Reliability Sub Committee), Peg Abbadini (the MISO Liaison for the Reliability Sub Committee) and Mike Robinson (the ASTF MISO Liaison). We requested that MISO assign an executive sponsor to take the stakeholder developed materials and proceed to the next logical level. Mr. Bear agreed and ultimately Roy Jones was selected to lead the Ancillary Services Market Project. The ASTF and the ASM ran concurrently for a short period, and then the stakeholders elected to retire the ASTF and turn the reigns over to

Mr. Jones. The chart below illustrates the timeline for the life of the ASTF and the major milestones for that stakeholder effort.




12. Toward the end of the ASTF effort, the participants were provided with a series of presentations by Michael Cadwalader, a principal with MISO's consultant, LECG. The series purported to illustrate the efficiencies to be gained by simultaneous co-optimization. The series of presentations, although said to be high level were still extremely complex concepts that were foreign to many of the ASTF participants. Prior to the development of the actual proposed MISO ASM design, Mr. Cadwalader provided several scenarios for potential outcomes of clearing prices that were at best, deeply disturbing. In one such scenario, the potential clearing price for regulation was twice the value of lost load. At $7,000 per MWh, it does not take very many hours to have a significant and negative financial impact upon a small, retail-focused entity such as IPL. At no time during these presentations was it mentioned that simultaneous co-optimization was dependent upon functional Balancing Authority Area consolidation or mandatory participation in the ASM.

13. Since the beginning of the ASM Project, there has been at least one, but usually more IPL subject matter experts at all of the ASM Project meetings including market design, IT Users Group, Balancing Authority Committee, and Project Update Meetings. It was not until approximately one month before the original schedule for filing of the ASM tariff sheets that MISO mentioned the "must offer" obligation. Until that time, naturally, IPL assumed that the success criteria developed by the ASTF on September 22, 2005 would be honored and incorporated into the design. Those criteria included several important criteria that MISO ultimately chose to either ignore or reject. These criteria were:

- The market must be voluntary both for generators and demand response;
- The design and structure should exhibit a positive benefits/cost [to load];
- The associated costs should be allocated according to cost causation principles; and,
- Sellers should be able to offer ancillary services to other RTOs.

It was also recognized by the ASTF and listed as a criterion for success that a transitional approach may be required to move from the existing procurement environment to an ASM. One reason for this transitional approach was recognition of the need to coordinate with state regulatory authorities and the time needed to prepare rate cases.

14. As a result of IPL's concerns with the state regulatory challenges with the developing design of the ASM by Roy Jones's team, IPL initiated the creation of the ASM State Rate Making Study Group with Mr. Jones's approval. This nascent group was formed to identify challenges to the ASM design as a result of state regulatory

constructs and, where possible, to develop potential solutions to those challenges. The Organization of MISO States was solicited for participation as were the regulated utilities. The OMS has been very helpful and supportive of this effort.

15. By the second meeting of this study group *on January 24, 2007,* it was determined that in seven out of 11 states in the market footprint, the current state recovery mechanisms are insufficient to address the clearing price based ancillary services and the capital and operating costs associated with the ASM. For now, those costs are trapped. There are 12 states in the market footprint and 14 in the reliability footprint. Only one state in the market footprint, Pennsylvania, has failed to weigh in on this issue.

16. Other than the LECG presentations in the ASTF, MISO has yet to provide in any stakeholder forum, an analysis of the magnitude of the clearing prices under various scenarios. Some scenarios of possible clearing prices will be those where clearing prices approach the value of lost load of $3500/MWh. Without this information, the Study Group participants have no way to determine the magnitude of financial impact to the utilities and their customers. This group has requested that such a study be undertaken and we are advised that it is underway.

17. The utilities that are regulated in one or more of the seven states have no information with which to make a business decision to move toward a rate case, nor do they have the requisite information to assess benefits and costs that accrue to their

customers. As Operating Reserves have not traditionally been under FERC jurisdiction, and for the most part are local in nature, IPL is at a loss to understand why MISO would choose to blatantly ignore this state jurisdictional challenge in its design criteria. In a recent MISO Board of Directors Committee Meeting, Graham Edwards stated that he does recognize that there are some issues with state regulation and that rate cases take some time to prepare and hear. He also stated that MISO cannot wait that long. IPL is concerned with the attitude of MISO's leadership toward state ratemaking concerns.

18. IPL recognizes and appreciates the significant efforts of Mr. Jones and his development team including but not limited to Peg Abbadini, Matt Tackett, Doug Taylor and Mike Robinson. Our concern is that they are being driven by MISO senior management, and the MISO Board of Directors, to complete this difficult and complicated project on an overly-aggressive schedule that fails to allot sufficient time to assess options that might achieve many of the benefits at less cost. This initiative has required most of them to work non stop throughout the project. IPL is concerned that the condition under which these people have been force to work to complete their tasks will introduce potentially significant risk of human error as a result of burn out. Irrespective of IPL's respect for the work that has been accomplished to date, we feel there is a great deal more work necessary on the details and modeling of potential outcomes and benefits before we can support the concept of filing *any* ancillary services market with FERC, to speak nothing of a design as complex and expensive as the particular design submitted by MISO in this docket.

19. IPL subject matter experts have sought to make their position heard by MISO. They have engaged in the stakeholder process, asking appropriate questions in the public forum as well as engaging in off-line discussions with MISO staff and other stakeholders. We listen to the information provided, ask appropriate questions, analyze the issue together with other IPL subject matter experts, and then raise the issue with MISO staff either for expression of concern or for clarification. IPL, however, is becoming concerned that our issues are being subjugated by the agendas of the large asset owners and the independent power producers. It appears that IPL and the rest of the stakeholders are considered to be just noise. MISO is no longer attempting to balance the interests of customers with independent power producers, but is allowing the interests of the independent power producers and economists enamored of theoretically elegant market solutions to increase costs for consumers, or at the very least, create unwarranted risks for consumers. This is a very unfortunate development. MISO must understand the serious impact that filings such as the ASM can have on a small utility such as IPL and needs to have a greater understanding of our cost incurrence and cost recovery concerns. Beyond just cost incurrence is the significant uncertainty hoisted upon smaller entities such as IPL. As discussed earlier, the potential for huge price spikes and loss of load values creates significant risk for customers, especially those served by low-cost providers such as IPL.

20. Prior to Day 2, FERC praised MISO for its stakeholder process. That praise is not warranted today. From the point in time that the ASM Project was initiated, the stakeholder meetings to discuss the various issues have constituted a virtual blitzkrieg. In

the course of 11 months, 40 stakeholder meetings on this topic alone were conducted. Many of these were overlapping with other critical stakeholder meetings such as discussions on the Contingency Reserves Agreement, Benefits/Cost study meeting, transmission expansion cost sharing, transmission planning, Advisory Committee meetings, Transmission Owner meetings, Market Sub Committee meetings and more. In total, in this period, IPL's staff of 19 subject matter experts was required to participate in more than 120 stakeholder meetings all while taking care to meet the requirements of their primary responsibilities in IPL operations. There is no way that such a compressed schedule has permitted thoughtful consideration of options or reasoned analysis of burdens and benefits. I must emphasize that the foregoing thoughts are offered from the perspective of an individual deeply involved in the day-to-day stakeholder process "on the ground" in Carmel, Indiana.

## IV. IPL'S CONCERNS OVER THE STATE OF DEVELOPMENT OF THE ASM

21. During the meetings to establish the ASM, one of the concepts established was that stakeholders with specific subject matter expertise would be called upon to contribute that expertise in the development meetings. The aggressive timeline of the filing left many issues largely unaddressed, with the constant refrain that details will be worked out over the development period. While that may be acceptable by those who do not pay the bills or have a responsibility to their franchised customers, that is not acceptable to IPL with a responsibility to prudently manage our customer service, particularly in light of the ICF Study results. Those results are already disappointing in

light of the gross "benefits". Richard Doying of MISO estimates the annual costs of schedules 16 and 17 at $120 - $125 million. If the annualized realized benefits of Day 2 are $70 million, then at the footprint wide level the benefits are negative even without inclusion of the other costs of MISO membership like schedule 10 and the need for increased resources to manage the processes.

22. The actions and decisions of MISO Senior Leadership and the MISO Board of Directors do not have effects limited to a pure economic model. This conceptual model must be applied to a real world scenario that includes legacy state regulation, human ability to assimilate change, and the real cost impacts to real customers. Without the details of yet-to-be-developed theoretical market design that has never been successfully implemented across a region as large as MISO there is no actual proof that the real customers will benefit. Accordingly, IPL cannot support this market model at this time and stage of development.

### 1. The Business Practice Manual (BPM) Process

23. Currently, stakeholders have very little input to the development and application of the business rules. There is no established process that requires MISO to provide their draft business rules to stakeholders prior to implementation and no established process for stakeholders to provide their input toward changes before they are implemented. In fact for the most part the details that are critical to the operations of this market are still undeveloped. This is a systemic problem at MISO and not just related to the ASM. The only BPM process in which stakeholders can have input is after the fact and only to assure that the business practice manuals and tariff conform. As a result, the Steering

Committee, a newly formed Committee reporting to the Advisory Committee has recommended that the Tariff Working Group and the Business Practice Working Group be combined. MISO should be ordered to work with this group to develop an appropriate process that provides timely distribution of the business rules, not only for this market concept but for all business rule developments, and an appropriate process for stakeholder input as well as change management. The business rules are critical to stakeholders and should be developed collaboratively with the stakeholders. No stakeholder should be asked to take a "leap of faith" that the details will work out for them. History has shown that the lack of transparency and inclusion of the stakeholders in this business rule development has actually led to conflicts between the business rules and the tariff as well as in how the software is coded. This should never be acceptable as an after- the-fact process. The detailed rules must be developed, vetted with the stakeholders and distributed prior to asking stakeholders to accept a market model and particularly if that market model is responsible for a step change as large as this proposed ASM.

**2. Uplift Costs**

24. One of the concerns that IPL has with the MISO proposed ASM design is that it has the potential to increase an already unacceptable level of uplift. As these new markets are both day-ahead and retail, any differences between will cause uplift. When this issue was raised in stakeholder forums, MISO did not dispute the potential for increased uplift. The facts causing uplift are not visible and transparent for a stakeholder. To date MISO has not provided an solution to his problem and is now adding other

factors with the potential for uplift increase that should be significant. For IPL, however, increasing uplift is unacceptable.

### 3. Must Offer

25. Competitive markets encourage participation by visible benefits to be gained from participation, such as lower or higher prices depending upon one's position in the value chain. Markets that force participation are not by any stretch of the imagination "competitive." Compulsory co-optimization may yield an overall lower cost on the 12 state footprint wide basis; but, for that to occur, those with high cost ancillary services will have to be subsidized by those with low cost ancillary services. The low cost providers will then either have to absorb the increase, or their ratepayers will have to bear higher costs. As the provision of ancillary services is part of the utility's base rate in many states, those utilities or their customers will have to pay for subsidizing companies several states away. How can FERC rule that to be just and reasonable?

26. Even if the market eventually yields measurable benefits, and a state regulated utility makes a business decision to prepare a rate case, it takes time, information, and resources to prepare and hear both on the part of the utility and on their state commission. In the interim, the financial consequences are heaped upon the utility and add to the concern that there are no material benefits to MISO membership.

### 4. The Lack of Ability to Self-Provide

27. While MISO's market design provides for the ability to self schedule, that is not equal to self-provision. When one self-schedules one is a price taker and is subject to congestion and losses. In contrast, self provision provides the state regulated utility with the ability to continue to reliably serve its customers by in effect "opting out" of the ancillary services market for a specified period of time. State regulated utilities must not be forced to participate in the ancillary services co-optimization, which in fact may require state approval to participate.

### 5. Balancing Area Consolidation

28. MISO erred in combining BA consolidation, a reliability issue, with a market condition. These two issues should be kept separate in the interest of a competitive environment for electricity. While in a mature market it is possible for the market itself to contribute to reliability, MISO's Day 2 market is still far from mature. Any ASM market design implemented would need time to mature before it could material contribute to reliability. Forcing the participants with designated network resources to offer their operating reserves into the market does not equal increased reliability. It does however, put them at a disadvantage, as the opportunistic IPPs in the marketplace are free to make a business decision to participate or not. Additionally a market in which companies are forced to participate will not develop in a manner that permits visible and measurable benefits that will both become compelling for participation on its own merits. Visible

and measurable benefits are the key to surmounting the challenges of legacy state regulatory structures and recovery methodologies.

### 6. Value of Lost Load – Scarcity Price

29. IPL is concerned that the use of the value of lost load demand curve exposes ratepayers in the MISO footprint to scarcity prices above those born by customers in other RTOs. Given the lack of requisite detail of the proposed market design it is unclear as to when prices for operating reserves products will approach the Value of Lost Load ("VOLL") and for how long prices will be sustained at that high level. Other than the LECG presentations provided to the ASTF, there have been no studies presented to stakeholders to indicate the potential impacts of the VOLL. IPL has historically been one of the lowest cost retail providers in the United States. The implementation of scarcity pricing together with a "must offer" feature could cause significant financial harm. In my expert opinion, based on my years of industry market and fundamental experience, I believe this is a recipe for catastrophe. How, then, can FERC support this as just and reasonable?

### 7. Dynamic Reserve Zones

30. As designed and filed with FERC on February 15, 2007, MISO proposes that it be permitted to change the scope of the reserve zones as frequently as daily. This frequency is not only impractical but it makes both physical and financial hedging of the operating reserves and their clearing prices virtually impossible. As of the filing date, stakeholders had no understanding of their access to the necessary data for shadowing. Subsequent to

the filing, MISO represented that they too find the frequency to be impractical and stated that stakeholders will have access to the request data for shadowing. Stakeholder concerns were stated on this issue prior to MISO's filing of the tariff sheets, but were not addressed. Again, stakeholders have still not been given enough detail to understand the impact of having to download significant incremental amounts of data perhaps multiple times per day.

31. Additionally, given that the MISO footprint "reserve pockets" are static for much of the footprint, this design element does not make sense. It could potentially create locational market power problems as well.

### 8. Projected Benefits of the ASM

32. Given MISO's history of gross over-estimation of benefits and under-estimation of costs, IPL cannot take that "leap of faith" we are asked to take with this conceptual design. The implementation costs are significant and customers will be significantly impacted. In their 2004 Annual Report, MISO promised $713 million dollars of benefits footprint-wide from operation of the Day 2 market. According to the recently published ICF cost/benefits study, only $70 million annualized of a potential $552 million has been realized to date. The 2004 Day 2 business plan estimated implementation costs of $191.9 million; however the ICF study states that $246.7 million have been spent to date. Given these variances, how can stakeholders believe the benefits vs. costs estimates provided by MISO for Day 3? If we assume the variance in estimated-to-realized Day 2 benefits vs.

costs is a pattern, then the benefits vs. costs of Day 3 is more realistically estimated to be $84 million costs vs. $20 millions in benefits.

33. The simultaneous co-optimized ancillary services market is touted as the panacea for all that is wrong by both MISO senior executives and the Independent Market Monitor. The conceptual design and the expectation of benefits ignores the state regulatory challenges and assumes that all market participants, regardless of business model and regulatory framework, have the same opportunities and motivation for participation. These are false assumptions.

34. For the most part, vertically integrated utilities take their responsibilities to their customers (ratepayers) very seriously. They have a long history of assisting each other during contingencies; and are not motivated to game the system by withholding. The rules for this conceptual market were developed to mitigate the fear of a shortage in operating reserves and a fear of potential withholding. While potentially appropriate for those with only a profit motive, they are not appropriate for a membership comprised largely of vertically integrated utilities. These vertically integrated utilities are far more motivated to protect their customers than to "push the envelope" with respect to the rules. These rules (the must offer, the additional dispatch bands, and others) will potentially add costs, but will add few if any benefits to those utility customers.

35. The benefits vs. costs analysis that MISO is using to explain why they should move forward with the Ancillary Services Market Design is the one they filed on April 3,

2006 to explain the benefits of Balancing Authority Area consolidation. That "study" was conducted exclusively by MISO staff and without the benefit of even a conceptual design for that market. Additionally, there was no consideration in that "study" for the costs that actually impact member utilities and their customers. Even today MISO is still using that "benefits" study without any updates for the impact of their proposed ASM design.

36. There is a difference between a financial cost benefits analysis (CBA) and an economic cost benefits analysis. A financial CBA is made from the perspective of a person, group or unit directly involved in the project. In this case that unit is a state regulated utility that is a member of MISO. Expenses or costs born by that utility and benefits that would actually accrue to that utility and its customers are taken into account. An economic CBA takes the broader perspective of society such as the MISO footprint. It is appropriate to include all costs including those borne by third parties. Typically when calculating the benefits, it is not the market price of a cost or benefit that is used but the so called real price that is representative of its value to society. It is often the case that the financial analysis turns out to be unprofitable, while the economic analysis looks to provide benefits in excess of its costs.

37. While the CBA provided by MISO is nowhere near as granular as to include all the costs borne by the society in the footprint, conceptually it is scoped to be an economic analysis. While some may say that this type of analysis is probably the only type appropriate for MISO to perform, it has little value to those who serve load who have

been promised they will see substantial benefits at reduced costs. It is imperative that information needed by utilities and their state regulators to perform the financial analysis is provided by MISO to those entities. It is also imperative that the financial impacts to the utilities and their customers not be ignored when considering development and implementation of a project. Additionally, both the April 3rd representation of costs vs. benefits and the ICF study fail to provide the timeline for realization of those benefits.

## V. IPL Letter and the Response

38. IPL delivered a letter to Chairman Kelliher on February 14, 2007 (the IPL Letter) detailing the concerns with the Ancillary Services Market Design and Implementation schedule. On March 2, 2007, a group of Independent Power Producers delivered a letter in response to the IPL Letter. IPL applauds stakeholders who stand up and exercise their voice and points of view on developments and issues as important as the proposed MISO ASM. We are however concerned when the voice exercised either deliberately or inadvertently misrepresents another stakeholder or group of stakeholders' message to FERC. Contrary to the story told by Calpine Energy Services (IPP), Dynegy Power Marketing (IPP), FirstEnergy Solutions (Power Marketer), Reliant Energy (IPP) and Williams Power Company, Inc. (Power Marketer) in their March 2, 2007 "Response" Letter, no party who was a signatory to the IPL Letter is opposed to an appropriately designed and developed ancillary services market.

39. It appears that these parties did not verify the information they so loosely referred to as "facts" in their response letter starting with their very first sentence when they made

the claim that the IPL Letter was submitted by seven Midwest Independent Transmission System Owners. The IPL Letter was submitted by IPL, Southern Illinois Power Cooperative, and Hoosier Energy, all of whom are registered with MISO as vertically integrated transmission owners. Additionally, the letter was signed by WPS Resources who is registered in the MUNI/COOP/TDU sector, Coalition of Midwest Transmission Customers and Midwest Industrial Customers representing the End User Sector, and the Electricity Consumers Resource Council representing large industrial customers. The only thing the Responders got right is that there were seven names listed on the letter. Those seven names however represent far more than seven entities and a far more diverse group of interests than those of the responders. And more importantly, the entities who signed the IPL Letter represent the members who will shoulder the costs associated with the ancillary services market either directly or indirectly. The responders are merely the opportunists who stand to profit from the existence of the market. As factually presented in the IPL Letter and not completely disclosed in the responders' letter, MISO did make changes to the market design subsequent to the vote of the Advisory Committee, however those change were concessions to the IPP and Power Marketer sectors, and did not address the concerns of the entities who signed onto the IPL Letter. The following table addresses the list of statements offered by the Responders in their misrepresentation of the IPL Letter.

| *Responder's Statement* | IPL Answer |
|---|---|
| *1. While the IPL Letter labels the MISO Proposal as "premature," formal discussions and meetings have taken place with MISO stakeholders and staff for at least 18 months.* | See paragraphs 4-14 above. |
| *2. The IPL Letter describes the MISO* | As chair of the ASM State Rate Making |

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| *filing as "insufficiently detailed", but the MISO Proposal had not been filed with the Commission when the IPL Letter was submitted on February 14th, so the IPL entities made this assertion before seeing the final filing. Given that the MISO proposal was 2,139 pages, with significant details on all aspects of the Proposal, we believe IPL's characterization of the filing prior to the filing even being made is incorrect.* | Study Group and on behalf of IPL, I personally read and analyzed every draft of the tariff sheets provided by MISO to Stakeholders prior to the filing on February. 15th. IPL and the ASM State Rate Making Study Group submitted comments to MISO on the draft tariff sheets by their stated deadline of January 26th. Stakeholders were not permitted to see the final tariff sheets before filing. However, given the tight timeframe and IPL's deep involvement in the entire process from the absolute beginning of the ASM effort, I am qualified to say that the assertion of the Responders is misguided. Further, just because there are 2,139 pages in this filing does not mean that there is sufficient detail to the business rules, settlements issues, modeling of clearing prices, or risk mitigation plans for an entity paying the bills to assess benefits vs. costs or to understand the operational and infrastructural impacts. The number of pages is an inappropriate measure of the detail of the documentation. |
| *3. The IPL Letter also describes the MISO Proposal as "opposed in its current from by a majority of MISO Stakeholders. As discussed above, MISO staff has incorporated several changes in the Proposal since January 2007 Advisory Committee vote. By the very nature of market design and the individualism of each corporate entity engaged in the MISO market, each entity will have numerous elements of a filing it believes should be revised to improve the overall market efficiency. While it is unlikely that any stakeholder supports the MISO Proposal in its entirety, it is a good starting point.* | For those entities that ultimately pay for the market design, development, and operation, a "good starting point" is not enough. As the sectors represented by the Responders do not have the burden of the costs associated perhaps they are content with a "good starting point". However, as a FERC Order on this proposal has the potential for extremely costly and long reaching unintended consequences, IPL maintains that taking the time to work out the details and mitigate the risks associated is not only warranted, but the only prudent action to take. We support an appropriately designed and developed ancillary services market…but not just a "good starting point". |
| *4. The IPL Letter alleges MISO is guilty of abandonment of cost causation principles in favor of socialization of all ASM costs* | This statement by the Responders does not comport with any of the 2,139 pages of the tariff filing. It also makes one wonder |

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| *on a pro rata load share ratio basis. It is misleading to assert cost causation was ever abandoned when in fact the MISO proposal is consistent with the approach approved by the Commission for other eastern United States RTOs operating Ancillary Services Market, including PJM, ISO NE, and NY ISO.* | if the Responders attended the stakeholder meetings when this issue was discussed. The costs of contingencies are allocated, not to those who caused the contingency, but to all participants across the footprint. In the tariff sheets we were allowed to see before the filing that allocation was on a load share ratio basis. The sheets as filed allocate the costs in parts of the tariff on a "pro rata" basis and on other parts on a Market Load Ratio Share defined as "The factor calculated as the Actual Energy Withdrawals plus Export Schedules of a Market Participant at all Commercial Pricing Nodes divided by the sum of all the Actual Energy Withdrawals plus Export Schedules at all the Commercial Pricing Nodes in the Transmission Provider Region." Mr. Jones maintains that because the Generator that caused the contingency is required to buy back from the market (at some point), then the tariff has conformed to cost causation principles.<br>First, the LMPs at all nodes are not equal and may ultimately be more disparate during contingencies issues. LMP are also volatile. If the generator is not required to replace dollar for dollar, then the potential exists for an extremely large percentage of the funds to be short. |
| *5. The IPL Letter accuses MISO of an aggressive implementation schedule without justification. Sixteen months from the date of filing to the market start hardly seems aggressive (June 2008 proposed market start) Furthermore, the IPL Letter fails to note the reasons why a Spring 2008 implementation makes sense, including: the anticipated cost savings to consumers resulting from a centralized and efficient market, as well as the need to provide stakeholders a timeline in which they can make investments and business decisions to help increase participation in the new market.* | The effort that MISO is undergoing in the ASM Project is essentially a re-write of many aspects of the Day 2 market while adding complicated new elements for the simultaneous co-optimization. The Responders seem to believe that this is merely shrink-wrapped plug and play software. The Responders have been told by MISO during stakeholder meetings that this project is a difficult and complicated project and that they cannot just take the software used by other RTOs and plop it down in MISO. If they could, then a 16 month customization project might make sense.<br>IPL is hopeful that an efficient market |

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| | will be the result of this effort, however, given our concern for our customers and the MISO history, we cannot make the leap to believing the promised benefits. In fact, for the benefits to the footprint to be achieved, low cost providers such as IPL will be subsidizing the high cost providers. That we cannot accept.<br>Timelines are nice things to have. We all desire certainty, including regulatory certainty. However, racing toward a timeline without development of appropriate and detailed business rules and without sufficient mitigation of the inherent risks is simply imprudent. |
| *6. The IPL Letter describes the MISO Proposal as one of extreme complexity of the design. However, most of the Proposal consists of components from other existing ancillary services markets. While parties will surely file comments with the Commission explaining why they believe certain parameters and details should be corrected in the MISO Proposal, the general framework is derived from other existing and Commission-approved markets* | The Proposal is a concept only and does derive some of the elements from other RTO AS markets, but this is not shrink-wrapped software. The vendor has never coded this type of simultaneous co-optimization before, nor has it been implemented anywhere in geography at large as the MISO footprint.<br>As represented by Roy Jones in the March MISO BOD, the vendor as now lost key resources and can no longer meet its deadlines on development. MISO has formulated a "belt and suspenders" mitigation plan to supplement the vendor's available resources by pulling them off of other MISO projects, and adding consultants. Some of the MISO staff also must be diverted from other projects.<br>The Responders have never had the responsibility of developing a project such as this; therefore they are in no position to judge its complexity. Even the MISO BOD in their March meeting recognized that the design is complex. |

40. This concludes my affidavit.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

City of Indianapolis )
State of Indiana )

**AFFIDAVIT OF LIN FRANKS**

I, Lin Franks, being duly sworn, depose and say that the statements contained in the foregoing Affidavit on behalf of Indianapolis Power & Light Company in this proceeding are true and correct to the best of my knowledge, information, and belief.

Lin Franks
Lin Franks

Subscribed and sworn before
me this 29 day of March, 2007

Carol F. Simpson
Notary Public, State of Indiana

Printed Name: CAROL F. SIMPSON

My Commission Expires: July 19, 2009

# ATTACHMENT C

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| Midwest Independent Transmission System Operator, Inc. | ) ) | Docket No. ER07-550-000 |

**AFFIDAVIT OF JOHN E. HASELDEN**

**PRINCIPAL ENGINEER, REGULATORY AFFAIRS**

1. My name is John E. Haselden. I am employed by Indianapolis Power & Light Company ("IPL"), whose business address is One Monument Circle, Indianapolis, Indiana 46204.

## I. PERSONAL AND PROFESSIONAL BACKGROUND

2. I am a Principal Engineer in the Regulatory Affairs Department. I have worked in this area since rejoining IPL in May 2006. I graduated from Purdue University with a Bachelor of Science in Civil Engineering. I also graduated from Indiana University with a Master of Business Administration. I am a registered Professional Engineer in the State of Indiana.

3. I began my employment with IPL on April 12, 1982, and worked as a Design Project Engineer in the Mechanical-Civil Design Engineering Department. I was responsible for a wide variety of projects from budget and estimate preparation through the preparation of drawings and specifications, bidding, and construction supervision. Specific projects included the design of new buildings, roads, plant water supply, cooling tower rebuilding, repairs and

modifications to existing structures, and extensive experience with protective coatings and alloy materials used in SO2 scrubber systems.

4. In 1987, I became a Senior Engineer in the Power Production Planning Department. I was responsible for assisting or conducting studies concerning future generation resources, economic evaluations, and other studies. In 1989, I was promoted to Division Supervisor of Fuel Supply and in 1990, became Director, Fuel Supply. I was responsible for the procurement of the various fuels used at the generating stations. My responsibilities included: negotiating coal, gas, trucking and railroad contracts; administering contracts; managing inventory; assuring fuel quality and planning fuel.

5. In 1993, I became Director, Demand-Side Management. I was responsible for the development, research, implementation, monitoring and evaluation of all marketing and Demand Side Management ("DSM") programs. In particular, I was responsible for the start-up and implementation of the DSM programs approved by the Indiana Utility Regulatory Commission in its Order in Cause No. 39672 dated September 8, 1993.

6. From 1997 until May 2006, I held the positions of Director of Marketing and Director of Industrial Development and Engineering Services at The Indiana Rail Road Company. I was responsible for the negotiation of coal transportation contracts with various electric utilities, supervision of the Maintenance-of-Way and Communications and Signals Departments, and engineering and development of capital projects which included new sidings, industrial tracks, bridges, and rehabilitation of tracks for the railroad.

## II. RESPONSIBILITIES AT IPL AS THEY RELATE TO THE MISO'S PROPOSED ANCILLARY SERVICES MARKET

7. I am responsible for the evaluation and economic analysis of the proposed demand response market, its implementation and impacts on IPL's customers and existing demand response programs. I participate in the MISO Demand Response Working Group.

## III. PURPOSE OF AFFIDAVIT

8. The purpose of my affidavit is to discuss IPL's concerns with the proposed business rules for demand response which include: (a) the impact of the proposed rules on IPL's existing demand response programs; (b) the timeline for implementation of the proposed rules; (c) the regulatory treatment of the costs and structure of the proposed rules; (d) technical requirements of the proposed rules; and (e) other business concerns.

## IV. IMPACT OF THE PROPOSED BUSINESS RULES FOR DEMAND RESPONSE ON IPL'S EXISTING DEMAND RESPONSE PROGRAMS

9. IPL has ten rates and riders whose participants can be considered as demand response assets. These rates and riders were designed to be responsive to system reliability events. The rates and riders are generally structured such that a customer receives a payment or different rate in return for performing a demand response function such as curtailing load or self-generating. With the exception of Rider 18, Curtailment Energy II, they are not conducive to participation in an economics-based demand response market. On the load curtailment side, there are contractual limits on duration, how many times the customers can be called upon to reduce load and minimum notice. Compensation is fixed. Consequently, customers are seldom

called upon to disrupt their business processes. The ability to call on this resource more frequently so as to participate in a market would not be acceptable to some participants and would also require much more compensation to the participant if their primary business processes were more frequently disrupted. On the self-generating side, this capacity is in the form of diesel-powered back-up generators. Customers that can perform this type of response also have contractual limits on duration, how many times the customers can be called upon to reduce load and minimum notice. Compensation is fixed and, customers are seldom called upon to generate except in emergencies. These generators provide back-up power to vital processes such as hospitals, data processing facilities and other commercial processes that cannot be interrupted or economically curtailed. These generators are also constrained by the number of hours their environmental air permits will allow them to run. Because they are generally permitted for infrequent emergency use, more frequent operation, such as operation resulting from participating in the proposed market, would likely require investments in emissions reduction equipment.

10. In the event a demand response market were established as proposed, participation in the existing programs may decline due to the potential confusion or overlapping nature of the existing IPL supported demand response initiatives and the MISO program. Those customers who develop the ability to participate in a demand response market will likely leave the existing programs for riskier but purportedly higher compensation in from the proposed market. Loss of participation in existing programs will have a negative effect on IPL's remaining customers through increased costs due to the need to purchase additional reserves. If loads are not participating in demand response programs in accordance with the state-approved programs, IPL

must consider these loads as firm loads. In this case, IPL is required to acquire sufficient capacity and reserves to serve them because there will no longer be an *obligation* for the customer to perform the demand response function when requested by IPL.

11. In the IPL service territory, the only demand response asset that could feasibly participate in the proposed demand response market would be the aggregated residential air conditioning load management (ACLM) switches. If other customers desire to participate, the physical infrastructure of metering, telemetry, and communication would need to be implemented. On the state level, the business rules and a regulatory framework acceptable to all parties would also need to be negotiated and approved. It can be expected to take a significant period of time to complete the negotiations and the necessary regulatory process, possibly more than a year. Implementation costs are not known at this time.

12. The regulatory treatment by state regulators is unknown because there is no system for which to make rules around. However, there is an *ad hoc* group of state regulators participating in a process called the Midwest Demand Response Initiative. This group was only recently formed and does not yet have a work product to evaluate. It is important to emphasize that the existing demand response programs represent a carefully constructed balance between customer capabilities and commitments and their corresponding retail rate treatments.

13. It appears that MISO has taken the approach of treating demand response assets like generating assets that have the technical capabilities and responsiveness of modern generating assets. With very few exceptions, the existing demand response assets do not have these capabilities because they were not intended to function in a market. Other than for the convenience of fitting into the MISO ASM model, it should be debated whether demand

response assets actually need the specified technical capabilities in order to function in the proposed market. Other ISOs such as PJM and ISO New England have much less restrictive requirements. In starting a new market, imposition of these costs and unnecessary complexities will prove to be a significant barrier to participation and will retard the development of the demand response market. Much of the low-hanging demand response fruit will go unpicked.

14. While the concept of demand response has been proven to be beneficial in reducing electric generation costs in traditional regulated structures, it may not be as effective in a market setting as proposed by MISO for the reasons previously stated. MISO has the cart before the horse when it comes to demand response. The critical work of framing the rules and structure between the participant, the load serving entity and the market operator must be crafted first rather than the top down approach taken by MISO of creating a theoretical market in which few can reasonably participate.

15. This concludes my affidavit.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

)
City of Indianapolis )
State of Indiana )
)

**AFFIDAVIT OF JOHN E. HASELDEN**

I, John E. Haselden, being duly sworn, depose and say that the statements contained in the foregoing Affidavit on behalf of Indianapolis Power & Light Company in this proceeding are true and correct to the best of my knowledge, information, and belief.

John E. Haselden
John E. Haselden

Subscribed and sworn before
me this 29 day of March, 2007

Carol F. Simpson
Notary Public, State of Indiana

Printed Name: CAROL F. SIMPSON

My Commission Expires: July 19, 2009

# ATTACHMENT D

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) ) | **Docket No. ER07-550-000** |

**AFFIDAVIT OF MICHAEL L. HOLTSCLAW**

**DIRECTOR, POWER DELIVERY OPERATIONS**

1. My name is Michael L. Holtsclaw. I am employed by Indianapolis Power & Light Company ("IPL"), whose business address is One Monument Circle, Indianapolis, Indiana 46204.

2. I am the Director of Power Delivery Operations. I am responsible for the operation of IPL's transmission and distribution systems. I also have responsibility for overseeing IPL's short term and long term transmission and distribution system planning.

3. I have been employed by IPL for 27 years. I began my career with IPL as an engineer in the Electric System Planning department and moved to positions of increasing responsibility to the position I currently hold as the Director of Power Delivery Operations. I have eight years of experience in Distribution and Transmission system planning, ten years of experience as a Supervisor in underground engineering, two years of experience as Superintendent of Electrical, three years of experience as Team Leader of Transmission Operations, and three years of experience in my current position as Director of Power Delivery Operations. I am a graduate of

Purdue University with a Bachelor of Science degree in Electrical Engineering Technology. I am a registered Professional Engineer in the State of Indiana.

4. I am the IPL representative to the MISO Transmission Owners Committee. I have represented IPL on the Transmission Owners Committee since 2001. I am also the IPL representative to the Balancing Authority Committee ("BAC"). The BAC has responsibility for approving any changes to the Balancing Authority Agreement between the MISO and the signatories to the Balancing Authority Agreement. Within my IPL functional area and organization, I have responsibility for overseeing the IPL Balancing Authority ("BA") functions, implementing the technical modifications to the IPL Energy Control System that will be required for implementation of the MISO Ancillary Services Market ("ASM"), and overseeing and assuring compliance with the NERC reliability standards.

5. The purpose of my affidavit is to discuss the consolidation of BA functions to the MISO as they relate to the proposed ASM and to provide information on the reasons the Balancing Authority Agreement has not yet been executed in its edited form.

6. There are currently 23 signatories to the Balancing Authority Agreement with the MISO. I believe there are reliability benefits that can be achieved by reducing the number of BAs within the MISO footprint. The MISO has proven its ability to reliably oversee Day 1 functions within the footprint. This provides a level of confidence that MISO can effectively perform the additional BA functions that would be delegated to it under the revised Balancing Authority Agreement. The consolidation of certain BA functions should result in improved efficiencies, and reduction in costs for Contingency and Operating reserves would be allocated more

economically across the footprint rather then being carried on generators with each individual balancing authority.

7. In order for the MISO ASM to operate optimally, I do believe it is necessary to transfer responsibility for certain BA functions to MISO. While BA functional consolidation might be necessary for optimal operations under the ASM design, BA functional consolidation and the anticipated reliability benefits are not dependent upon implementation of the proposed MISO ASM. It might not be necessary to move as many BA functions to MISO, if MISO implemented BA consolidation, without the ASM.

8. As proposed, IPL does not have significant concerns with the proposed BA functional consolidation from a reliability perspective. There are 388 specific requirements that a BA must comply with as defined in the current NERC reliability standards. As currently proposed, MISO as the BA would have 137 requirements with which only they would have to comply; the existing BA's would have seven with which only they would have to comply; the remaining 244 requirements are ones with which both MISO and the existing BA's would be required to comply. From a NERC compliance standpoint, the proposed functional consolidation would reduce by approximately 35 percent the number of requirements with which the existing BA would have to comply. While there may be some minor cost savings for the existing BA's, it will not likely result in any personnel reductions. IPL will still have to comply with the majority of the NERC requirements and will still have to perform some oversight functions of MISO to assure that the IPL system is being operated in a reliable manner.

9. IPL estimates that it will spend $1,026,000 to modify its system to accommodate IPL's participation in the ASM as currently proposed. Most of the costs involve software systems that either must be replaced because they cannot be modified to support the ASM, or new interfaces that must be installed to communicate with the MISO systems. There will be some new hardware required to implement the ASM on the IPL systems. MISO has indicated that it will reimburse companies for the costs to implement the ASM. IPL plans to submit all of its costs for reimbursement. The costs of the MISO reimbursement program will be spread across the market participants as part of the administrative costs to operate the ASM. IPL is concerned that MISO appears to be requiring participants to execute certain agreements such as signing the revised Balancing Authority Agreement in order to be eligible for cost recovery, prior to Commission action on the ASM. The Transmission Owners are in general agreement with the proposed changes to modify the Balancing Authority Agreement to transfer additional BA functions to MISO.

10. But because these changes have been so tightly tied to the start of the ASM, the group has expressed concerns and to date has not taken a vote to approve the modifications to the Balancing Authority Agreement. A 75 percent affirmative vote is required to approve any changes to the Balancing Authority Agreement. Contrary to MISO's representation to the Commission in its Addendum to the Filing of the Midwest Independent Transmission System Operator, Inc. Electric Tariff Filing To Reflect Ancillary Services Markets; Docket No. ER07-550-000, the issues are not limited to concerns with specific operating protocols. Issues that remain to be resolved in order to achieve a positive vote on modifying the Balancing Authority Agreement include details on the operating protocols, issues with the current ASM design,

particularly the must offer requirements, a better understanding of the costs and benefits of the ASM, and some signatories have indicated there may be regulatory issues with their state commission needing to approve the additional functional consolidations. The BAC has indicated that it will not take final action on the proposed modifications to the Balancing Authority Agreement until after the final order on the ASM is issued.

11. This concludes my affidavit.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

City of Indianapolis )
State of Indiana )

**AFFIDAVIT OF MICHAEL L. HOLTSCLAW**

I, Michael L Holtsclaw, being duly sworn, depose and say that the statements contained in the foregoing Affidavit on behalf of Indianapolis Power & Light Company in this proceeding are true and correct to the best of my knowledge, information, and belief.

Michael L Holtsclaw
Michael L Holtsclaw

Subscribed and sworn before
me this 29 day of March, 2007

Terri L. Simpson
Notary Public, State of Indiana

Printed Name: Terri L. Simpson

My Commission Expires: 8/24/08

# ATTACHMENT E

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **Midwest Independent Transmission System Operator, Inc.** | ) <br> ) | **Docket No. ER07-550-000** |

## AFFIDAVIT OF DR. RONALD R. MCNAMARA

### I BACKGROUND

1. My name is Ronald R. McNamara. I work at 9989 Erin Woods Drive, Dublin, Ohio 43017. I am an independent economic consultant. I have been retained by Troutman Sanders LLP to provide testimony in support of the Intervention and Protest by Indianapolis Power and Light ("IPL") in response to the Ancillary Service Market filing by the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). It is my understanding that IPL is supportive of electricity markets, the Midwest ISO and the concept of ancillary service markets. Moreover, the purpose of their protest is no way meant to be a criticism of the Midwest ISO but rather a statement of their concerns regarding the specific ancillary service market proposal. Similarly my comments reflect the fact that I am supportive of electricity markets, the Midwest ISO and the concept of establishing ancillary service markets in the Midwest.

2. I graduated from the University of California, Irvine with a B.A. degree in Economics and a B.A. degree in Social Ecology in 1979. I received an M.A. degree in Economics from the University of Rhode Island in 1983. I received an M.A. degree and

a Ph.D. in Economics from the University of California, Davis in 1991 and 1993, respectively. I have been involved in the energy industry for approximately 20 years in the public and private sectors, as well as performing academic research on energy markets. From 1995 to 1998, as the Manager of Research and Development for the Electricity Market Company, Ltd, and as a Senior Advisor for Putnam, Hayes and Bartlett Asia-Pacific, I was involved in designing and implementing the electricity market in New Zealand. From February 2003 until late 2006 I was an Officer of the Midwest ISO. In addition to other duties, I was the Officer responsible for the Transmission and Energy Markets Tariff and Market Design ("Day 2 Market").

3. I have also worked for the Queensland, Australia state regulatory commission, Duke Energy (Australia), Enron and American Electric Power as well as having taught at universities in Australia, New Zealand and the United States.

## II. PURPOSE OF THE AFFIDAVIT

4. I have been asked to provide both general and specific comments on the filing made by the Midwest ISO on February 15, 2007 in Docket No. ER07-550-000 to replace the current Day 2 Market design, which is primarily an "energy-only" market, to put in place a new market design based on the co-optimization of energy and ancillary services.

## III. SUMMARY OF AFFIDAVIT

5. The filing made by the Midwest ISO on February 15, 2007 represents an extraordinary amount of work performed by the Market Participants and Midwest ISO staff in a very short period of time. In simple terms the filing seeks permission to enhance the energy markets allowed under the current Transmission and Energy Market Tariff by centralizing certain activities presently performed by the Balancing Authorities in regard to ancillary services. An explicit and necessary outcome of this proposal, if accepted, will be to increase the scope of activities performed by the Midwest ISO. This is an extremely important filing and its sheer volume is an indicator of just how substantial a reform this would be to the existing markets currently operated by the Midwest ISO -- markets that have been in operation less than two years. The sole rationale provided for changing the existing market design is to gain the potential *economic* benefits arising from the "functional consolidation of Balancing Authority responsibilities and the centralized commitment and dispatch of energy and Operating Reserves and Regulation."[1] The Midwest ISO provided a range for these economic benefits net of ongoing costs of between $82 and $177 million.[2] These are the estimated *theoretical* benefits of implementing ancillary service markets in the Midwest. In comparison, the Midwest ISO recently released an estimate of the *actual gross* benefits from implementing centralized dispatch across the footprint. According to this study, the implementation of the "Day 2" energy markets in the Midwest resulted in *actual gross*

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1 Midwest ISO Informational Filing, April 3, 2006, p. 4.

2 These are the draft net amounts presented in the April 3, 2006, Midwest ISO Informational Filing. These estimates were increased slightly to a range of $88 to $183 million in the February 15, 2007 Midwest ISO Ancillary Service Market filing.

*annualized benefits* of $70 million for the first year of operation.[3] The same study concluded that the estimated potential benefits were $325 million, meaning that 22% of the potential benefits were realized from actual operation. Thus, there are potentially $255 million of unrealized gross benefits from the current market – without the creation of a single market for ancillary services or the filing of a single tariff change. More importantly, is that for the first year of operation the realized benefit from implementing the energy markets did not outweigh the Midwest ISO administrative costs to run those same markets. Ultimately market participants will absorb this net cost. There is little argument that better coordination of energy and ancillary services will yield theoretical benefits, but actual results suggest that it is prudent to apply a potentially steep discount to theoretical estimates of benefits, especially in the early years.[4] An important question remains unanswered in the Midwest, why hasn't the implementation of centralized dispatch resulted in actual savings that are close to those predicted by the US Department of Energy,[5] ICF Consulting, and even the Midwest ISO itself?[6] Until that question is resolved it is premature to consider adding significant complexity to the existing dispatch process and existing markets. With respect to the specific market design proposal of the Midwest ISO, it is not obvious that the theoretical benefits will translate into actual benefits to market participants.

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3 "Independent Assessment of Midwest ISO Operational Benefits". Prepared by ICF International, February 28, 2007 at p. 76.

4 "Independent Assessment of Midwest ISO Operational Benefits". Prepared by ICF International, February 28, 2007 at p .83.

5 "The Potential Impacts of a Competitive Wholesale Market in the Midwest: A Preliminary Examination of Centralized Dispatch", October 2004. Bernard C Lesieuture, Emily Bartholomew, Joseph H. Eto. Lawrence Berkeley National Laboratory, Douglas Hale, Energy Information Administration and Thanh Luong Federal Energy Regulatory Commission. Ernest Orlando Lawrence Berkeley Laboratory, Environmental Energy Technologies Division prepared for the Office of Electric Transmission and Distribution, U.S. Department of Energy.

6 Testimony provided by Ronald R McNamara in FERC Docket No. EL04-104-000.

## IV. THE NEED FOR THE MIDWEST ISO TO IMPLEMENT THE ANCILLARY SERVICE MARKETS

7. Putting aside for the moment the general question of whether any ancillary services markets should be put in place, my expert opinion is that this proposal should not be put in place at this time. Consider first, why "ancillary services" are a necessary part of system operation. The need for ancillary services arises because: (1) matching supply and demand in electricity must occur almost instantaneously and (2) it is neither technologically feasible nor commercially practicable to price changes that occur in supply and demand at every instant in time. In other words physics requires that supply and demand be in constant equilibrium and it is neither feasible nor desirable to establish a price at every instant in time such that any change in either supply or demand would be signaled to the market in order to elicit the appropriate response from market participants. Presumably, if the system operator could create a price at every instant in time – and providing that market participants could respond to this "all inclusive price" instantly – then there would be no need for ancillary services. Since an "instantaneous price" is not feasible, there must be some mechanism for dealing with events that are not priced in the energy market. There are, in fact, many different ways to coordinate energy and ancillary services – including the current methodology used in the Midwest – the question is not whether there should be a market, but rather, compared to the current methodology, are there alternative cost effective mechanisms for the provision and coordination of electricity and ancillary services in the Midwest? The answer to that question is "yes".

8. It is important to remember that the current methodology for ancillary services in the Midwest has operated reliably. As stated by the Midwest ISO,

> The Midwest ISO's Transmission System has been operating and continues to operate reliably during the first year of Energy Markets operations. In accordance with the requirements of their NERC Regions, the twenty-six Balancing Authorities within the Midwest ISO Region continue to meet their Operating (or Contingency) Reserve requirements, to deploy those reserves, and to provide Regulation services. The Midwest ISO, in its role as the Reliability Authority, monitors the performance of each of the Balancing Authorities against their standard.[7]

The recent ASM Filing[8] does not change this conclusion.

9. It is also important to keep in mind that the proposed filing is not necessary to increase competition. Again as stated by the Midwest ISO in its Information Filing to FERC on April 3, 2006:

> The Midwest ISO's Energy Markets have been competitive in their first year of operation. Energy prices have been stable, and are comparable to those of surrounding markets like PJM. The number of Market Participants continues to increase, and the Independent Market Monitor ("IMM") has not reported or mitigated any anti-competitive conduct of the Balancing Authorities, including any undue withholding of capacity for Operating Reserves or Regulation from the Energy Markets. As such, the Midwest ISO concludes that the current configuration of Balancing Authorities has not adversely affected competition.[9]

In the ASM Filing, the Midwest ISO did not alter this position.

10. Finally, the ASM proposal is not necessary to enhance the independence of the Midwest ISO. Again, according to the Midwest ISO:

> Consistent with its obligations as a Regional Transmission Organization ("RTO"), as well as an ISO, the Midwest ISO has maintained its independence in operating the Transmission System

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7 April 3, 2006 Informational filing by the Midwest ISO, p. 6.

8 February 15, 2006.

9 April 3, 2006 Information Filing by the Midwest ISO, p. 9.

> and the Energy Markets. With regard to market operations, the EMT effectively establishes the parameters of the Midwest ISO's independence and the nature of its interactions with Market Participants. With regard to reliability, the authorities assigned to the Midwest ISO (e.g. Reliability Authority) by NERC and its regional reliability organizations establish the parameters of the Midwest ISO's independence and the nature of its interactions with the Balancing Authorities. This relationship is further defined by the BA Agreement between the Midwest ISO and the Balancing Authorities in the Midwest ISO Region. The Midwest ISO sees no evidence that its independence has been undermined in any way by the multiple Balancing Authority configuration in its region.[10]

No change from this position is presented in the ASM Filing.

11. Accordingly, the primary basis for the ASM as proposed is economic benefits. As presented in the April 3, 2006 Informational Filing on the Consolidation of Control Areas, the Midwest ISO has provided analysis that projects a net annual benefit to the market of between $82 and $177 million. The ASM Filing itself references a net annual benefit of between $88 million and $183 million.[11] If, however, these projections of benefits are not realized for whatever possible reason, the premise behind the ASM as proposed is undermined, and increases the probability that ratepayers may be harmed by a project whose costs do not produce savings.

## V. COMMENTS ON THE MIDWEST ISO CONTROL AREA CONSOLIDATION COST/BENEFIT ANALYSIS

12. I agree that a more explicit recognition of the interdependency between ancillary services and energy in the Midwest will create the potential for increased operational

[10] April 3, 2006 Information Filing, pages 9 - 10.

[11] Page 2 of the Filing Letter accompanying the ASM Filing.

efficiencies. It is a separate question of whether or not these operational efficiencies will translate into net benefits to the market. Also a separate question – and one worth investigating – is the extent to which these benefits, should they arise, might flow to load without regulatory intervention. If load is expected to pay a share of the costs and absorb part of the risk of unrealized gains, then they should be assured of a return. There is no inherent economic reason why these benefits should flow directly and only to the "supply-side" – including DSM resources – of the market. In a competitive marketplace, improvements in technology[12] ultimately result in lower costs, lower prices and increased consumer surplus.

13. In contrast to the current, de-centralized approach to procuring and deploying operating reserves, the Midwest ISO has proposed to integrate Operating Reserves into the Day Ahead and Real Time Markets through the simultaneous co-optimization of energy and operating reserves. In addition to the simultaneous co-optimization the Midwest ISO proposes to: (1) construct a "demand" curve for operating reserves in order to determine the "market" price of reserves, (2) integrate scarcity pricing to provide improved "market" signals, and (3) better integrate demand response into both the energy and operating reserve market.

14. Simultaneous co-optimization is certainly a theoretically elegant solution. Moreover, FERC has approved, and other RTOs have implemented, the administered demand curve approach. Obviously, any move toward improved price signals and greater

12 Regional co-optimization can be interpreted as a technological improvement.

demand side participation is a positive step. But the real question -- the one that deserves the most attention from regulators and market participants alike – is whether this particular market design and implementation program will result in actual, rather than theoretical benefits. In other words, is this "market" design likely to deliver benefits in the real world? Often, but not always, theoretical elegance comes at a price. And the price in this case is complexity, which is not necessarily a bad thing, but as a general rule "markets" prefer simplicity to complexity. More correctly, markets produce better outcomes the simpler, more transparent, and less discretionary the rules are. While simplicity is preferred to complexity, no market should be more or less "simple" than it needs to be. There is no doubt that the proposed Midwest ISO ASM design is complex. Indeed, nowhere in the filing is the market described as "simple". Nor does it appear that this was a consideration, let alone a criterion, in the design process.

15. From an economic perspective, efficiency is largely a relative and not an absolute concept because it depends on prices. Thus while a certain technology may have an absolute advantage in converting a specific input fuel into electricity whether it is more or less efficient than another technology depends on the relative prices of the input fuels. With respect to the ASM design, the current methodology used in the Midwest is based on local deployment of reserves by the Balancing Authorities, which is certainly less "efficient" than simultaneous co-optimization at a regional level – all other things equal. But all other things aren't equal, i.e. things other than just the dispatch methodology change under the proposed market. In particular, the prices of ancillary services in the current methodology are fixed and known in advance under the tariff. As a result, bi-

lateral contracting between two parties can potentially ignore the effects of ancillary services. They are simply an add-on, either included by the seller or paid by the buyer of energy.

16. The "cost" of having this certainty is that the dispatch of ancillary services may not be as efficient as it could be and the host utility bears financial risk that they must recover. Implementing the proposed ASM will fundamentally alter the existing structure and commercial relationships and will move risks to different parties. A priori this is neither good nor bad but recognizing this fact implies that a deeper understanding of the consequences from this change are required.

17. In contrast to the current "market" structure, there will be a price established for operating reserves on both a day ahead and real time basis. Certainty will be replaced with probability, and risk will be transferred from the host utility to the "market." Whether this change results in a net price rise or decrease depends on several factors. Specifically although the more efficient dispatch will likely put downward pressure on aggregate production costs across the footprint and possibly prices, there are several factors that are likely to create an upward pressure on the price of both energy and reserves and may serve to increase costs. First, and most obvious, is that currently, the price of reserves is related to average rather than marginal cost and under the proposed design there will be a single, albeit locational, market-clearing price. Assuming that in most cases, marginal cost is greater than average cost and that competitive pressure – in combination with the market monitoring and mitigation plan – will push offers to

approximate marginal cost implies a potential upward pressure on prices. Second, integrating energy and reserves into the dispatch algorithm on a regional basis, while more efficient, is likely to produce greater uncertainty with regard to future prices. It is likely[13] that the variance of the "total" price of energy and reserves will increase and this should put upward pressure on prices as market participants include this risk in their forward price curves. Third, even assuming a perfectly executed dispatch relative to current operations, it is more likely the results will be less intuitive – as is often the case in a non-linear system and even more so when results are derived from linear approximations of that system - to market participants since the dispatch and commitment algorithms will have greater scope. It is rational to anticipate that participants will place a risk premium and hence a higher price on outcomes that are even more affected by algorithms that they only partially understand. Fourth, the exposure to dispatcher discretion and the potential affects on price from the exercise of this discretion is greater. Even if totally unwarranted, it would be prudent for a market participant to factor in a risk premium which accounts for what could happen as a result of dispatcher discretion. Fifth, to the extent that there are misunderstandings on the part of the market about either the rules or their implementation this will cause participants to build in a risk premium potentially resulting in higher prices. Sixth, the increased uncertainty about prices will likely cause forward prices to rise and will put downward pressure on the term length of

[13]The variance of the sum of two random variables, in this case the energy and reserve prices, is equal to $\sigma^2_{ep+rp} = \sigma^2_{ep} + 2\sigma_{eprp} + \sigma^2_{rp}$ where $\sigma^2_{ep+rp}$= the variance of the total price of energy and reserves, $\sigma^2_{ep}$ – the variance of the energy price, $2\sigma_{eprp}$ is the covariance between the energy and reserve prices and $\sigma^2_{rp}$= the variance of the reserve price. Even though it may be "inefficient" since the price of reserves is fixed for a specified period of time, its variance is zero as is the covariance between the reserve price and the energy price.

forward contracting. This in turn is likely to increase the reliance on the Day Ahead and Real Time energy markets at the expense of long-term bi-lateral contracting.

18. In short, in evaluating whether the ASM proposal is likely to provide actual benefits to the market, we must look at how the overall market will respond to the new rules and not just whether the dispatch will be more efficient. It is almost tautological that regional co-optimization will result in a more efficient dispatch. If, however, as a result of the new market design uncertainty increases and this leads to even small increases in prices, then the predicted net benefits – as compared to the current methodology – could be eroded substantially or perhaps even eliminated.

19. One other factor that should be mentioned is that the Midwest ISO markets were not established after a history of "pooling" arrangements. In effect, the market is a patchwork quilt of somewhat isolated electrical islands. Two relevant characteristics arise as a result of this history. First, relative to other RTOs that evolved from "power pools" the Midwest has an extraordinarily high amount of baseload generation capacity. Hence the value of re-dispatch through regional security constrained economic dispatch is limited. Second, the physical transmission system does not have the degree of interconnection that is present in other markets. While LMP-based dispatch conducted by the Midwest ISO will create better price signals resulting in more efficient investment that will ultimately produce a more integrated system, until this occurs, participants should condition their expectations regarding the extent to which centralized, and now potentially co-optimized, dispatch and commitment of the existing physical assets can

deliver benefits. In the final analysis perhaps the greatest initial benefit from implementing the Day 2 energy markets arises not so much from gains in operational efficiencies but from the creation of a robust transparent price signal that better informs investment. And if this is true, there is even more reason to make sure the current market is performing as well as it can and that changes to the design are evaluated at least as much by their effects on operational efficiency as they are on how they might impact the wider marketplace.

## VI. THE RISKS TO THE MARKET OF IMPLEMENTING THE PROPOSED ASM

20. The Midwest ISO is the first RTO to move directly from local dispatch to regional centralized dispatch without passing through a period of pooling arrangements. While this was a monumental achievement on the part of the Participants and Staff at the Midwest ISO, it is clear there are issues that need to be examined and possibly changed in order for the market to realize the projected gains in efficiency of moving to centralized dispatch. These projected efficiency gains are not speculative; they result from improved management of the transmission system through more transparent, timely and granular "instructions" arising from LMP-based dispatch. While it is possible that the pre-market projections by DOE and the Midwest ISO were too optimistic, i.e. they underestimated the efficiency of pre-market operations, it is more probable that the learning curve for both Market Participants and the Midwest ISO is steeper than originally expected.[14]

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14 "Independent Assessment of Midwest ISO Operational Benefits". Prepared by ICF International, February 28, 2007. P.83.

21. The greatest risk to the overall market from implementing the ASM project is that the added complexity contributes to a failure of the market component (as compared to the dispatch component) of the Day 2 energy markets as a result of (1) greater un-hedgeable risk, i.e. uplift, (2) reduced liquidity as participants hedge their exposure to the "ASM enhanced" Day 2 markets with greater reliance on physical rather than financial positions, and (3) higher and more volatile prices. IPL as well as other market participants benefit from, and wish to participate in, well functioning electricity markets that deliver actual benefits. Given the potential caveats that arise from how the energy and ancillary service markets will work in reality, the projected theoretical net benefits of $88 to $183 million dollars is potentially well within the margin of error. There is need in this discussion to look at the issues from the perspective of a Market Participant and focus on questions such as what is the likely effect of this design on the forward curve, will this reduce the potential number of counterparties, what aspects can or cannot be hedged, how understandable are the dispatch outcomes, etc? In other words, while it is convenient to talk about "the" market it is easy to forget that there are actually many interrelated markets that rely and respond to information. Conceptually the aggregate of these markets is "the" market and it is much broader than dispatch and the associated Midwest ISO administered Day Ahead and Real Time markets. From an overall Market perspective, the Midwest ISO administered markets, while an important piece of the overall puzzle, should never be the "primary" markets rather they should be balancing markets where "overs and unders" from bilateral contracts are filled. Just as the

interdependency between energy and ancillary services should be recognized, so too should the relationships between all the markets.

22. This concludes my affidavit.

The foregoing affidavit is true, correct, accurate, and complete, to the best of my knowledge, information and belief.

Ron R McNamara

Dr. Ronald R. McNamara

County of Franklin
State of Ohio

Subscribed and sworn to before me, the undersigned notary public this 29th day of March 2007.

Michelle L Tenney
Notary Public

My Commission Expires 10/23/2011

MICHELLE L. TENNEY
Notary Public, State of Ohio
My Commission Expires 10-23-2011

# ATTACHMENT F

Midwest ISO
We manage power.

# EEI CEO Meeting

March 22, 2007
Washington, DC

# Discussion Outline

Midwest ISO
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- Winter 2006 Performance & Summer 2007 Preparation
- ICF Benefit Study Update
- Ancillary Services Market (ASM) Initiative Update

# Midwest ISO Evolution

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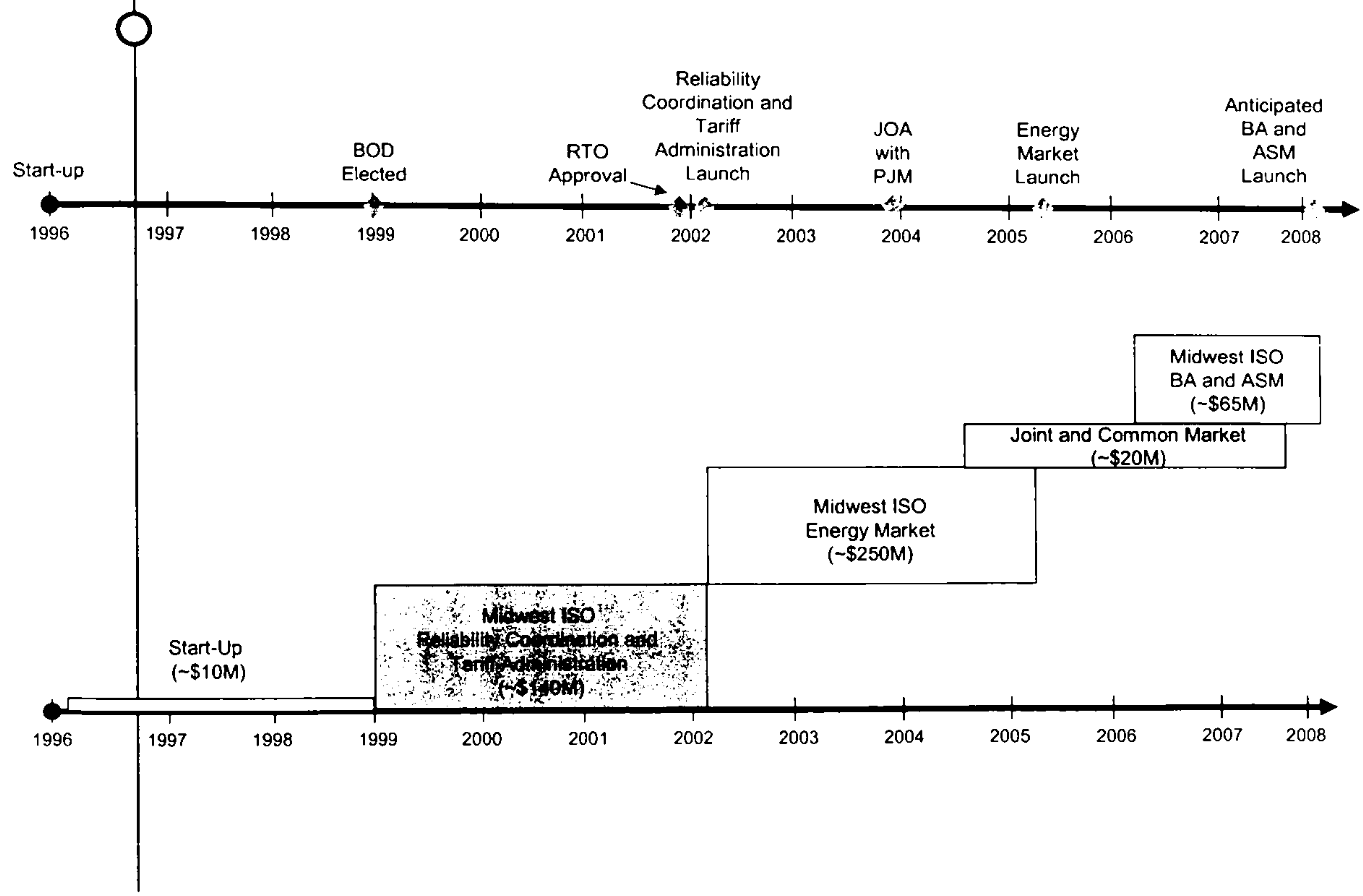

# Winter 2006/2007 Performance

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- Preparation
  - Midwest ISO and Balance Authorities projected extreme temperatures and high loading for week of February 5th
  - Surveys initiated regarding unit availability and expected fuel supply issues
  - Using all information available, Midwest ISO developed plan to meet demand
- Notification
  - Midwest ISO conducted conference calls with Balancing Authorities, Transmission Owners, Reliability Coordinators, State Commissioners, NERC and Midwest ISO member companies
  - Communicated system status throughout period – outages, loads, reserves, constraints and issues
  - Emergency Energy Alert level 2 (EEA-2) was declared for the morning and evening peaks on February 5th and 6th
- Lessons Learned
  - Partial curtailment of interruptible load proved to be effective tool
  - Public posting of Conservative System Operations procedure was required
  - Price setting mechanism is required for appropriate market signal

# 2007 Summer Readiness

Midwest ISO
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- Lessons learned from 2006 summer resulted in notable progress in the areas of:
  - NERC & Emergency operating procedures (EOP) alignment
    - Adequate Ramp Capability (ARC) procedure
    - Conservative System Operation
    - Demand response
    - Behind-the-meter generation
    - Deployment protocols
    - Day-Ahead and Real-Time Sufficiency Reports
  - Communication protocols and mediums
    - Communication messages and protocols will provide more clarity and coordination between the Midwest ISO and all stakeholders
  - Available Capacity
    - Seasonal ratings
    - Permanent de-rates
    - Operating restrictions (environmental and fuel)
- Conducted post-Winter 2006/2007 workshop on March 12th to determine lessons learned; Summer 2007 Readiness Workshop scheduled for April 30th, 2007
- Contingency Reserve Sharing Group (CRSG) and the Adequate Ramp Capability (ARC) in place will provide more flexibility to meet summer 2007 peak requirements

# ICF Benefits Study

Midwest ISO
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- Summary results presented to Board of Directors and Stakeholders on February 15th, 2007 with full report complete by the end of February
- What the ICF Study Is:
  - Focus on subset of operational benefits and reflection on performance
    - Regional unit commitment & security-constrained economic dispatch
    - Improved utilization of transmission assets
  - Tool to evaluate trends in market benefits and outcomes at "high-level"
- What the ICF Study Is Not:
  - Precise indication of how Midwest ISO market actually performed
  - A rate case-quality tool for states in the Midwest ISO footprint
  - Tool that can be utilized to answer questions for individual generation units or the corresponding Balancing Authority
- Lessons Learned:
  - A confluence of factors led to 100% of centralized dispatch benefits not being realized
  - Centralized unit commitment is a key driver of market benefits
  - Associated with improved ability to displace gas with coal, more efficient use of coal and better use of import potential is important
  - While benefits were small during initial start up, improvement demonstrated towards the end of the period (in the face of record gas and coal prices)
- Midwest ISO, at the request of the EEI CEO's, instructed ICF to conduct an 5 additional months (April through August 2006)
  - Initial indications are that the results show a similar trend as the final three months of the previous study

# ICF Study – Summary Results
## June 2005 through March 2006

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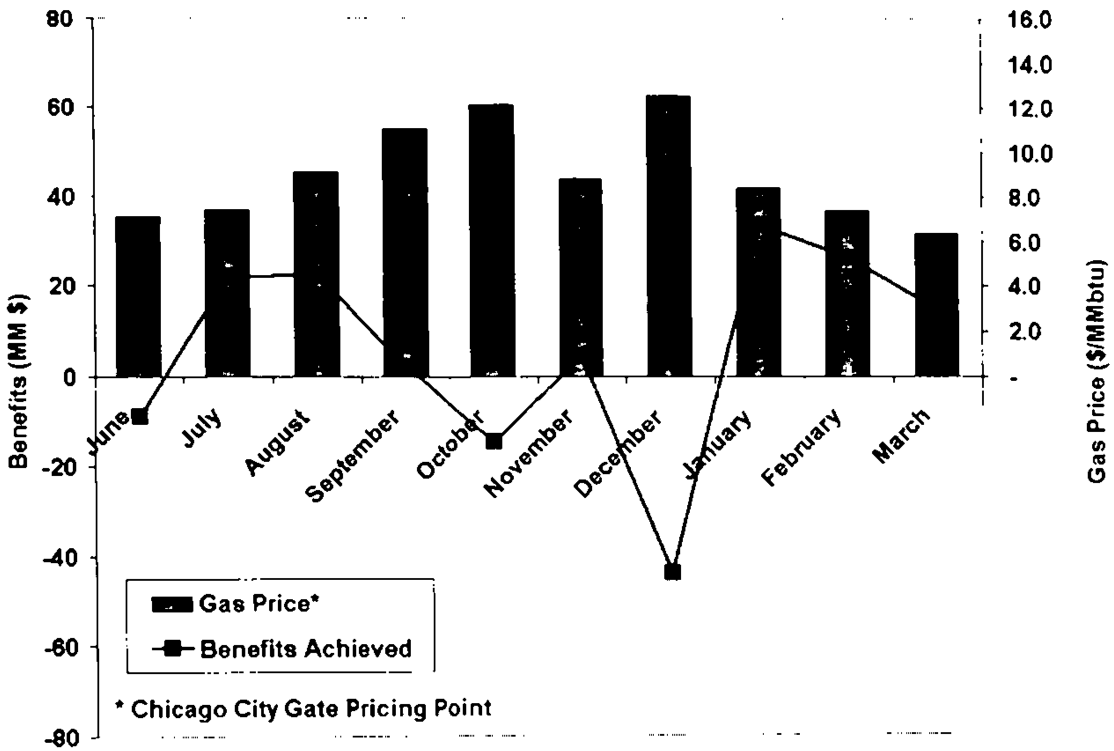


* Chicago City Gate Pricing Point

| Summary (MM$): | |
|---|---|
| Theoretical Max | $460 |
| ASM[1] | ($189) |
| Achievable | |
| Theoretical | $271 |
| **Actual** | **$ 58** |

[1] Ancillary Services Market (ASM) Theoretical Value calculated by ICF. Given that the Midwest ISO has not launched the ASM initiative, these should not be included in actual achievable results. Note that the ASM theoretical value generated by ICF is within the range of the Midwest ISO value estimates generated and shown in the April 3, 2006 Filing to FERC (EL06-___-00). The ASM Market Potential Benefits are shown in the filing as $113 to 208m.

# Ancillary Service Market (ASM) Initiative

Midwest ISO
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- The Midwest ISO, working in conjunction with Stakeholders, continue to enhance both the reliability of bulk power system and market operation performance

- The proposed modifications to Midwest ISO Tariff will fulfill the outstanding requirements of the FERC order designating the Midwest ISO the nation's first Regional Transmission Organization ("RTO"), namely the implementation of a market-based mechanism for providing ancillary services

- The proposed tariff modifications are designed to:
  - Reduce fuel and O&M costs associated with the provision of regulating and contingency reserves
  - Facilitate the transfer of certain Balancing Authority functions to the Midwest ISO
  - Provide for efficient acquisition and pricing of regulating reserves and contingency reserves (collectively, "Operating Reserves")
  - Provide a platform for incorporating Demand Responsive Resources into the efficient and reliable supply of wholesale power

# ASM Cost and Benefits

Midwest ISO
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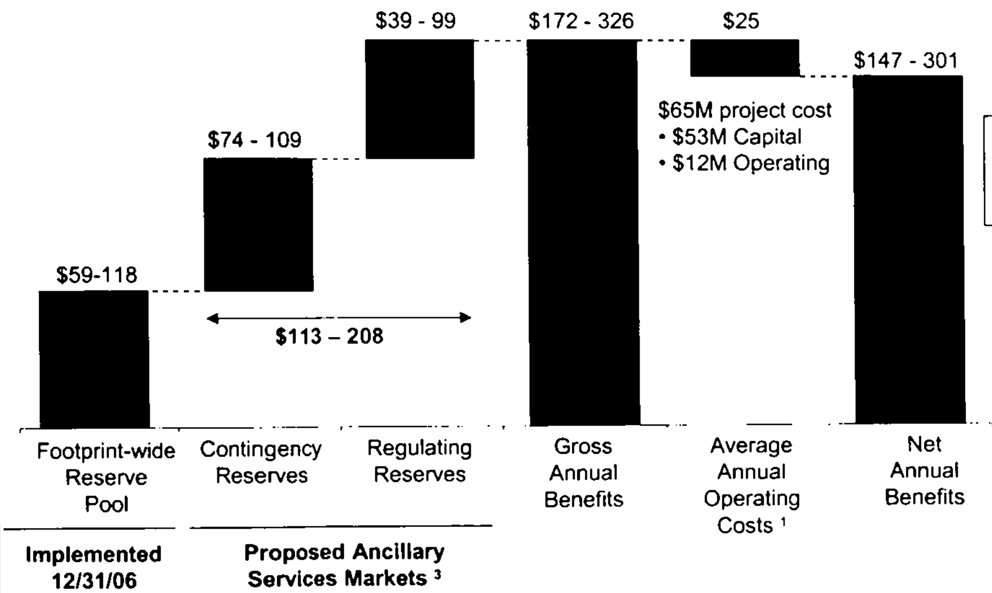
## Estimated Annual Benefits ($ Millions)




| | Low | High |
|---|---|---|
| NPV [2] | $990 | $2,456 |
| IRR | 583% | 1,299% |

**Source: Midwest ISO April 3, 2006, FERC Compliance Filing**

[1] Recovery through existing Midwest ISO Schedule 17; includes operating expenses, depreciation and interest expense.

[2] NPV calculated over 10 years using 5% discount rate

[3] The ICF International study studied the potential benefits associated with *Post-Midwest ISO ASM* indicating approximately $189 million in gross benefits over a ten-month period, which annualize to approximately $227 million

# Description of ASM Benefits

Midwest ISO
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Two categories of benefits in addition to Midwest Contingency Reserve Sharing Group benefits:

- Contingency Reserves under single Balancing Authority
  - Contingency Reserves are spinning reserves and supplemental or quick start reserves
  - Benefit expected based on reduction in fuel and O&M costs for the region as a whole
  - Fuel and O&M cost savings achieved by meeting regional reserve requirement with lowest cost generation as opposed to meeting 27 separate Balancing Authority reserve requirements using lowest cost generation under the control of each Balancing Authority
  - Up to 700 MW of reserves held by Midwest ISO at peak hour reduced 50% to 75% by centralizing reserves under single Balancing Authority

- Regulating Reserves under single Balancing Authority
  - Reserves required to meet Area Control Area ("ACE") requirements reduced by 30% to 45% based on consolidation into single regional ACE
  - Current average ACE is 1,460 MW based on "Regulation Up" on existing units
  - Fuel and O&M cost savings achieved by reducing amount of generation committed to meet ACE obligations with no reduction in system reliability

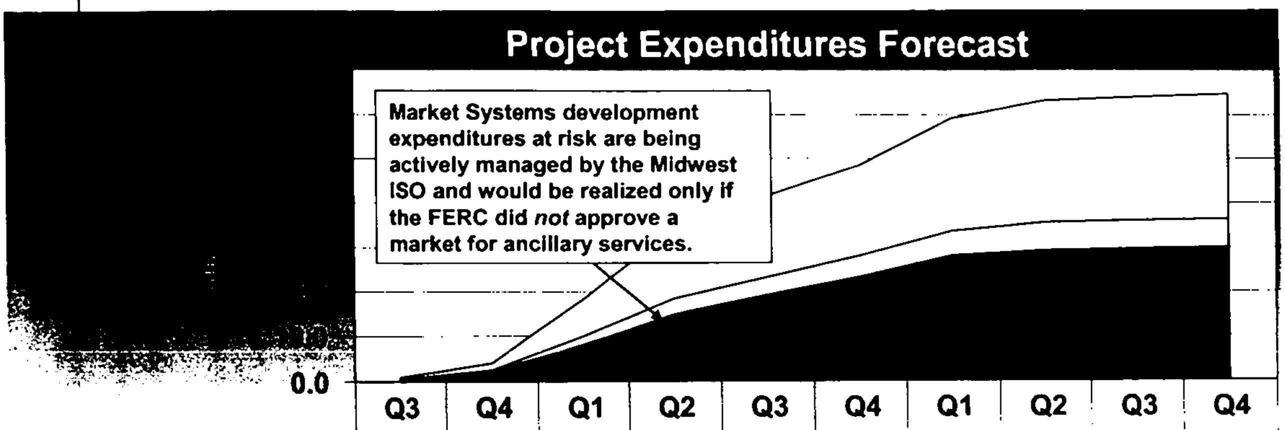
# Risks Associated with FERC Order

Midwest ISO
We manage power.

- The Midwest ISO is proposing to implement an ASM that features simultaneous co-optimization of Energy and Operating Reserves
- Key risks associated with implementing simultaneous co-optimization were:
  - Ability of hardware and software to perform necessary calculations within required 5 minute interval
  - Ability to exchange data to and from the Midwest ISO and Local Balancing Authorities Energy Management Systems within required 2-4 second interval
- Midwest ISO conducted proof-of-concepts tests of both the hardware and software and data transfer latency during 2006
  - Hardware platforms are capable of meeting processing speed requirements
  - Software algorithm tested using actual data for 1,500 commercial pricing nodes and 1,200 generators with solution achieved within 5 minute interval
  - Data exchange capability individually verified with each Local Balancing Authority and the Midwest ISO Energy Management Systems within required 2-4 second interval
- Results from proof-of-concepts were factored into infrastructure and software design requirements
- Anticipated potential key design modifications from FERC Order have been incorporated into software development requirements via configurable input parameters
  - Dispatch instructions sent from the Midwest ISO to generators have deviation bandwidth parameters which can be expanded of contracted
  - Scarcity Pricing and Value of Lost Load thresholds and values are enterable parameters by Midwest ISO

# ASM - Forecasted Spending Rate

Midwest ISO
We manage power.




| | 2006 Q3 | 2006 Q4 | 2007 Q1 | 2007 Q2 | 2007 Q3 | 2007 Q4 | 2008 Q1 | 2008 Q2 | 2008 Q3 | 2008 Q4 |
|---|---|---|---|---|---|---|---|---|---|---|
| □ Energy Mgmt' System | 0.2 | 1.5 | 8.6 | 16.0 | 18.3 | 20.4 | 25.5 | 27.5 | 28.0 | 28.6 |
| □ Business Continuity | 0.1 | 0.4 | 1.9 | 3.4 | 4.2 | 4.8 | 5.9 | 6.3 | 6.4 | 6.5 |
| ■ Market Systems | 0.4 | 2.1 | 8.2 | 14.9 | 19.2 | 23.2 | 27.8 | 29.4 | 29.6 | 29.9 |
| Cumulative | 0.8 | 4.0 | 18.6 | 34.3 | 41.6 | 48.4 | 59.3 | 63.1 | 64.1 | 65.0 |
| ■ Market Systems (No go at risk development dollars) | 0.0 | 0.1 | 1.1 | 3.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

# Midwest ISO Administrative Fees
## Five Year Forecast

Midwest ISO
We manage power.

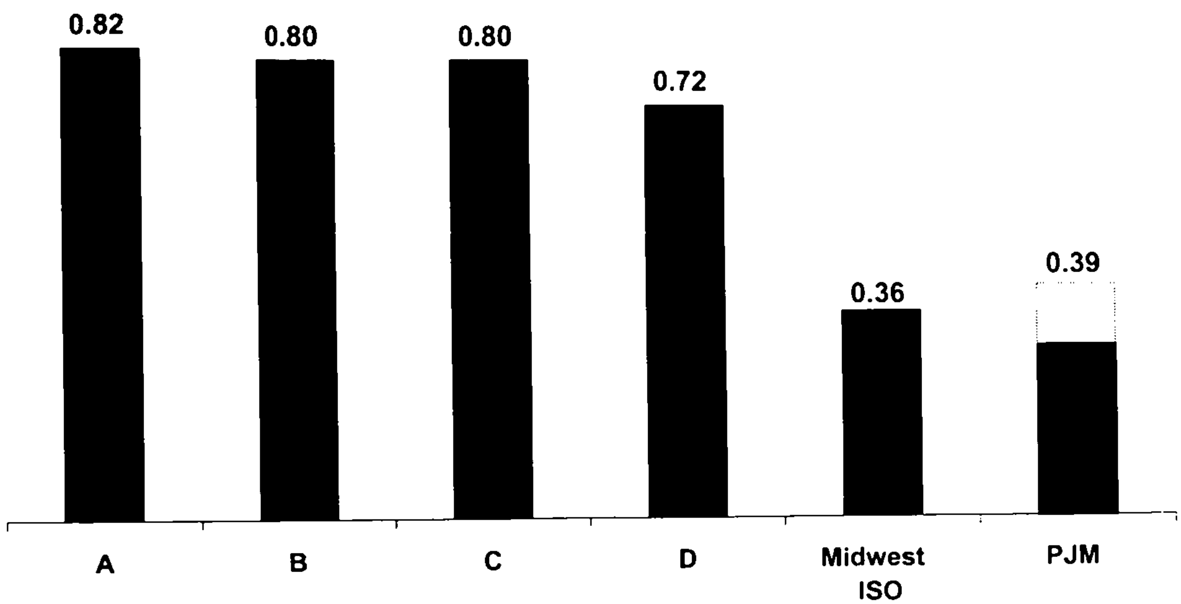
| | Day 1 Schedule 10 | Day 2 Schedule 16 | Schedule 17 | | | | | Revised Total |
|---|---|---|---|---|---|---|---|---|
| Year | Rate per MWh of Energy | Rate per MWh of Energy | MWh (000's) | Ancillary Markets Annual Cost (000's) | Base | Ancillary Markets Adder[1] | Total | Rate per MWh of Energy |
| 2008 | 0.144 | 0.025 | 663,864 | $ 21,202 | 0.171 | 0.032 | 0.203 | 0.373 |
| 2009 | 0.128 | 0.025 | 677,142 | $ 25,610 | 0.167 | 0.038 | 0.205 | 0.358 |
| 2010 | 0.125 | 0.025 | 690,684 | $ 25,746 | 0.169 | 0.037 | 0.206 | 0.356 |
| 2011 | 0.126 | 0.024 | 704,498 | $ 25,562 | 0.169 | 0.037 | 0.206 | 0.356 |
| 2012 | 0.119 | 0.019 | 718,588 | $ 25,392 | 0.143 | 0.035 | 0.178 | 0.316 |

Cost per MWh for all rate schedules calculated using projected Schedule 10 energy

[1] Incremental cost (operating expense + depreciation + interest expense) for development and operation of Balancing Authority functional consolidation and Ancillary Services Markets

# 2006 RTO Revenue Requirement

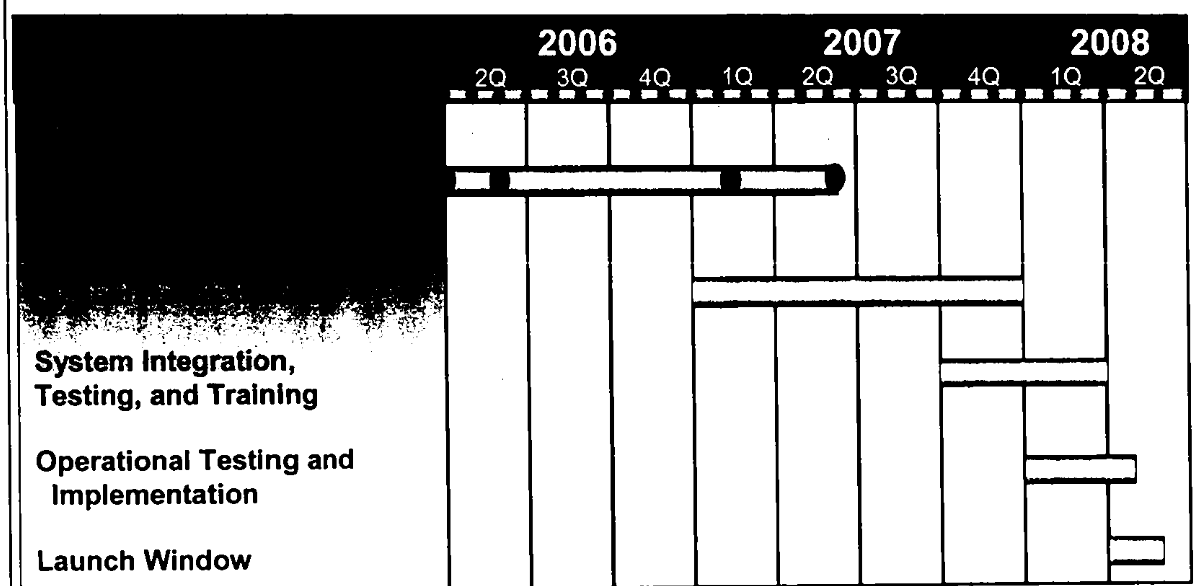
**($ Per MWh of Load)**



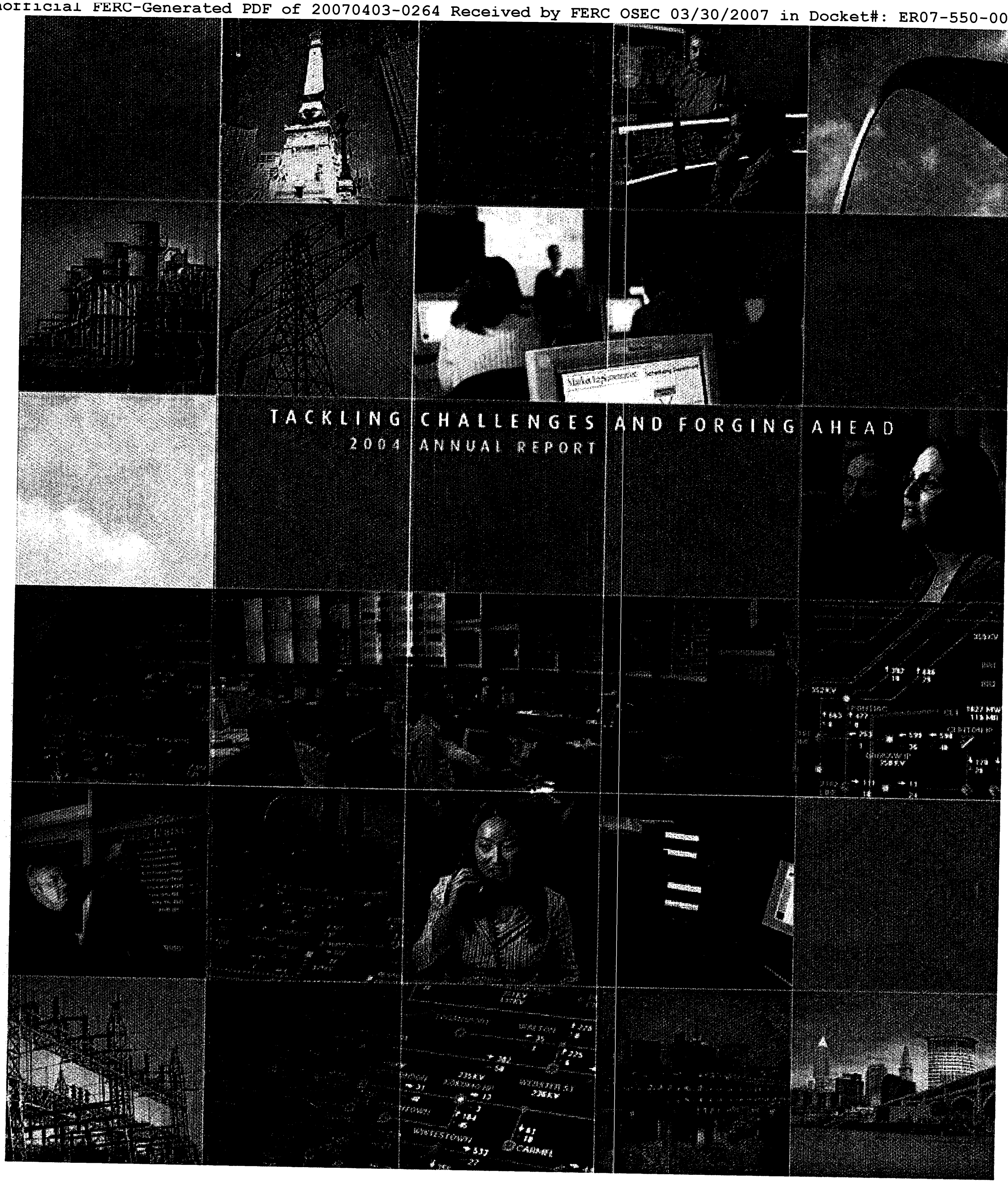

Note: does not include AESO or Southwest Power Pool

# ASM Major Milestones & Timeline

Midwest ISO
We manage power.



# ATTACHMENT G



# TACKLING CHALLENGES AND FORGING AHEAD

## 2004 ANNUAL REPORT

Midwest ISO

We manage power.

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# A MESSAGE FROM THE BOARD OF DIRECTORS

## 2004 was a big year for the Midwest ISO, its stakeholders, and its members. Our primary focus was on reliability and the many and varied tasks we undertook in preparation for the launch of the Midwest Energy Markets, scheduled for April 1, 2005.

To understand the importance of the Midwest Energy Markets, the next step in a rapidly evolving electric industry in the Midwest, a bit of history may be helpful.

For decades, electricity was for the most part generated and consumed at the local level, with a single company generating the power, as well as controlling the transmission lines that brought electricity to end users. Under this system, reliability was also a local issue.

Today, things are much different. Electricity may cross several state lines on its trek from the point of generation to its end-use customer. To manage these cross-jurisdictional transactions, the federal government authorized the formation of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). As an RTO, the Midwest ISO is responsible for overseeing the wholesale power grid that touches 15 U.S. states and the Canadian province of Manitoba. This gives the Midwest ISO a key role in ensuring the reliable transmission of power to more than 15 million customers throughout its region.

With the establishment of the Midwest Energy Markets, the Midwest ISO will take on another significant role that we believe will lead to a considerably more efficient use of generating facilities and transmission services. Open Energy Markets will result in much greater transparency regarding the sale and transmission of power within the region. That, in turn, should put downward pressure on energy prices – and at the same time result in considerably improved management of congestion along the grid.

At the request of the Federal Energy Regulatory Commission (FERC), the Midwest ISO last year conducted an analysis of projected cost savings expected to result from the operation of regional, security-constrained economic dispatch and Real-Time and Day-Ahead Energy Markets featuring Locational Marginal Pricing. Our analysis concluded that implementation of these Energy Markets would allow for more efficient use of the existing transmission and generation assets, which is expected to not only lower spot energy prices, but put downward pressure on prices in bilateral contracts, resulting in a potential annual gross savings of about $713 million to energy consumers.

The establishment of the Midwest Energy Markets is the right thing to do and this is the right time to do it.

As an original Board Member of the Midwest ISO Board, I have had the privilege of governing this organization since its infancy. Our growth and development, particularly over the last 12 to 24 months, has been nothing short of extraordinary. Now, as we prepare to take on this new and important role, I am confident the organization has assembled a team worthy of the trust that we have placed in them.

Over the past two and one half years, more than 115 employees and over 150 consultants have toiled a combined 500,000 hours to complete a variety of trials and tests needed to ensure market readiness. It has been a tremendous amount of work, and our people have rolled up their sleeves and dug in.

To be sure, the road we have traveled this past year has had its share of bumps and twists and turns. But I am proud to say that the Midwest ISO staff has worked with its stakeholders to resolve problems as they have arisen and has tackled challenges with innovation and plain old hard work.

It is not overstating things to say that this organization simply could not have taken on such a task ten years ago, or even two years ago. Technology has advanced to the point where we now have the technical know-how to build and run one of the largest Locational Marginal Pricing (LMP)-based Energy Markets in the world. It truly is remarkable that such a complex undertaking could be achieved, and it is something that myself and the other members of this Board of Directors are mighty proud to be a part of.

I cannot emphasize enough the value this organization places on the ongoing dialogue we have established with our members and other stakeholders. The input we receive from our stakeholders is paramount to our success as an organization – particularly within the last year, as the countdown to the launch of our Energy Markets drew near. Through our monthly Advisory Committee meetings and regular contact with the Organization of MISO States, we remain committed to balancing the needs and concerns of our stakeholders in ways that maximize the benefit of their membership in our organization, while bringing tangible benefits to energy consumers in the Midwest.

For example, we have worked with our stakeholders to reach a mutually agreed upon resolution of how to administer existing Grandfathered Agreements, as well as how to allocate Financial Transmission Rights (FTRs) prior to the start of the Midwest Energy Markets.

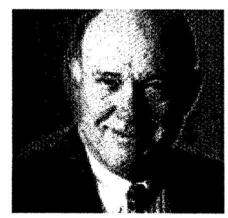
Midwest ISO employees have spent the better part of a year working with our Market Participants on a wide variety of market readiness metrics ranging from registration, creditworthiness, comprehensive training courses, and Day in the Life Enhanced (DILE), Open Loop, Closed Loop, ICCP (Inter-control Center Communications Protocol), and XML (Extensible Markup Language) Testing.

The Board of Directors is proud of this important work and is confident we have prepared Market Participants to the greatest extent possible for the April 1 market launch.

On behalf of the entire Board, I want to extend my thanks to our member organizations, our stakeholders and our government regulators for working cooperatively with us to help us stay the course and achieve our market readiness goals.

The future indeed looks bright for this dynamic organization.

Sincerely,



**James H. Young, Jr.**
Chairman
Board of Directors
Midwest Independent Transmission System Operator, Inc

# A MESSAGE FROM THE PRESIDENT AND CEO

## By any measure, 2004 was a bellwether year for the Midwest ISO.

As I look back, I am proud of the tremendous strides our employees, members and stakeholders have made in preparation for the long-awaited launch of our Midwest Energy Markets on April 1, 2005. Equally important, we continued to implement and refine systems and equipment designed to enhance the overall reliability of the power grid that serves much of the Midwest region.

The theme of this year's Annual Report, "Tackling Challenges, Forging Ahead," sums up the accomplishments we have made and the work that awaits us. Looking forward, I am convinced that with the launch of our Midwest Energy Markets, this organization will live up to the promise and expectations of a Regional Transmission Organization (RTO). I truly believe the best is yet to come.

Over the next two pages, I will highlight some of our significant undertakings and achievements that have given us the ability to better coordinate the facilities we monitor and have paved the way for us to extend the benefits of a regionally managed power grid throughout the Midwest.

### Reliability

"We Manage Power" is more than just a corporate tagline, but a responsibility we take very seriously. Throughout 2004, we continued to make investments in our reliability tools and monitoring capabilities to ensure that the power is there when the people of the Midwest need it. And, as new technology develops within our industry, we will continue to improve upon the foundation we have built in new, innovative ways.

### Upgrades and Improvements

Before the start of peak summer demand, the Midwest ISO certified its reliability action plan to the North American Electric Reliability Council (NERC). This plan, based in large part on the implementation of recommendations NERC made in a February 10 report and an April audit, included an array of system refinements and upgrades. Changes within our control room include installation of an expanded dynamic video projection system and state-of-the-art visualization screens; advanced alarm filtering; and an improved Energy Management System to greatly increase monitoring within our footprint and neighboring reliability areas.

In addition, we initiated a series of enhanced training programs for the Midwest ISO and the Control Areas it serves, including simulations of potential high-risk situations to ensure coordinated, appropriate response. We also modernized our communications systems and formalized communication protocols between the Midwest ISO and the control rooms of Midwest ISO Control Areas and adjoining Reliability Coordinators; clarified command authority between the Midwest ISO, its Control Areas, and adjacent Reliability Councils; and implemented multi-day, next-day and intra-day reliability assessments that will be critically important to the operation of our Midwest Energy Markets.

### Seams Arrangements

The Midwest ISO is leading the energy industry in the development and implementation of improved communications, coordination and information sharing through the signing of detailed seams arrangements. This past May, we announced a multi-regional data exchange agreement between us, PJM Interconnection (PJM) and Tennessee Valley Authority (TVA). The agreement, considered a landmark within our industry, will enhance overall reliability, improve congestion management and adequacy, and increase transparency of the transmission grid for a large portion of the Eastern Interconnection. We are also continuing to work with the Mid-Continent Area Power Pool (MAPP) and Southwest Power Pool (SPP) to achieve a consistent congestion management process that will help mitigate transfers across neighboring borders.

### New Members

AmerenUE and AmerenCIPS, in Missouri and Illinois respectively, were integrated into the Midwest ISO in May while AmerenIP, which also serves electric customers across the state of Illinois, was successfully integrated into the Midwest ISO in late September 2004. Their integration not only brought all three Ameren operating companies' transmission systems into our organization, but simplified and improved the sale of transmission services between MAPP and the East Central Reliability Council (ECAR).

Great River Energy, a generation and transmission cooperative that is the second-largest power supplier in Minnesota, joined the Midwest ISO as a transmission-owning member in December 2004. Great River Energy's voluntary membership brought most of Minnesota into our organization and helped increase overall system reliability by decreasing seams issues.

### Customer Relations

As the Midwest ISO continues to implement new technology and procedures, customer relations will continue to be critical to our success. Our work is facilitated and driven by the many stakeholder representatives who participate on Midwest ISO committees and working groups and attend our monthly Advisory Committee meetings. Their input and feedback was critically important for the delivery of the Midwest Energy Markets, and we look forward to their continued involvement in 2005 and in the years to come.

### Market Readiness and Preparation

2004 signified the home stretch of the Midwest Energy Markets—a project that has been years in the making. Over the past year the

Midwest ISO worked with our Control Areas in a variety of trials and other exercises designed to prepare Market Participants, to the greatest extent possible, before "going live" with one of the largest Energy Markets in the world.

Market Trials began in January 2004 and included several phases:

- Market Participant Interface (MPI) (January 2004)
- Day In the Life Basic (DILB) (March – April 2004)
- MPI Enhanced (May 2004)
- Day in the Life Enhanced (DILE) (September 2004)
- Parallel Operations I (November – December 2004)
- Parallel Operations II (January 2005)
- Final Trials (January – February 2005)
- Mandatory Testing (February – March 2005)

Other key dates and milestones leading up to the launch of our Energy Markets include:

AUGUST 2004 – The Federal Energy Regulatory Commission (FERC) conditionally approved our Midwest Energy Markets Tariff. This tariff sets out the rates, terms and conditions necessary to implement a platform featuring security-constrained, centralized dispatch of generation resources throughout much of the Midwest. Our tariff is consistent with the mandate of FERC Order No. 2000, which requires RTOs to provide Real-Time energy imbalance services and a market-based mechanism for congestion management.

SEPTEMBER 2004 – We began "Day in the Life" market demonstrations, which allowed for a scripted "bid to bill" interchange between the Midwest ISO and Market Participants to more accurately simulate actual market operations. Specific information was made available in the areas of Day-Ahead and Real-Time Operations, OASIS automation, Financial Transmission Rights (FTRs), Physical Scheduling, Market Monitoring, Credit, and Invoicing.

OCTOBER 2004 – Financial Trading Hubs were created to enable Market Participants to transition from their existing bilateral contracts in ways that better reflect our LMP-based Day-Ahead and Real-Time Energy Markets. The three trading hubs – the Midwest ISO Cinergy Hub, the Midwest ISO Michigan Hub and the Midwest ISO Illinois Hub – provided Market Participants with common price indices that gave them greater certainty about how trading will develop under live market conditions. A fourth trading hub, the Midwest ISO Minnesota Hub, was announced in February 2005.

NOVEMBER 2004 – Parallel operations of our Energy Markets allowed Market Participants to continue "Day in the Life" interchanges in an unscripted test of market conditions, using Real-Time production feeds implemented within the Midwest ISO's internal processes on a 24-hour basis. The first tier of the FTR nomination process also began, marking the first time Market Participants made financially binding decisions that would settle when the markets open.

System restoration drills were held in November and December, and included more than 400 participants. NERC received restoration progress updates as part of the exercises, which focused on system assessment, communications protocols, and interconnection procedures following unexpected power outages.

DECEMBER 2004 – We began integrating and operating our current Day-One functions and the Midwest Energy Markets as a consolidated operation. On December 2 and December 9, the Midwest ISO also conducted the first and second of many Systems Operations tests which, while not financially binding, demonstrated the organization's ability to dispatch generation.

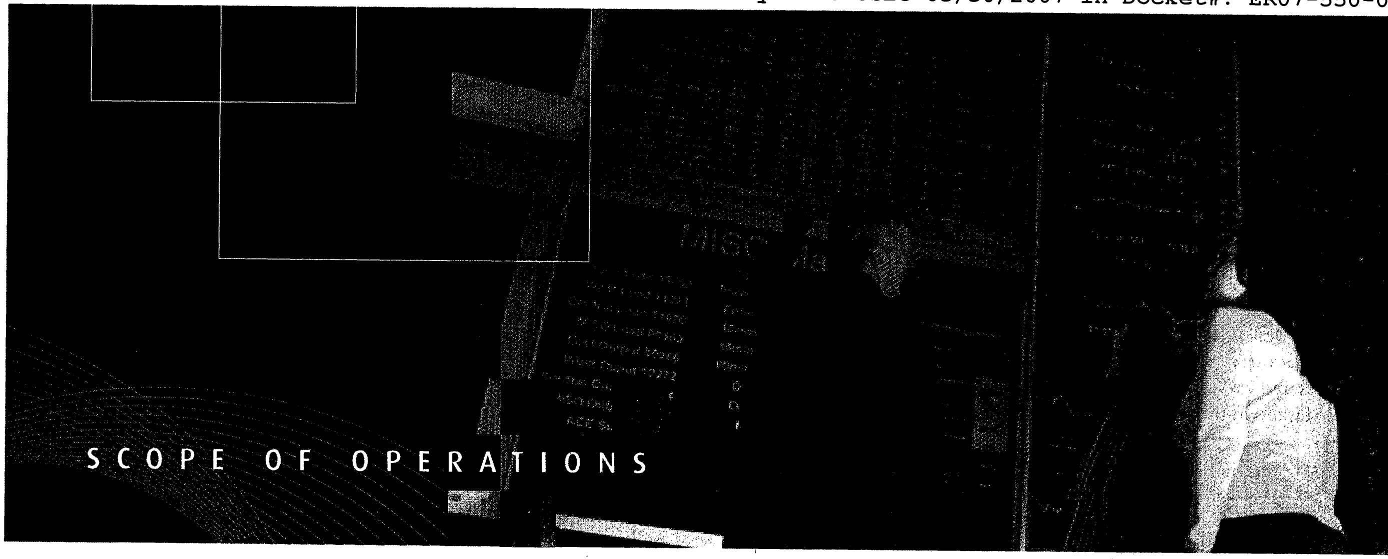
JANUARY 2005–We initiated Parallel Operations II, which incorporated a number of changes included in FERC's orders on our Midwest Energy Markets Tariff.

During January and February, our systems and software were subjected to as many different circumstances, stresses and situations as possible to ensure they were adequately tested and ready for use. As April approaches, I am confident we have completed the tests, training and exercises necessary for a successful market launch.

Through the hard work and expertise of our dedicated employees, the critically important input from our stakeholders, and support from government regulators, we are positioned to launch and operate Energy Markets that will bring tangible benefits to consumers throughout the Midwest.

As President and CEO of the Midwest ISO, I am personally committed to doing whatever it takes to tackle challenges and forge ahead in the dynamic and exciting industry in which we work. In so doing, I am confident we will move closer toward achieving our goal of being the premier RTO.

**James P. Torgerson**
President and CEO
Midwest Independent Transmission System Operator, Inc.




## MIDWEST ISO'S 2004 SCOPE OF OPERATIONS

**OPERATIONS:**
All or parts of 15 states, plus the Canadian province of Manitoba

**AREA SERVED:**
947,000 square miles

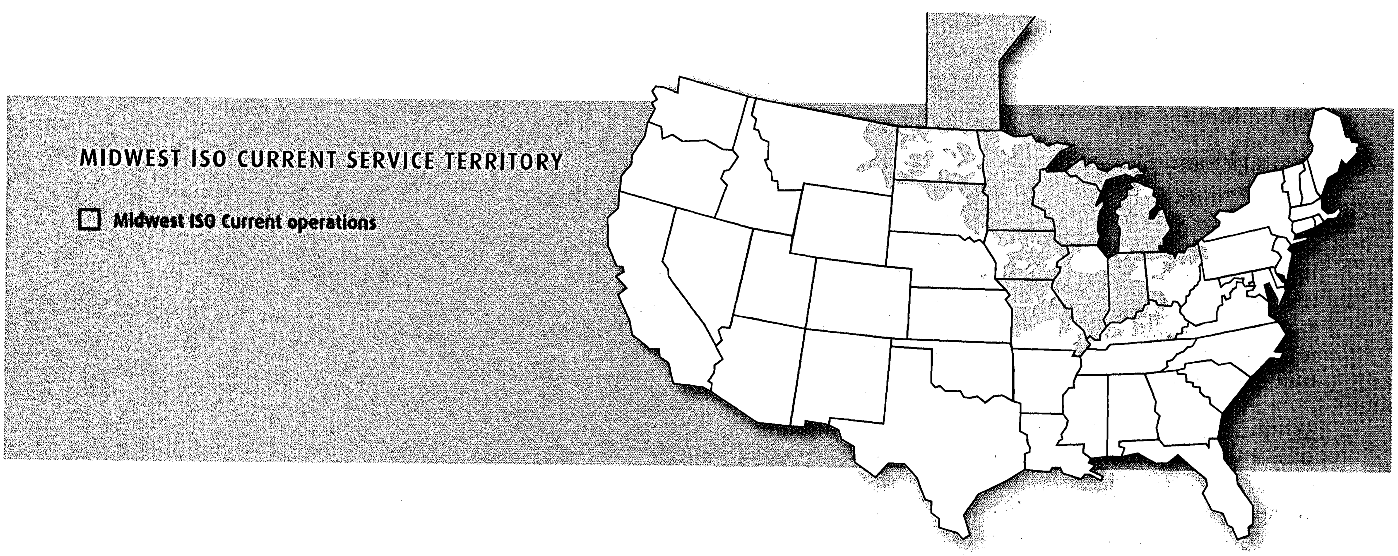
**HIGH VOLTAGE, INTERCONNECTED TRANSMISSION LINES:**
97,000 miles

**INSTALLED CAPACITY:**
131,365 megawatts

**PEAK DEMAND:**
119,207 megawatts

**TWO CONTROL CENTERS:**
Headquarters: Carmel, IN, with additional facility in St. Paul, MN

**TOTAL EMPLOYEES:**
517



## TRANSMISSION OWNING MEMBERS:

**Coordination Company (1)**
Manitoba Hydro

**Vertically Integrated Utilities (13)**
Alliant Energy Corporation *for*
IES Utilities, Inc. and Interstate Power Company
AmerenCILCO
AmerenIP
Aquila, Inc.
Cinergy Services, Inc. *for*
Cincinnati Gas & Electric Company, PSI Energy, Inc. and
Union Light Heat & Power Company
Indianapolis Power & Light Company
LG&E Corporation *for*
Louisville Gas and Electric Company and Kentucky Utilities Company
Minnesota Power, Inc. and its subsidiary,
Superior Water, Light and Power Company
Montana-Dakota Utilities Company
Northwestern Wisconsin Electric Company
Otter Tail Power Company
Vectren Energy *for*
Southern Indiana Gas & Electric Company
Xcel Energy, Inc. *for*
Northern States Power Company (Minnesota) and
Northern States Power Company (Wisconsin)

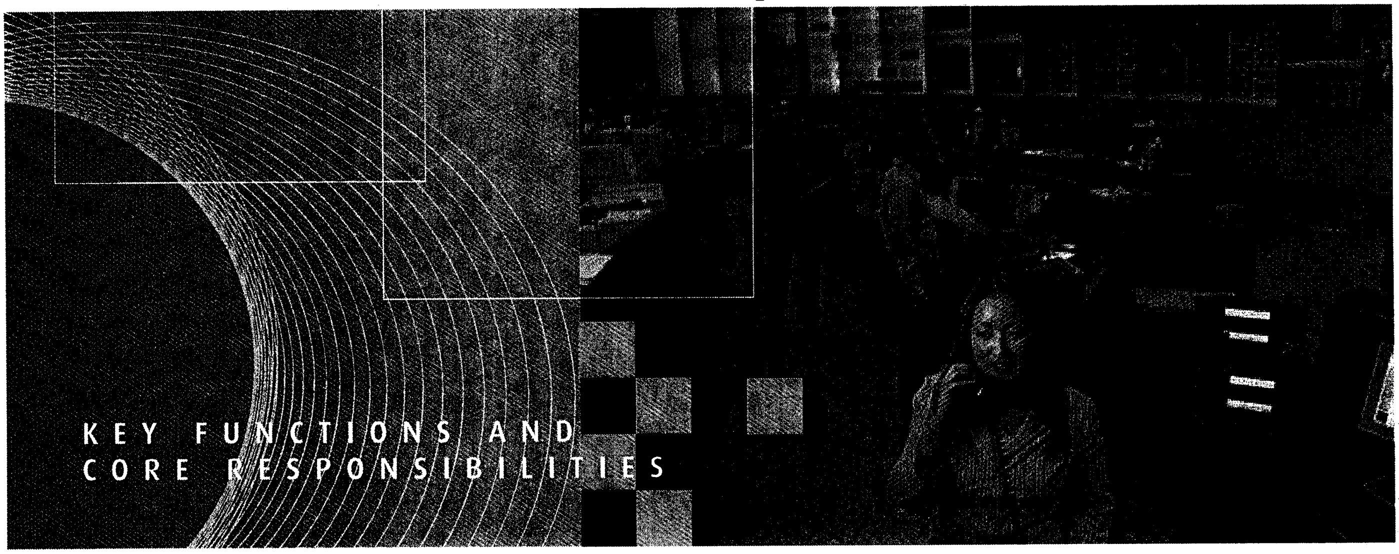
**Municipalities and Cooperatives (9)**
City Water, Light & Power (Springfield, IL)
City of Columbia, MO
Great River Energy
Hoosier Energy Rural Electric Cooperative, Inc.
Indiana Municipal Power Agency
Lincoln Electric System
Michigan Public Power Agency
Southern Illinois Power Cooperative
Wabash Valley Power Association, Inc.

**Stand-Alone Transmission Companies (4)**
American Transmission Company, LLC
GridAmerica Participants:
- AmerenUE and AmerenCIPS
- FirstEnergy's American Transmission Systems, Inc.
- Northern Indiana Public Service Company

International Transmission Company
Michigan Electric Transmission Company, LLC

## NON-TRANSMISSION OWNING MEMBERS (50):

Allegheny Energy Supply Company, LLC
Ameren Energy Marketing
American Electric Power Company, Wholesale
American Municipal Power–Ohio, Inc.
BP Energy Company
Calpine Energy Services, L.P.
Cargill-Alliant Power Markets, LLC
Citadel Energy Products LLC
Cleveland Public Power, Department of Public Utilities
Coalition of Midwest Transmission Customers
Commonwealth Edison Company
Conectiv Energy Supply, Inc.
Constellation Energy Commodities Group, Inc.
Consumers Energy Company
Coral Power, LLC
Detroit Edison Company
Dominion Energy Marketing, Inc.
Duke Energy North America, LLC
Dynegy Power Marketing, Inc.
Edison Mission Marketing & Trading, Inc.
Exelon Generation Company, LLC
FirstEnergy Corporation
Granite City Steel, Division of the U.S. Steel Corporation;
International Steel Group; and Caterpillar, Inc.
Green Mountain Energy Company
Illinois Municipal Electric Agency
J. Aron & Company
Madison Gas and Electric Company
MidAmerican Energy Company
Mirant Americas Energy Marketing, LP
Missouri River Energy Services
Morgan Stanley Capital Group Inc.
NRG Power Marketing, Inc.
Ontario Power Generation Inc.
PPL EnergyPlus, LLC
PPM Energy, Inc.
PSEG Energy Resources & Trade LLC
Quest Energy, LLC
Reliant Energy, Inc.
Ritchie Energy Products
Sempra Energy Trading Corporation
Soyland Power Cooperative, Inc.
Strategic Energy, LLC
Tenaska Power Services Company
The Energy Authority, Inc.
UBS Investment Bank
Westar Energy, Inc.
Williams Power Company, Inc.
Wisconsin Electric Power Company
Wisconsin Public Power Inc.
WPS Resources Corporation



# KEY FUNCTIONS AND CORE RESPONSIBILITIES

The Midwest Independent Transmission System Operator is a nonprofit organization that manages the reliable flow of electricity across much of the Midwestern United States.

Formed by its member Transmission Owners in 1996, the Midwest ISO's mission is to implement the Federal Energy Regulatory Commission's (FERC) vision of an unbiased Regional Transmission Organization (RTO) managing the regional flow of electricity. Based in Carmel, Indiana, the Midwest ISO monitors the electric transmission system between generating plants and wholesale power transmitters. As the electric power industry makes the transition to a competitive environment, the Midwest ISO's role is to ensure fair access to the transmission system and to maintain electric system reliability in the Midwest.

In its role as an RTO, it is the duty of the Midwest ISO to direct traffic on the wholesale bulk electric power lines. The Midwest ISO manages the use of the lines to ensure they don't become congested, a situation that could prompt blackouts across one or more states.

The Midwest ISO's main responsibility and commitment is to ensure the safe, reliable transfer of power in the Midwest and to eliminate rate pancaking, or the stacking of transmission rates as power moves along lines owned by different entities.

*As the electric power industry makes the transition to a competitive environment, the Midwest ISO's role is to ensure fair access to the transmission system and to maintain electric system reliability in the Midwest.*

## FUNCTIONS OF THE MIDWEST ISO

### Security and Maintenance Coordination

The Midwest ISO hub of operations is the Integrated Control Center Systems (ICCS), which allows for real-time administration of bulk electric system activity and analyzes forecasted and actual system conditions. A team of experienced operators is always on duty in the control room to ensure safe, reliable operation.

The Midwest ISO also performs regional facility maintenance coordination to identify proposed maintenance that would create adverse system conditions and works with the transmission line owners to provide remedial steps to be taken in advance of such proposed maintenance.

### Long-Term Regional Planning

By evaluating the needs of several states, the Midwest ISO is able to plan for the region's electric infrastructure in a unified, cost-effective and environmentally responsible manner.

### Scheduling

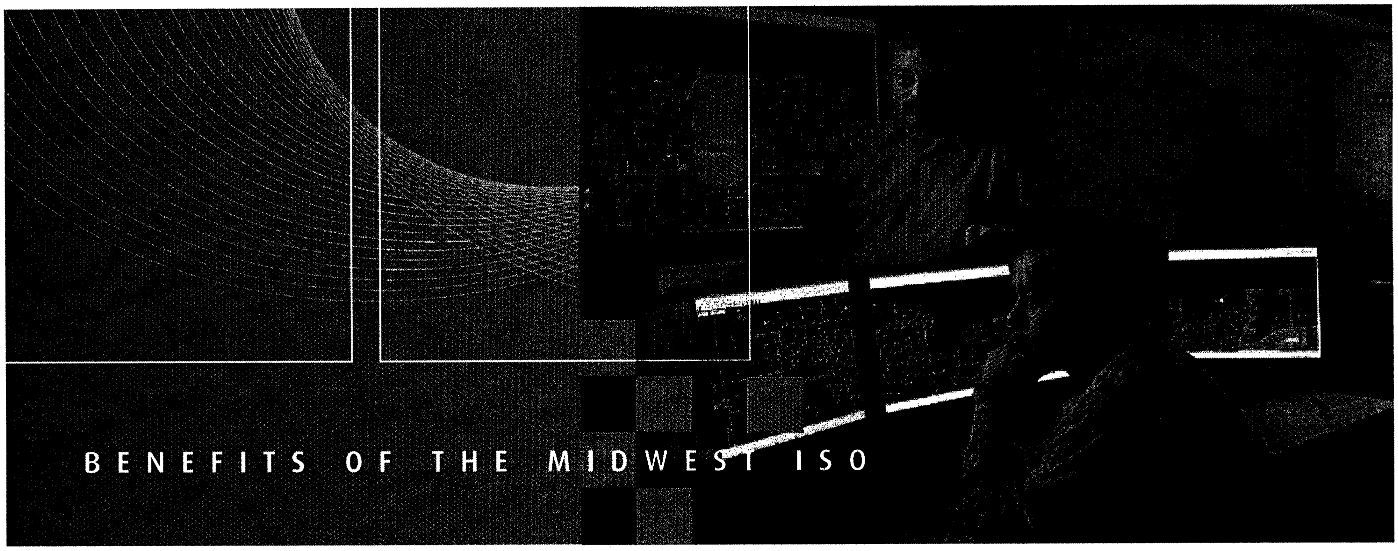
The Midwest ISO scheduling coordinators serve as the liaison between the buyer and seller in power transactions. If the delivery of the purchased power does not cause congestion in the transmission system, the transaction is approved. If there is a problem, alternatives are found for safe, reliable exchanges of electricity.

### Congestion Management

A key role for an RTO is to develop mechanisms that manage congestion in the transmission system. The mechanism selected by the RTO must provide all transmission customers with efficient pricing signals regarding the consequences of their transmission use.

### Market Monitoring

In accordance with FERC guidelines, the Midwest ISO has contracted with an independent third party to monitor the behavior of regional Market Participants, including non-RTO Transmission Owners. The Independent Market Monitor must make reports to FERC and the Midwest ISO Board of Directors.




# Explanation of Benefits — Regional Electric Transmission System Operation

## SYSTEM RELIABILITY

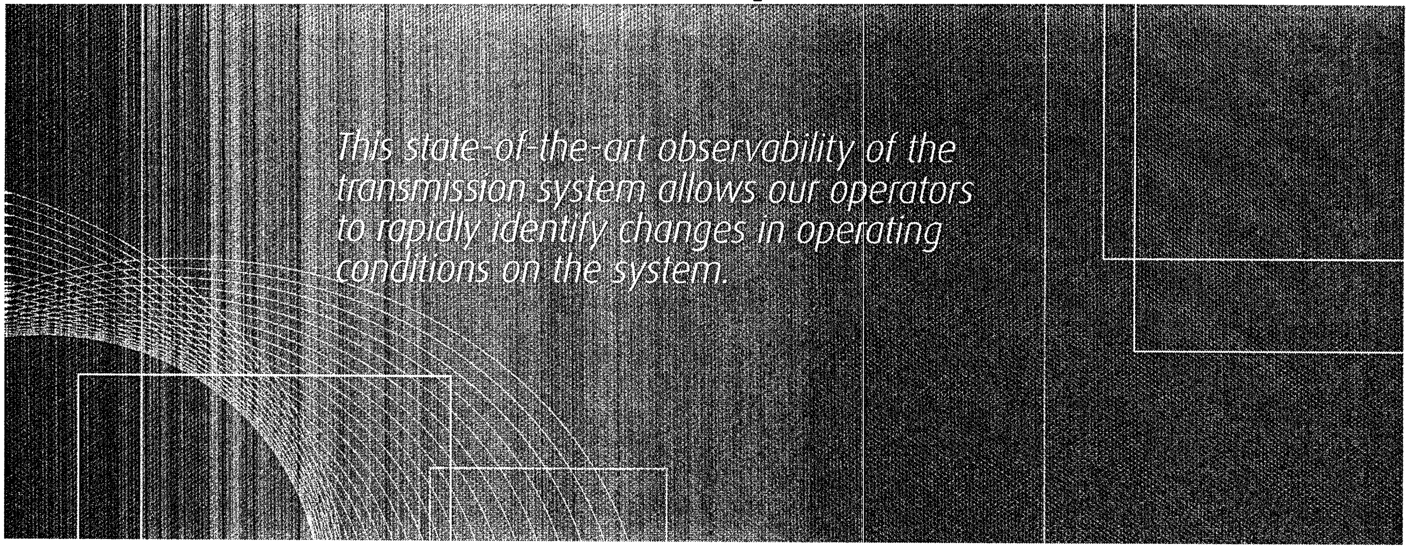
### State-of-the-Art Observability of Member Transmission Systems

The Midwest ISO has developed a series of tools designed for the Real-Time observability of its region – which spans 15 states and includes the Canadian province of Manitoba, and 1.1 million square miles – and parts of adjacent systems. These tools monitor all transmission lines and transformers over 100 kV, as well as all others identified as critical to system operations. Data from more than 96,000 data points along the grid is fed into the "State Estimator" – named because it provides operators with the current state of conditions on the power grid – which gives control room operators a detailed update of the entire system every 90 seconds.

This state-of-the-art observability of the transmission system allows our operators to rapidly identify changes in operating conditions on the system. The State Estimator then provides the information to quickly determine whether the new operating conditions require action to assure the ongoing reliability of the transmission grid.

### Assessment of Potential System Contingencies

Data from the State Estimator is modeled to develop a series of contingency analyses for potential events that could compromise system reliability. The Contingency Analysis Tool runs more than 5,000 different potential contingencies every eight minutes. As a result, control room operators are equipped with a comprehensive, big-picture look at the evolving condition of the grid on a Real-Time basis, enabling them to pinpoint potential problem areas, and take appropriate action to maintain reliability. Both the State Estimator and the Contingency Analysis tool are premier reliability systems within the transmission industry.




### Open and Transparent Transmission Congestion Management Process

As outlined in the Energy Markets Tariff filed with the FERC, security-constrained economic dispatch will optimize the use of generation resources throughout the entire Midwest ISO region without requiring market participants to engage in short-term bilateral transactions.

The Midwest Energy Markets, featuring Locational Marginal Pricing (LMP), assure that load-serving entities located inside the market can purchase or sell Real-Time or Day-Ahead energy at the most competitive price offered. Load serving-entities outside the boundary of the LMP market will not have this opportunity and will continue to incur transaction and opportunity costs associated with maintaining a sub-optimal mix of generation, purchases and sales.

Specifically, the proposed centralized dispatching of generation within the Midwest Energy Markets will enhance each of the following:

- Transaction Timing: Midwest Energy Markets will optimize the operation of generation assets across member systems through its re-dispatching capability, which will occur at least every five minutes in support of system reliability. Existing scheduling procedures limit market participants to transactions of one hour or longer.

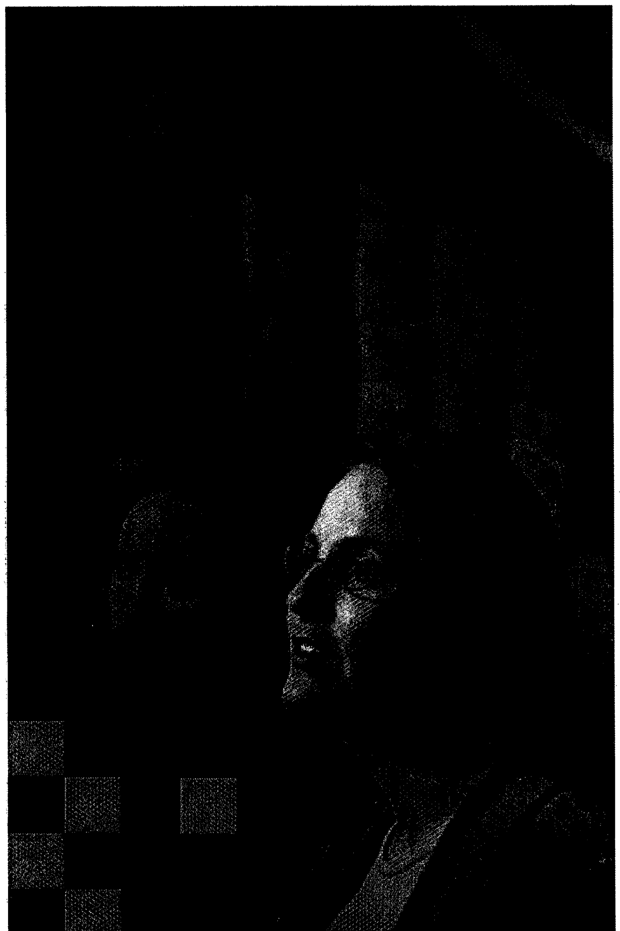
- Transaction Cost: Centralized dispatch will preempt the costly negotiation and assessment of transaction alternatives, helping achieve optimal sales and purchase mixes. Under centralized dispatch, costs related to the search for cost-effective transactions, contracting, scheduling, settlement, managing risk, and dispute resolution will be displaced.

- Data Disclosure: Data visibility enables all parties to capture available transaction opportunities in an expedited manner. Without visibility, operating incentives can fail to mitigate and in some instances even exacerbate congestion on the system. Locational Marginal Pricing discloses emerging congestion and enables market participants to select alternative purchasing opportunities, which ultimately relieves congestion, maintains system operation and sustains reliability.

### Comprehensive Coordination with Adjacent Transmission Systems

By definition, combining individual transmission systems into one large RTO dramatically reduces the number of seams issues and facilitates efficient operation of the transmission system throughout the region. With respect to the remaining seams, the Midwest ISO is aggressively pursuing arrangements to better coordinate with bordering entities. For example, the Joint Operating Agreement (JOA) between PJM and the Midwest ISO calls for unprecedented operational data exchange, as well as the sharing of information regarding emergency protocols, system planning and market monitoring. This agreement is a model for such arrangements within the industry.

This coordination reduces the risk normally associated with border areas. These areas have traditionally been viewed as at-risk due to questions about visibility and accountability. Agreements like the JOA with PJM are reducing that risk by increasing the visibility of these areas, and clarifying authority and responsibility.



Centralized economic dispatch permits the coordination of resources throughout the Midwest ISO system to meet demand requirements at the lowest possible production cost.

### Regional Solutions for Transmission and Generation Outage Planning

The sheer size of the Midwest ISO region allows for a wide view of outage planning and the potential effects of these outages. With data sharing agreements such as the JOA, we are now able to better understand the impact outages can have upon adjacent systems.

Traditionally, outage planning and coordination has been performed between Control Areas. The result has been inconsistent coordination practices. Reliability is enhanced by the Midwest ISO's provision of a well-coordinated, wide-area view of outage coordination that addresses far more contingencies than were traditionally manageable.

### Replacement of Transmission Load Relief (TLR) Procedures

Real-Time, security constrained, economic dispatch throughout the region will replace the current system of managing congestion that occurs when the transmission system cannot accommodate all transmission service requests.

Under the current system, congestion is managed through reservations of estimated Available Flowgate Capacity (AFC) and the North American Electric Reliability Council's (NERC) Transmission Loading Relief (TLR) procedures.

Replacing today's physical rationing mechanism with Real-Time, security constrained, economic dispatch will put an end to the following:

- Manual TLR procedures that result in under-utilization of transmission capacity when the demand for transmission capacity is high.
- Inherently conservative and imprecise estimates of AFC that often prevent market participants from reserving and scheduling the full capacity of the transmission system.

## COMMERCIAL BENEFITS

### Open, Non-Discriminatory Access to Transmission Facilities

As an independent evaluator and administrator of transmission service requests, the Midwest ISO uses standard business rules and a single tariff for evaluating all requests. Independent management maintains equitable access for all transmission service requests.

### Power Cost Reductions Through Centralized Dispatch

Centralized economic dispatch permits the coordination of resources throughout the Midwest ISO system to meet demand requirements at the lowest possible production cost. Economies are gained through load diversity of combined systems, reduced operating costs per unit of output of larger units, and more extensive use of lower cost generations available anywhere in the Midwest ISO system.

### Transparent Energy Markets Provide Additional Options to Reduce Costs and Manage Price Risk

Real-Time and Day-Ahead energy markets provide a transparent and liquid wholesale spot market that reveals the value of power at each of 30,000 commercially significant locations within the transmission system. In addition, the development of a transparent regional spot market will expand trading opportunities and help members optimize power purchases and sales.

Markets present the following additional opportunities to participants:

- Location-specific prices that can help identify where it may be most cost-effective to construct new generation and transmission capacity.
- Benchmarking utility fuel and operating costs against location-specific spot prices.
- Use of price signals to improve management of maintenance and outage scheduling.

LMP-based centralized dispatch facilitates the development of financial instruments that are based on and settle against the spot price. These instruments can be used to replace traditional physical contracts. Because they are more fungible and defined only in terms of price they tend to foster improved liquidity and, as a result, create an opportunity for participants to more efficiently manage their energy price risk.

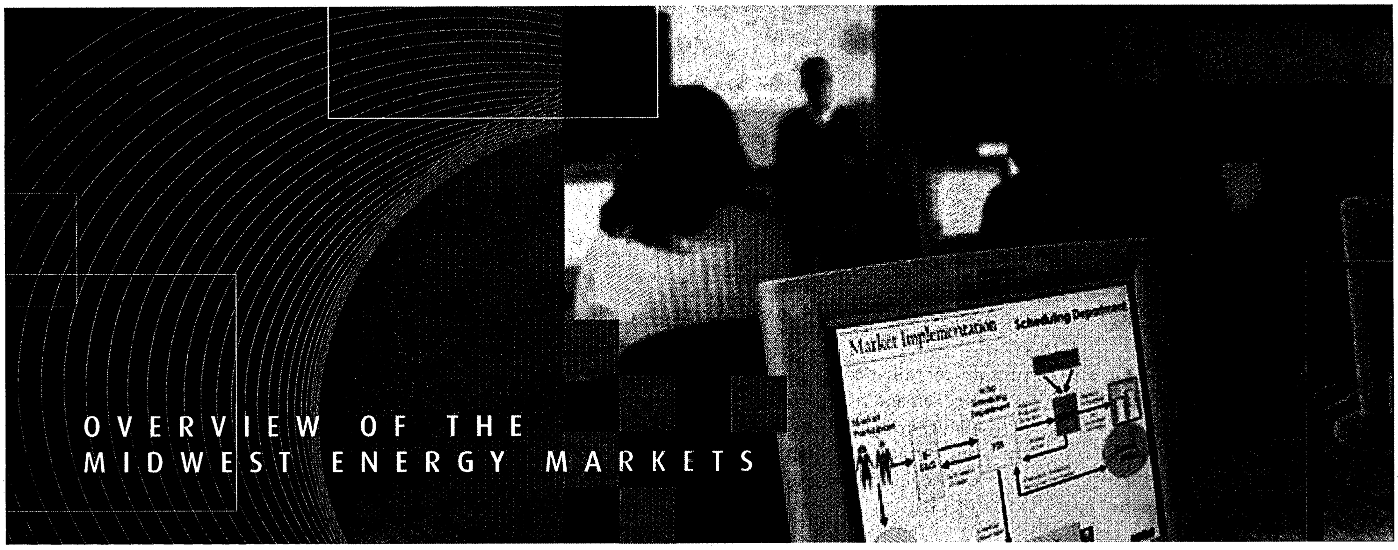
### Regionally Coordinated, Cost-Effective Planning of Transmission Expansion

Regionally coordinated transmission expansion planning benefits the region by providing expansion decisions that are more cost-effective and reliability centered than would be produced by sub-regional planning. Control Area regional planning typically results in expansion decisions that are optimized for individual Control Areas, not for the region as a whole. Neighboring Control Area plans, each optimized for their individual Control Area, are unlikely to provide the optimal plan for the combined area. The benefit of regionally coordinated planning is to provide regional optimization.

The scope of the Midwest ISO allows for an unparalleled level of comprehensive transmission planning. We are able to analyze the effects of cross-transmission border impacts, which enables the selection of siting locations for optimal system expansion to support reliability and cost-effectiveness. The JOA between the Midwest ISO and PJM extends this same concept across our common border, and the Midwest ISO is working to expand that concept to other borders as well.

### Single OASIS Site to Support Transmission Access

The Midwest ISO provides a single, centralized OASIS site, eliminating the need for our members to develop and maintain individual sites to sell transmission service. This also eliminates the need for transmission customers to piece together transmission service from several OASIS sites in order to complete a transaction across the Midwest ISO region. This benefits members by reducing their costs to develop and maintain a site, and also by reducing their costs of transmission services over multiple transmission systems.



# OVERVIEW OF THE MIDWEST ENERGY MARKETS

With the launch of the Midwest Energy Markets in April 2005, the Midwest ISO will take on another significant role in addition to its core function as Reliability Coordinator for the region.

Energy Markets will make more efficient use of the generating facilities and transmission services within the organization's territory and along its borders.

Importantly, Energy Markets also will result in much greater transparency regarding the dispatch and transmission of power within the Midwest region, which should put downward pressure on energy prices, increase the number of transactions – and at the same time considerably improve management of congestion along the grid.

### Energy Markets Tariff

In keeping with the Federal Energy Regulatory Commission's (FERC) Order No. 2000 requiring Regional Transmission Organizations (RTOs) to provide Real-Time energy imbalance services and a market-based mechanism for congestion management, the Midwest ISO filed its Energy Markets Tariff with FERC in the spring of 2004. In August 2004, FERC conditionally approved the tariff, which sets out the rates, terms and conditions necessary to implement a platform featuring the centralized dispatch of generation resources throughout much of the Midwest.

The Midwest ISO's security-constrained economic dispatch platform is supported by a Day-Ahead and Real-Time Energy Market design, including Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) within the region.

### What is Changing?

Beginning in April 2005, the Midwest ISO will be responsible for operating both Day-Ahead and Real-Time Energy Markets to arrive at an optimal dispatch solution for all resources within the region. This will enable the Midwest ISO to ensure that all load requirements in the region are met reliably and efficiently. Local Control Area Operators will continue to be responsible for many of the traditional Control Area operations, but will operate their systems in response to price signals issued by the Midwest ISO.

With the operation of the Midwest Energy Markets, the Midwest ISO will operate one of the largest LMP-based Energy Markets in the world. Open, transparent Energy Markets will improve congestion management along the grid and produce real and measurable benefits for the more than 15 million electricity customers residing in the Midwest ISO's territory.

### Benefits of Energy Markets

In 2004, at FERC's request, the Midwest ISO conducted an analysis of projected cost savings expected to result from the operation of regional, security-constrained economic dispatch and Real-Time and Day-Ahead Energy Markets featuring Locational Marginal Pricing. This analysis concluded that implementation of the Midwest Energy Markets would not only lower spot energy prices, but put downward pressure on prices in bilateral contracts, resulting in a potential annual gross savings of about $713 million to Midwest energy consumers.

*Open, transparent Energy Markets will improve congestion management along the grid and produce real and measurable benefits for the more than 15 million electricity customers residing in the Midwest ISO's territory.*

## SIGNIFICANT MILESTONES

### Systems Operations Tests

During the month of December 2004, the Midwest ISO completed the first two of several Systems Operations tests to demonstrate the organization's ability to dispatch generation.

### System Restoration Drills

The Midwest ISO also completed two scheduled System Restoration Drills to show how the Midwest ISO and other Market Participants would communicate in the event of a power grid emergency. The North American Electric Reliability Council (NERC) also participated in these simulated drills.

### Allocation of Financial Transmission Rights (FTRs)

The Midwest ISO allocated four tiers of Financial Transmission Rights (FTR), worth an estimated half billion to one billion dollars, to hedge against the potential costs of congestion. These allocations enabled Market Participants to make financially binding decisions that will settle when the Day-Ahead and Real-Time Energy Markets open on April 1, 2005.

### Parallel Operations I and II

During Parallel Operations, Midwest ISO control room operators simulated a true market environment to train and practice for live market operations. Parallel Operations II included more enhanced testing that incorporated Grandfathered Agreement enhancements and the final Energy Market Tariff changes required by FERC.

### Financial Trading Hubs

The Midwest ISO has created four financial trading hubs in support of the launch of its Midwest Energy Markets. The Midwest ISO hubs – Minnesota, Cinergy, Michigan and Illinois – provide participants common pricing points from which to contract or trade and should reduce uncertainty for parties who wish to contract. The hubs also should improve liquidity and facilitate wholesale market sales and purchases of electricity, allowing for the development of a more robust wholesale electricity market.

### North American Electric Reliability Council (NERC) audit of Joint Operating Agreement functionality

NERC's Interchange Distribution Calculator Working Group issued a favorable report on the Midwest ISO's market flow calculator, finding the successful calculation of market flow and transfer of data. The calculator modifications allow Midwest ISO operators to upload market flow information to NERC, ensuring smooth operations for the Midwest ISO Energy Markets should a Transmission Loading Relief event be called to relieve system congestion.

### Completion of Final Trials

Testing of all functionality identified in the Energy Markets Tariff and the Grandfathered Agreement Orders was completed during final trials held in January and February. The implementation of the Midwest ISO system cutover plan for ongoing market operations began on March 19.

# REPORT OF INDEPENDENT AUDITORS

## To the Board of Directors of Midwest Independent Transmission System Operator, Inc.:

In our opinion, the accompanying balance sheet and the related statements of operations and changes in net assets and of cash flows present fairly, in all material respects, the financial position of Midwest Independent Transmission System Operator, Inc. at December 31, 2004 and 2003, and the results of the changes in its net assets and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

February 7, 2005

**MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.**
**BALANCE SHEET**
AS OF DECEMBER 31 *(Dollar amounts in thousands)*

| ASSETS | 2004 | 2003 |
|---|---|---|
| **Current Assets:** | | |
| Cash and Cash Equivalents | $ 54,042 | $ 12,805 |
| Restricted Cash | 52,051 | 28,989 |
| Deposits | 6,079 | 5,489 |
| Accounts Receivable (Note 5) | 13,021 | 12,101 |
| Accounts receivable-related party (not used after 6/01) | - | - |
| Deferred Regulatory Assets (Note 4) | 34,051 | 26,448 |
| Prepayments | 6,591 | 6,375 |
| **Total Current Assets** | 165,835 | 92,207 |
| **Fixed Assets:** | | |
| Fixed Assets (Note 6) | 155,794 | 133,772 |
| Accumulated Depreciation and Amortization | (57,739) | (35,781) |
| | 98,055 | 97,991 |
| Projects in Development | 162,581 | 85,766 |
| Net Fixed Assets | 260,636 | 183,757 |
| **Other Assets:** | | |
| Deferred Note Offering Fee | 3,583 | 1,199 |
| Deferred Regulatory Assets (Note 4) | 140,686 | 94,133 |
| Total Assets | $ 570,740 | $ 371,296 |
| **LIABILITIES AND NET ASSETS** | | |
| **Current Liabilities:** | | |
| Accounts Payable | $ 14,387 | $ 14,750 |
| Accrued Liabilities (Note 7) | 31,485 | 21,198 |
| Accrued Interest | 5,871 | 2,356 |
| Restricted Deposits | 41,429 | 26,579 |
| FERC Assessment Liability (Note 4) | 6,511 | 16,712 |
| Line of Credit (Note 11) | - | 5,000 |
| Current Portion of Capitalized Leases (Note 10) | 5,420 | 3,533 |
| Reserve for Disputed Amounts | 3,656 | - |
| Notes Payable (Note 12) | 99 | 124 |
| Deferred Revenue | 785 | 807 |
| Total Current Liabilities | 109,643 | 91,059 |
| **Long-Term Liabilities:** | | |
| Accrued Liabilities | 1,434 | 1,749 |
| Capitalized Leases, Net of Current Portion (Note 10) | 17,891 | 18,426 |
| Deferred Revenue | 35,195 | 59,631 |
| Notes Payable (Note 12) | 1,871 | 764 |
| Notes Payable, Net of Unamortized Discount (Note 12) | 404,706 | 199,667 |
| Total Long-Term Liabilities | 461,097 | 280,237 |
| **Net Assets** | | |
| Total Liabilities and Net Assets | $ 570,740 | $ 371,296 |

***The accompanying notes are an integral part of these financial statements***

**MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.**
**STATEMENT OF OPERATIONS AND CHANGES IN NET ASSETS**
FOR THE PERIOD ENDED DECEMBER 31 *(Dollar amounts in thousands)*

| | 2004 | 2003 |
|---|---|---|
| **Revenues** | | |
| Cost Recovery Adder | $ 117,249 | $ 66,978 |
| Memberships & Dues | 191 | 169 |
| FERC Assessment | 25,851 | 5,510 |
| Contract Revenue | 5,571 | 5,874 |
| Engineering Studies Income | 2,863 | 2,308 |
| Grant Revenue | 493 | 1,000 |
| Other | 1,082 | 1,586 |
| Total Revenues | 153,300 | 83,425 |
| **General and Administrative Expenses** | | |
| Salaries and Benefits | 53,504 | 35,776 |
| Depreciation and Amortization | 24,214 | 19,985 |
| Outside Services | 45,949 | 23,450 |
| Occupancy/Telecommunications | 12,717 | 10,675 |
| Insurance | 3,207 | 1,966 |
| FERC Assessment (Note 4) | 19,798 | 18,088 |
| Computer Maintenance | 8,462 | 4,086 |
| Other | 8,458 | 5,747 |
| Total General and Administrative Expenses | 176,309 | 119,773 |
| **Other Income (Expense):** | | |
| Interest Income | 1,496 | 925 |
| Interest Expense | (17,694) | (12,169) |
| Other Income (Expense) | 874 | (1) |
| Total Other Income (Expense) | (15,324) | (11,245) |
| **Deferral of Regulatory Asset, Net** | 38,333 | 47,593 |
| **Change in Net Assets** | $ - | $ - |

*The accompanying notes are an integral part of these financial statements*

**MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.**
**STATEMENT OF CASH FLOWS**
FOR THE PERIOD ENDED DECEMBER 31 *(Dollar amounts in thousands)*

| | 2004 | 2003 |
|---|---|---|
| **Cash Flows from Operating Activities:** | | |
| Change in Net Assets | $ - | $ - |
| Adjustments to reconcile Change in Net Assets to Net Cash and Cash Equivalents Used in Operating Activities: | | |
| Depreciation and Amortization | 24,214 | 19,985 |
| Gain on Extinguishment of Debt | (878) | - |
| Deferral of Regulatory Asset, Net | (38,333) | (47,593) |
| New Member Payments (Note 4) | (15,823) | (23,174) |
| Deferred Revenue | (24,458) | (230) |
| *Increase in Operating Assets -* | | |
| Restricted Cash | (23,061) | (19,547) |
| Deposits | (589) | (2,480) |
| Accounts Receivable | (920) | (3,400) |
| Prepayments | (216) | (4,156) |
| *Increase (Decrease) in Operating Liabilities -* | | |
| Accounts Payable | (363) | 8,234 |
| Accrued Liabilities | 9,972 | 14,235 |
| Restricted Deposits | 14,850 | 17,257 |
| Accrued Interest | 3,515 | 1,506 |
| FERC Assessment Fee Accrual | (10,201) | 16,712 |
| Reserve for Disputed Amounts | 3,656 | (1,943) |
| Net Cash and Cash Equivalents Used In Operating Activities | (58,635) | (24,594) |
| **Cash Flows from Investing Activities** | | |
| Disposal of Assets | 6 | - |
| Capital Expenditures | (95,431) | (82,834) |
| Net Cash and Cash Equivalents Used in Investing Activities | (95,425) | (82,834) |
| **Cash Flows from Financing Activities:** | | |
| Net proceeds (payments) on line of credit | (5,000) | 5,000 |
| Payments on Notes and Capital Leases | (3,939) | (3,150) |
| Proceeds from Notes | 207,000 | 100,000 |
| Note Offering Fees | (2,764) | (787) |
| Net Cash and Cash Equivalents Provided by Financing Activities | 195,297 | 101,063 |
| **Net Increase/(Decrease) in Cash and Cash Equivalents** | 41,237 | (6,365) |
| **Cash and Cash Equivalents, beginning of period** | 12,805 | 19,170 |
| **Cash and Cash Equivalents, end of period** | $ 54,042 | $ 12,805 |
| **Supplemental Cash Flow Information:** | | |
| Cash paid during the period for interest | $ 14,179 | $ 13,050 |

*The accompanying notes are an integral part of these financial statements*

# NOTES TO FINANCIAL STATEMENTS

(Dollar amounts in thousands)
December 31, 2004

## 1. ORGANIZATION AND SIGNIFICANT DEVELOPMENTS

On December 19, 2001 the Midwest Independent Transmission System Operator, Inc. (Midwest ISO or the Company) became the nation's first Regional Transmission Organization (RTO) approved by the Federal Energy Regulatory Commission (FERC). As an RTO, the Midwest ISO provides transmission service on behalf of its members who own transmission assets. In addition, the Midwest ISO is a North American Electric Reliability Council certified reliability coordinator. In that capacity, the Midwest ISO monitors the flow of electricity over the transmission systems of its members who own transmission assets.

The Midwest ISO was incorporated as a Delaware non-stock non-profit corporation in March 1998. The Company is governed by an independent Board of Directors. Membership in the Midwest ISO is open to owners of electric transmission facilities as well as other participants in the electric energy market. Twenty-seven transmission owners with more than 97,000 miles of transmission lines, 131,000 megawatts of electric generation, and approximately $11.8 billion in installed gross transmission assets are currently participating in the Midwest ISO.

On December 15, 2001, the Company began providing reliability coordination services to the transmission-owning members of the Midwest ISO and their customers. On the same date, the Midwest ISO also began providing operations planning, generation interconnection, maintenance coordination, long-term regional planning, market monitoring and dispute resolution services. The Company commenced substantially all operations on February 1, 2002, the date the Midwest ISO began providing regional transmission service under its FERC-accepted Open Access Transmission Tariff (the Tariff).

In the December 19, 2001 order granting the Midwest ISO RTO status, FERC directed the Midwest ISO to implement its proposed market-based, congestion management system in a timely manner. FERC re-affirmed this directive in its July 31, 2002 order conditionally accepting the elections of the former Alliance RTO members to join either the Midwest ISO or PJM Interconnection, LLC. (PJM). The Midwest ISO's proposal to implement a market-based, congestion management system includes the development and operation of the following:

- Day-Ahead energy market
- Real-Time energy market
- Financial Transmission Rights (FTR) market

The Day-Ahead and Real-Time energy markets will price transmission system congestion through the use of Locational Marginal Pricing (LMP) algorithms. FTRs provide a means of hedging LMP-based congestion costs. The Midwest ISO anticipates expending approximately $158.1 million in capital and $85.9 million of deferred operating costs for a total to complete the development of the systems of $244.0 million to implement these markets with a planned operation date of March 1, 2005.

The July 31, 2002 FERC order also directed the Midwest ISO and PJM to develop a common market by October 1, 2004. Subsequent to the FERC order, the Midwest ISO and PJM requested an extension of time to implement the common market to September 1, 2007.

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### Basis of Presentation

The accompanying financial statements have been prepared in accordance with generally accepted accounting principles.

### Regulation

The Midwest ISO is subject to regulation by FERC. The Midwest ISO accounts for the effects of regulation in its financial statements in accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). This statement sets forth the application of generally accepted accounting principles for those companies whose rates are established by or are subject to approval by an independent third-party regulator. Under SFAS No. 71, regulated companies defer costs and credits on the balance sheet as regulatory assets and liabilities when it is probable that those costs and credits will be recognized in the rate setting process in a period different from the period in which they would have been reflected in income and expense by an unregulated company. These deferred regulatory assets and liabilities are then reflected in the statement of operations in the period in which the same amounts are reflected in rates charged for service.

### Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

### Cash and Cash Equivalents

The Company considers all highly liquid investment instruments purchased with a maturity of three months or less to be cash equivalents.

Under the Tariff, customers that request a generation interconnection or facility upgrade study must pay the costs incurred to perform an impact assessment study. Further, a deposit is required before the study is undertaken. At December 31, 2004 and 2003, the deposits balance was comprised of $6,061 for generation interconnection studies and $5,433 for facility upgrade studies, respectively. An offsetting liability equal to the deposit balance is recorded on the balance sheet in current accrued liabilities. As expenses are incurred, revenue is recognized and deducted from the deposits for services performed by the Midwest ISO for these impact assessment studies. Also included in the deposits balance are security deposits for leased space; the balance was $18 at December 31, 2004, and $56 at December 31, 2003.

Restricted cash consists of funds restricted for interest payments on the 2013 Notes, 2014 Notes, and 2009 Notes plus deposits from customers who provide cash collateral as a form of financial assurance to secure the customer's performance under the terms and conditions of the Midwest ISO's Tariff related to the purchase of transmission service, ancillary services and related products or services. Interest earned on the deposits is paid to the customer semi-annually on January 31st and July 31st of each year. At December 31, 2004 and 2003, $41,776 and $26,666, respectively, was held in security for customer deposits, which includes interest payable of $346 and $87. Restricted cash also includes funds held for the note interest payments in the amount of $6,619 and $2,323, respectively. The remainder of the restricted cash balance includes funds held in escrow for a dispute filed by one transmission owner which is currently in arbitration. This balance is $3,656 as of December 31, 2004.

The Midwest ISO is obligated to return any portion of the financial assurance deposit upon request of the customer to the extent that the amount exceeds the customer's total potential financial exposure for services purchased from the Midwest ISO.

### Concentration of Credit Risk

Financial instruments that subject the company to credit risk consist primarily of accounts receivable and uninsured cash balances. The organization maintained cash balances in excess of insured Federal Deposit Insurance Corporation limits at December 31, 2004, and from time to time during the period from inception through December 31, 2004. No allowance has been recorded for accounts receivable at December 31, 2004, as management considers all accounts receivable to be probable of collection. Customers are required to conduct business subject to approved credit limits and to post financial assurances if the Midwest ISO elects not to extend unsecured credit to the customer.

### Fair Value of Financial Instruments

The carrying values reported in the balance sheet for current assets, current liabilities, and capital leases approximate their fair values. Management has estimated the value of the 2012 Notes payable to be approximately $123,560 and $119,744 based on the trading price of similarly rated notes at December 31, 2004 and 2003, respectively. Management has estimated the value of the 2013 Notes payable to be approximately $100,770 and $98,933 based on the trading price of similarly rated notes at December 31, 2004 and December 31, 2003, respectively. Management has estimated the value of the 2014 Notes payable to be approximately $99,430 based on the trading price of similarly rated notes at December 31, 2004. Management has estimated the value of the 2009 Notes payable to be approximately $96,240 based on the trading price of similarly rated notes at December 31, 2004.

### Fixed Assets

Fixed assets, consisting primarily of telecommunications equipment, computer equipment, software, leasehold improvements, and furniture and fixtures, are recorded at cost and are depreciated on a straight-line basis over the estimated useful lives of the assets. The major classes and lives include: buildings and improvements, 20 years; computer hardware, 6 years; computer software, 7 years; furniture and fixtures, 7 years; and telecommunications equipment, 7 years. Cost consists of materials and supplies, labor, related taxes and capitalized interest. The depreciation policy for leaseholds is the shorter of the life of the asset or the term of the lease. Maintenance and repair costs are charged to expense when incurred. The costs incurred to acquire and develop computer software for internal use, including financing costs, are capitalized. Costs incurred prior to the determination of feasibility of developed software and following the in-service date of developed software are expensed.

To comply with FERC's December 19, 2001 order to implement its proposed market-based, congestion management services, the Midwest

ISO began expending funds in April 2002 to develop the systems needed to provide these services. During the year ended December 31, 2004, the Midwest ISO expended $74,332 in capital expenditures on the market systems. As of December 31, 2003, the Midwest ISO had capital expenditures of $72,833 bringing the total capital project cost to date to $147,165. During 2004 and 2003, $4,629 and $2,063 of interest, respectively, was capitalized and included in Projects in Development.

### Revenue Recognition

Pursuant to the Midwest ISO's FERC-accepted Tariff, the Midwest ISO recognizes as revenue amounts both billed and unbilled for which the Midwest ISO has incurred costs as of the period end. The Schedule 10 – Cost Recovery Adder of the Tariff provides for recovery of all costs, including capital and operating expenses, of the Midwest ISO. The Midwest ISO also recognizes as revenue amounts billed to participants for initial membership, training, and annual dues. In addition, the Midwest ISO recognized $5,571 and $5,874 in revenue for services provided to MAPPCOR Inc. (MAPPCOR) during 2004 and 2003, respectively. The Midwest ISO bills MAPPCOR for services rendered based on monthly estimated expenses. The Midwest ISO also recognizes revenue and an offsetting expense for the annual FERC Assessment Fee. The annual fee is assessed on the MWhs of transmission usage for each transmission provider as reported on form FERC 582. Per the terms of its Tariff, the Midwest ISO recovers from its transmission customers their proportionate share of the FERC Assessment Fee based on their individual MWhs of transmission usage as reported on form FERC 582. FERC invoices transmission providers in August of each year and payment is due in September. The Company accrues each month revenue and an offsetting expense equal to one twelfth of the estimated fee for the appropriate fiscal year based on the most recent year's MWhs of transmission usage by its customers.

The Midwest ISO also performs engineering studies on behalf of its customers. The Midwest ISO is reimbursed for its costs of performing the studies. The amount of $2,863 was recognized as revenue from engineering studies for year ended December 31, 2004 and $2,308 was recognized as of December 31, 2003.

The Midwest ISO fulfilled all the requirements to receive certain Grants from the State of Indiana. During the year ended 2004, the Midwest ISO applied to receive economic incentives from Indiana for the creation of new jobs in the State of Indiana. In 2004 the Midwest ISO applied to receive $493 for employees hired during 2003. In 2003 the Midwest ISO applied to receive $300 for employees hired during 2002. Also during 2003, the Midwest ISO was successful in fulfilling the requirements of the Indiana Economic Development Grant, which amounted to $500. Also, during 2003, the Midwest ISO fulfilled the requirements of the Indiana Skills Enhancement Grant, which amounted to $200. This revenue is recorded as Grant Revenue.

During 2004, Ameren and Illinois Power rejoined the Midwest ISO. Pursuant to the terms of a FERC order, the Midwest ISO returned to Ameren and Illinois Power $24,382 in total, which was their share of a $60,000 exit fee paid by Ameren, Commonwealth Edison and Illinois Power as a condition of withdrawing from the Midwest ISO in 2001. The $60,000 exit fee was recorded as deferred revenue as discussed below in Note 3. The remaining balance of the original $60,000 exit fee less credits earned to date, $35,195, is recorded as deferred revenue. The Company has also recorded $784 and $807 as other deferred revenue at December 31, 2004 and 2003, respectively, which consists primarily of membership dues for 2004 and amounts billed in advance for services to be provided to MAPPCOR during the first quarter of 2005.

### Reclassifications

Certain reclassifications have been made to the 2003 presentation to conform to the 2004 presentation.

## 3. MEMBERSHIP

Effective May 8, 2001, FERC approved a settlement agreement that permitted the withdrawal of Illinois Power Company, Commonwealth Edison Company, and Ameren Services Company from the Midwest ISO to join the proposed Alliance RTO (Alliance). The three parties paid an exit fee to the Midwest ISO of $60 million on May 11, 2001 and are eligible to receive credits for transmission service up to the $60 million through December 15, 2013. During the years ended December 31, 2004 and 2003, $54 and $171 were utilized as credits, respectively.

On December 19, 2001 FERC denied Alliance RTO status and directed the Alliance companies to explore membership in the Midwest ISO. Discussions with the Alliance companies commenced in January 2002. Three of the former Alliance companies, Ameren Services Company, FirstEnergy Corporation subsidiary American Transmission Systems, Inc. (ATSI), and Northern Indiana Public Service Company (NIPSCO), formed GridAmerica and executed an agreement with the Midwest ISO to join as an Independent Transmission Company (ITC). ATSI and NIPSCO joined the Midwest ISO on October 1, 2003. May 1, 2004 Ameren joined the Midwest ISO. Upon joining, as part of the ITC Agreement with GridAmerica, the Midwest ISO returned to Ameren $18 million plus interest, which is Ameren's portion of the $60 million paid under the settlement agreement. In addition, the Midwest ISO made another $7.1 million payment to Ameren to reimburse it for expenditures made to develop Alliance RTO and to comply with the requirements of FERC Order 2000.

On September 30, 2004, Illinois Power joined the Midwest ISO. The Midwest ISO refunded Illinois Power the $6.4 million exit fee, less credits earned under Schedule 10-A of $.1 million, it paid as part of the settlement agreement with the three departing members. Other costs that were reimbursed included payments of $8.7 million to Illinois Power to reimburse it for its costs to develop the Alliance RTO and to comply with FERC Order 2000.

(Dollar amounts in thousands)

By letter dated December 31, 2004 LG&E Energy Corporation subsidiaries Louisville Gas & Electric and Kentucky Utilities ("LGE/KU") provided a notice of withdrawal to the Midwest ISO in accordance with the terms and conditions of the Midwest ISO Transmission Owners Agreement. Such a notice allows LG&E/KU to commence a process of withdrawal of its facilities from the Midwest ISO. The earliest LGE/KU could withdraw from the Midwest ISO is December 31, 2005. In order to withdraw LGE/KU must also file with the Federal Energy Regulatory Commission for permission to withdraw. As of February 10, 2005 LGE/KU had not made the requisite filing at FERC. A docketed proceeding before the Kentucky Public Service Commission on the benefits of RTO membership for the ratepayers of LGE/KU was initiated in 2003. That proceeding remained open as of February 10, 2005. If (i) the state proceeding were to approve LG&E/KU's transfer of control of its system back to itself and (ii) should LGE/KU file at FERC for permission to withdraw and (iii) should FERC grant permission to withdraw, then LGE/KU would be responsible to pay its proportionate share of the outstanding financial obligations of the Midwest ISO as required by the terms of the Midwest ISO Transmission Owners Agreement and the Midwest ISO's Open Access Transmission Tariff.

## 4. REGULATORY ASSETS

The following regulatory assets were included in "Deferred Regulatory Assets" line on the Balance Sheet:

The Midwest ISO's operating costs incurred prior to its initial start-up in December 2001 were deferred in accordance with a FERC order. These deferred costs are being recovered over a six-year period from Midwest ISO's customers through monthly charges under Schedule 10 of the Tariff. The "$0.15 per MWh Rate Cap" asset is for on-going costs incurred but not recovered under Schedule 10 due to the $0.15 per MWh rate cap in place during the first six years of commercial operations. The rate cap ends on February 1, 2008. During the year ended December 31, 2004, the Midwest ISO incurred costs not recovered under Schedule 10 in the amount of $4,541. The cumulative amount of Schedule 10 costs not yet recovered due to the rate cap was $6,173 as of the end of 2004. Costs deferred due to the rate cap are eligible for recovery every month during the balance of the six-year transition period that started February 1, 2002 and ends January 31, 2008. Per the Tariff, any outstanding balance as of February 1, 2008 not recovered due to the rate cap will be amortized and recovered over a five-year period starting February 1, 2008.

During 2003, the Midwest ISO entered into a FERC approved settlement agreement over the definition of megawatt hours of transmission service in the Schedule 10 Cost Recovery Adder. This agreement resulted in the deferral of $25 million of costs incurred during 2003. These deferred costs will be recovered over a five-year period beginning February 1, 2008.

The operating costs associated with the start-up of the Midwest Market Initiative are being deferred in accordance with a FERC order. These costs will be recovered from market participants through weekly charges under Schedules 16 and 17 of the Tariff. These Schedules will begin upon market start-up scheduled for April 1, 2005. The

| | Start-up Costs | $0.15 per MWh Rate Cap | Settlement Agreement | Market Start-up Costs | GridAmerica/ Ameren/Illinois Power Payments | Annual FERC Assessment Fee | Total |
|---|---|---|---|---|---|---|---|
| December 31, 2002 | 48,478 | 151 | | 1,185 | | | 49,814 |
| Deferral - 2003 | | 1,481 | $25,000 | 18,822 | $23,174 | $16,712 | 85,189 |
| Amortization - 2003 | (9,696) | | | | (579) | (4,147) | (14,422) |
| December 31, 2003 | 38,782 | 1,632 | 25,000 | 20,007 | 22,595 | 12,565 | 120,581 |
| Deferral - 2004 | | 4,541 | | 51,302 | 15,823 | 6,511 | 78,177 |
| Amortization - 2004 | (9,696) | | | | (3,082) | (12,565) | (25,343) |
| Interest | | | | | 1,322 | | 1,322 |
| December 31, 2004 | $29,086 | $6,173 | $25,000 | $71,309 | $36,658 | $6,511 | $174,737 |

(Dollar amounts in thousands)

amortization period for recovery of these charges based on a FERC filing made in January 2005 will be seven years. There is no cap or limit on the cost per MWh rate charged under Schedule 16 or Schedule 17 of the Tariff.

During 2003, Midwest ISO paid $23.2 million to certain participants in GridAmerica LLC to reimburse them for expenditures they made to develop the Alliance RTO and to comply with the requirements of FERC Order 2000. Pursuant to a FERC order, these costs will be recovered over a 10-year period.

Effective May 1, 2004, Ameren joined the Midwest ISO. On April 30, 2004, the Midwest ISO paid $26,075 to Ameren including $18 million to reimburse the exit fee that Ameren paid in 2001 to withdraw from the Midwest ISO and join Alliance RTO, $949 in interest on the exit fee, and $7,126 to reimburse Ameren for expenditures they made to develop Alliance RTO and to comply with the requirements of FERC Order 2000. Pursuant to a FERC order, the $7,126 and the $949 will be recovered over a 10-year period.

Effective September 30, 2004, Illinois Power joined the Midwest ISO. On October 4, 2004, the Midwest ISO paid $15,452 to Illinois Power including $6,382 to reimburse the exit fee that Illinois Power paid in 2001 to withdraw from the Midwest ISO and join Alliance RTO, $373 in interest on the exit fee, and $8,697 to reimburse Illinois Power for expenditures they made to develop Alliance RTO and to comply with the requirements of FERC Order 2000. Pursuant to a FERC order, the $8,697 and the $373 will be recovered over a 10-year period.

In September 2003, the Federal Energy Regulatory Commission assessed the Midwest ISO an annual fee based upon megawatt hours of transmission system usage by its customers. The total amount immediately due for the fiscal year October 1, 2003 through September 30, 2004 was $1,376. The filing that FERC accepted from the Midwest ISO, and used in its invoice calculation, included an understated volume of transmission service for the Midwest ISO. As a result, the Midwest ISO was billed an additional amount in 2004 that captured the total volume of transmission service during 2002. This additional amount was $12,083.

The second component of the FERC Assessment asset is the fee for FERC fiscal year October 1, 2004 through September 31, 2005 based on energy consumption during 2004. This fee will be paid in September 2005. The Midwest ISO recorded three months of this fee as an accrual during 2004 in the amount of $6,511.

Midwest ISO anticipates that all deferred start-up costs will be recovered pursuant to the Tariff by 2014. It is the opinion of management that the remaining deferred regulatory asset will be recovered through services performed in a future period and that continued application of SFAS No. 71 is appropriate.

## 5. ACCOUNTS RECEIVABLE

The Midwest ISO's receivables at December 31, 2004 and 2003 consisted of the following:

| | 2004 | 2003 |
|---|---|---|
| Billed: | | |
| Schedule 10 | $ 5 | $ 7 |
| MAPPCOR services | 596 | 493 |
| EDGE credit | 792 | 299 |
| MCN contract receivable | 184 | 257 |
| Grant receivables | | 700 |
| Employee receivable | 27 | 26 |
| FERC assessment receivable | 64 | 1,557 |
| Other receivables | 171 | 0 |
| | 1,839 | 3,339 |
| Unbilled: | | |
| Schedule 10 | 11,182 | 8,762 |
| | $13,021 | $12,101 |

## 6. FIXED ASSETS

Fixed assets at December 31, 2004 and 2003, consists of the following:

| | 2004 | 2003 |
|---|---|---|
| Land | $ 2,158 | $ 2,158 |
| Buildings and improvements | 30,228 | 24,631 |
| Computer hardware, software | 106,936 | 93,218 |
| Furniture and fixtures | 2,944 | 2,877 |
| Telecommunication equipment | 13,528 | 10,888 |
| | 155,794 | 133,772 |
| Less: accumulated depreciation and amortization | (57,739) | (35,781) |
| | $ 98,055 | $ 97,991 |

The Company abandoned several assets during the year ended 2004 and changed the useful life estimate to fully depreciate the assets. The net book value of the assets abandoned during 2004 was $948.

The Company is also planning on reviewing assets in service on April 1, 2005 to determine if all assets will be used and useful going forward after the FTR and energy markets open and anticipates recording additional abandonments in 2005.

(Dollar amounts in thousands)

## 7. CURRENT ACCRUED LIABILITIES

As of December 31, 2004 and 2003, the Midwest ISO had current accrued liabilities recorded of $31,485 and $21,198. The following table provides the major components of the period end December 31, 2004 and 2003 balances:

| | 2004 | 2003 |
|---|---|---|
| Engineering study deposits | $ 6,089 | $ 5,433 |
| Employee benefits | 6,249 | 4,428 |
| Property taxes | 1,042 | 697 |
| Employee vacation | 1,018 | 665 |
| Member reimbursements | 6,558 | 2,802 |
| Other operating/capital accrued liabilities | 10,529 | 7,173 |
| Total | $31,485 | $21,198 |

## 8. RETIREMENT PLANS

The Company established effective August 1, 1999, a defined contribution 401(k) retirement plan, which covers all full-time employees as of their date of hire. Employees hired prior to December 15, 2001 have the first 6% of their contribution matched at 100% for the first two years of employment. After the first two years, the match decreases to 50% on the first 6% contributed. For employees hired on and after December 15, 2001, the Company matches 50% of the first 6% of the employee deferral. For December 31, 2004 and 2003, the cost of this plan was $944 and $763, respectively.

The Company also has a defined contribution pension plan covering all full-time employees. The Company contributes an amount equal to 6% of an employee's salary into the plan for the employee's retirement. For December 31, 2004 and 2003, the cost of this plan was $1,999 and $1,362, respectively.

Effective August 1, 1999, the Company adopted a Supplemental Executive Retirement Plan (SERP) for officers. In addition, on December 26, 2002, the Company also adopted a plan under Section 457(b) of the Internal Revenue Code ("457(b) plan"). Benefits payable under these plans are based upon the participant's salary and age. The investment balance at December 31, 2004 and 2003 is $761 and $565, respectively, and is recorded in cash and cash equivalents on the balance sheet. An offsetting liability for $761 is also recorded on the balance sheet in accrued liabilities. Expense relating to the SERP plan of $230 and $188 was recorded for the period ended December 31, 2004 and 2003, respectively. Expense relating to the 457(b) plan of $.1 was recorded for the period ended December 31, 2004 and $0 was recorded for 2003.

The Company has also adopted a Directors' Deferred Compensation Plan that permits non-employee directors to receive a portion of their fees and retainers as members of the Board of Directors and committees of the Board in a form other than as direct payments. For the period ended December 31, 2004 and 2003, $308 and $189 were recorded in accrued liabilities, respectively.

The Midwest ISO assumed a pension plan and a postretirement medical plan established for MAPPCOR, Inc. employees who became employees of the Midwest ISO under the terms and conditions of an asset purchase agreement completed in November 2001. The Plans are the Midwest ISO Floor Offset Plan and the Midwest ISO Voluntary Employee Benefits Association (VEBA), respectively. Assets totaling $168, the amount specified in the asset purchase agreement, were transferred to the VEBA upon direction of MAPPCOR, Inc. on January 29, 2003. Per the asset purchase agreement, no future contributions will be made to the VEBA. Future actuarial obligations to the Floor Offset Plan will be made as required, offset by the company's contributions to the Midwest ISO Retirement Savings Plan.

The following tables set forth plan information at December 31, 2004 and 2003. The December 31, 2004 and 2003 columns are based on an actuarial valuation of the Midwest ISO's Floor Offset Plan dated January 2005 and 2004, respectively:

**Actuarial present value of benefit obligations:**

| | 2004 | 2003 |
|---|---|---|
| Benefit Obligation | $3,400 | $2,868 |
| Fair Value of Plan Assets | 2,049 | 1,925 |
| Unfunded Status | $(1,351) | $(943) |
| Accrued Benefit Cost Recognized in the Balance Sheet | $(302) | $(149) |

**Weighted-average assumptions used to calculate the benefit obligation, as of December 31:**

| | 2004 | 2003 |
|---|---|---|
| Settlement (Discount) Rate | 5.60% | 6.00% |
| Expected Return on Plan Assets | 8.00% | 8.00% |
| Rate of Increase in Future Compensation Levels | 5.00% | 5.00% |
| Net Periodic Pension Cost / (Income) | $153 | $85 |
| Employer Contribution | - | - |
| Plan Participants' Contributions | - | - |
| Benefits Paid | - | - |

(Dollar amounts in thousands)

The Expected Return on Plan Assets is based on the market-related value of plan assets at the beginning of the plan year and the assumed long-term investment rate, adjusted for expected contributions and benefit payments during 2004. Receivable contributions not yet paid as of the plan year-end may not be considered as plan assets.

**Weighted-average assumptions used to calculate the net periodic pension cost, as of January 1:**

| | 2004 | 2003 |
|---|---|---|
| Settlement (Discount) Rate | 6.00% | 6.50% |
| Expected Return on Plan Assets | 8.00% | 8.00% |
| Rate of Increase in Future Compensation Levels | 5.00% | 5.00% |

**Plan Assets – Percentage of Fair Value by Category:**

| Asset Category | 2004 | 2003 |
|---|---|---|
| Equity Securities | 66% | 62% |
| Debt Securities | 33% | 34% |
| Real Estate | 0% | 0% |
| Cash and Cash Equivalents | 1% | 4% |
| Total | 100% | 100% |

The investment objective of the Midwest ISO Floor Offset Plan portfolio is to meet or exceed the actuarial assumptions pertaining to this floor offset plan. The following asset allocation guidelines have been established for this plan:

| | Minimum | Maximum | Target |
|---|---|---|---|
| Cash Equivalents | 0% | 5% | 0% |
| Fixed Income (Bonds) | 30% | 50% | 40% |
| Equity (Common Stocks) | 50% | 70% | 60% |

The above asset allocation guidelines are designed to achieve satisfactory investment returns while gaining the risk control of diversification. In addition, the guidelines have a minimum and maximum range to provide the trustee/investment manager the flexibility to respond to a change in market conditions.

**Expected Contributions During Fiscal 2005** $43

**Estimated Future Benefit Payments:**

| | |
|---|---|
| Fiscal 2005 | $18 |
| Fiscal 2006 | 27 |
| Fiscal 2007 | 44 |
| Fiscal 2008 | 57 |
| Fiscal 2009 | 114 |
| Fiscal 2010-2014 | 867 |

## 9. INCOME TAXES

The Company has received approval for not-for-profit status under Section 501(a) of the Internal Revenue Code, and is tax exempt. The Company also received not-for-profit status from the State of Indiana and the State of Minnesota. The Midwest ISO has incurred no unrelated business tax.

## 10. LEASES

### Capital Leases

The capitalized costs associated with lease obligations are included in fixed assets. Accumulated amortization on all leased assets is $9,697 and $5,900 at December 31, 2004 and 2003, respectively. The Company entered into a lease agreement on July 6, 2000 for construction of a new facility that was completed in April 2001. The capitalized costs associated with the new facility are $15,777 and are included in fixed assets. On July 26, 2002 the Company entered into a three-year lease agreement for an information back-up system. The capitalized cost associated with the information back-up system is $9,510, which is included in computer hardware. During 2004, the Company acquired additional hardware and software to support the Midwest Market Initiative under multiple capital lease arrangements. The three year lease agreements are capitalized on the balance sheet for $5,250.

Following is a schedule of minimum lease commitments for the year ending December 31, and annually thereafter:

| | |
|---|---|
| 2005 | $ 6,995 |
| 2006 | 4,119 |
| 2007 | 3,186 |
| 2008 | 1,677 |
| 2009 | 1,677 |
| Thereafter | 18,722 |
| Total minimum lease payments | 36,376 |
| Less-amount representing interest | (13,065) |
| Present value of net minimum capital lease payments | 23,311 |
| Less-current portion | (5,420) |
| Long-term portion | $17,891 |

(Dollar amounts in thousands)

### Operating Leases

The Company leases office space and equipment under noncancellable operating leases. Total expense incurred under all operating leases was $3,071 and $2,417 for the year ended December 31, 2004 and 2003, respectively. During 2003, the Midwest ISO executed three new operating leases for office expansion in Carmel, Indiana; one is for a conference center and two are for office space. During 2004, the Midwest ISO executed new operating leases for hardware to support the Midwest Market Initiative.

Future minimum lease payments under the noncancellable operating leases are as follows for the year ending December 31, and annually thereafter:

| | |
|---|---|
| 2005 | $ 4,248 |
| 2006 | 3,946 |
| 2007 | 3,174 |
| 2008 | 2,357 |
| 2009 | 1,436 |
| Thereafter | 7,183 |
| Total | $22,345 |

## 11. BANK LINE OF CREDIT

The Company has a line of credit expiring on October 22, 2007 with Bank One, N.A. The balance was $5,000 at December 31, 2003 and $0 at December 31, 2004. The interest rate at December 31, 2003 was 1.67%. The maximum amount available under the line was $105,000 at December 31, 2003 and $60,000 at December 31, 2004. Borrowings are payable on demand. Advances bear interest at either the floating rate or Eurodollar rate. The line of credit contains certain restrictive financial covenants and other covenants including limitations on indebtedness, participation in mergers, sale of assets, investments, acquisitions, liens, and prepayment of indebtedness.

## 12. LONG-TERM NOTES

### Long-term debt consisted of the following:

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| Notes payable, net of unamortized discount, bears interest semi-annually at 8.75%, maturing on June 1, 2012 | $ 99,706 | $ 99,667 |
| Notes payable, bears interest semi-annually at 4.62%, maturing on February 28, 2013 | 100,000 | 100,000 |
| Notes payable, bears interest semi-annually at 4.49%, maturing on January 16, 2014 | 125,000 | - |
| Notes payable, bears interest semi-annually at 3.61%, maturing on October 7, 2009 | 80,000 | - |
| Notes payable, principal due quarterly on the non-forgivable portion, plus interest of 3% per annum, maturing July 1, 2011 | - | 888 |
| Notes payable, principal due quarterly on the non-forgivable portion, plus interest of 3% per annum, maturing October 1, 2014 | 1,970 | - |
| | 406,676 | 200,555 |
| Less current portion | 99 | 124 |
| Total long-term debt | $ 406,577 | $ 200,431 |

Maturities of long-term debt are as follows:

| | |
|---|---|
| Year ending December 31, | |
| 2005 | $ 99 |
| 2006 | 20,135 |
| 2007 | 34,424 |
| 2008 | 52,286 |
| 2009 | 52,312 |
| Thereafter | 247,420 |
| | $ 406,676 |

On June 1, 2000 the Company issued notes with a face value of $100,000 to a group of institutional lenders. The notes were issued at a discount of $475; therefore, the net proceeds of the offering were $99,525. The notes are unsecured, senior obligations of the Company that mature on June 1, 2012, and bear interest at 8.75% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2000. The notes have no mandatory sinking fund requirement but are redeemable, in whole or in part, at the option of the Company. The notes contain certain restrictive covenants, including limitations on payments, liens, leases, distributions, purchases, and certain investments. The Company incurred note offering fees aggregating $675. Note offering fees are deferred and amortized as a component of interest expense over the term of the notes. The net proceeds were used to repay existing short-term indebtedness under the bank credit facility, capital expenditures associated with expansion in preparation for becoming fully operational, and operating expenditures.

On February 28, 2003 the Company issued notes with a face value of $100,000 to a group of institutional lenders. The notes are unsecured, senior obligations of the Company that mature on February 28, 2013 with mandatory principal prepayments of $14,286 payable beginning on February 28, 2007 and on each February 28 thereafter to and including February 28, 2012, and bear interest at 4.62% per annum, payable semi-annually on February 28 and August 28 of each year, commencing August 28, 2003. The notes have no mandatory sinking fund requirement but are redeemable, in whole or in part, at the option of the Company. The notes contain certain restrictive covenants, including limitations on payments, liens, leases, distributions, purchases, and certain investments. The Company incurred note offering fees aggregating $737. Note offering fees are deferred and amortized as a component of interest expense over the term of the notes. The net proceeds were used to fund the implementation of the market-based, congestion management system.

On January 16, 2004 the Midwest ISO issued notes with a face value of $125,000 to a group of institutional lenders. The notes are unsecured, senior obligations of the Company that mature on January 16, 2014 with mandatory principal prepayments of $17,857 payable beginning on January 16, 2008 and on each January 16 thereafter to and including January 16, 2013, and bear interest at 4.49% per annum, payable semi-annually on January 16 and July 16 of each year, commencing July 16, 2004. The notes have no mandatory sinking fund requirement but are redeemable, in whole or in part, at the option of the Company. The notes contain certain restrictive covenants, including limitations on payments, liens, leases, distributions, purchases, and certain investments. The Company incurred note offering fees aggregating $2,368. Note offering fees are deferred and amortized as a component of interest expense over the term of the notes. The net proceeds will be used to: (1) fund payments to third parties designated to receive them pursuant to the Participation Agreement among the Midwest ISO and Ameren, First Energy, NIPSCO, and National Grid USA; (2) to fund the deferral of costs otherwise recoverable pursuant to Schedule 10 of the Tariff in 2002 and 2003; (3) to fund the reimbursement of costs to those entities that qualify for reimbursement pursuant to the Midwest ISO Data Exchange Reimbursement Qualification Plan associated with the Midwest Market Initiative; and, (4) to complete other tasks associated with the normal business of the Midwest ISO in fulfillment of its obligation as an RTO.

On October 1, 2004 the Midwest ISO issued notes with a face value of $80,000 to a group of institutional lenders. The notes are unsecured, senior obligations of the Company that mature on October 7, 2009 with mandatory principal prepayments of $20,000 payable beginning on October 7, 2006 and on each October 7 thereafter to and including October 7, 2009, and bear interest at 3.61% per annum, payable semi-annually on April 7 and October 7 of each year, commencing April 7, 2005. The notes have no mandatory sinking fund requirement but are redeemable, in whole or in part, at the option of the Company. The notes contain certain restrictive covenants, including limitations on payments, liens, leases, distributions, purchases, and certain investments. The Company incurred note offering fees aggregating $446. Note offering fees are deferred and amortized as a component of interest expense over the term of the notes. The net proceeds are being used to: (1) fund payments to Illinois Power pursuant to the Participation Agreement between the Midwest ISO and Illinois Power; (2) to fund the deferral of development and start-up costs associated with the Midwest Market Initiative; and, (3) to complete other tasks associated with the normal business of the Midwest ISO in fulfillment of its obligation as an RTO.

During August 2001, the Midwest ISO received proceeds of $1 million from a loan with the Indiana Development Finance Authority (IDFA). The obligation is divided into a $500 non-forgivable and a $500 forgivable piece. The non-forgivable piece matures on July 1, 2011 and bears interest at 3% per annum with principal and interest payable quarterly beginning October 1, 2001. The forgivable piece matures on July 1, 2011 and bears interest at 3% per annum with principal and interest payable quarterly beginning January 1, 2003. As part of the October 1, 2004 loan agreement discussed below, the original note of $1 million was forgiven. The balance outstanding was $878 at the time of forgiveness.

On October 1, 2004, the Midwest ISO received proceeds of a $2 million loan from the Indiana Development Finance Authority (IDFA). The obligation is divided into a $1,500 non-forgivable and a $500 forgivable piece. The non-forgivable piece matures on October 1, 2014 and bears interest at 3% per annum with principal and interest payable quarterly beginning January 1, 2005. The forgivable piece matures on October 1, 2014 and bears interest at 3% per annum with principal and interest payable quarterly beginning October 1, 2009. Payment on the forgivable piece will be deferred until maturity and then deemed paid as long as the Midwest ISO continues to meet the community investment goals identified in the agreement. The loan is collateralized by $2.1 million in video and console equipment.

## 13. GRANTS

Effective May 31, 2001, the State of Indiana, acting by and through the Economic Development for a Growing Economy (EDGE) Board, agreed to provide the Midwest ISO a payroll tax credit worth $3.1 million over 10 years. The credit is part of an economic development incentive package that the State of Indiana offered the Company to locate in central Indiana. This grant program is designed to help current and new employers with location and development costs, with the goal of fostering job creation in Indiana. The Midwest ISO must continue to fulfill its responsibilities to the community as stated in the agreement in order to file for annual payroll tax credits over a 10-year period. During 2003, the Midwest ISO filed with the state to receive $300 in credits for 2002. In 2004, the Midwest ISO filed with the state to receive $493 in credits for 2003. During 2004, the Midwest ISO filed with the state to obtain additional EDGE credits based on the jobs created for the Midwest Market. The state granted $6 million over 10 years in addition to the $3.1 previously granted.

Effective August 28, 2001, the State of Indiana, acting by and through the Indiana Department of Commerce, agreed to provide the Midwest ISO an Economic Development Grant worth $500 to the Midwest ISO. This Grant program is designed to encourage new businesses to invest in Capital in the State of Indiana. The Midwest ISO was required to spend $1,086 in new Capital and the State of Indiana would reimburse $500. During 2003, the Midwest ISO filed with the state to receive $500 in Capital reimbursements for the period May 2001 to March 31, 2003. On January 23, 2004, the Midwest ISO received payment from the State of Indiana for $500.

Effective October 9, 2001, the State of Indiana, acting by and through the Indiana Department of Commerce, agreed to provide the Midwest ISO a Skills Enhancement Contract worth $200 to the Midwest ISO. This Grant program is designed to encourage employers to give their employees the skills they need to function in positions properly. The Midwest ISO was required to spend $350 on training for employees and the State of Indiana would reimburse $200. During 2003, the Midwest ISO filed with the state to receive $200 in Grant reimbursements for the period October 9, 2001 to December 31, 2003. On January 23, 2004, the Midwest ISO received payment from the State of Indiana for $200.

## 14. RELATED PARTY

On December 31, 2004 and 2003, the Company held accounts receivable of $27 and $26 from employees, respectively.

## 15. COMMITMENTS AND CONTINGENCIES

There are various claims against the Company incident to its operations. It is the opinion of management that the ultimate resolution of these matters will not have a material adverse effect on the Company's financial position or results of operations.

On August 14, 2003, portions of the northeastern U.S. and southern Canada suffered a major power outage (the "August 14th Outage"). Midwest ISO officials participated in root cause analysis with the Department of Energy (DOE) and NERC to determine the cause of the outage. To date the DOE has issued three reports on the August 14th Outage, a report on the sequence of events leading up to the August 14th Outage, an interim report on the causes of the August 14th Outage, and a final report with recommendations to prevent such events in the future.

The Midwest ISO has received various inquiries from an insurance company as a result of the August 14th Outage. No person has asserted a claim against the Midwest ISO arising out of the August 14th Outage; however, there can be no assurance that a claim will not be asserted and, if a claim is asserted, there can be no assurance as to the outcome of such a claim. Management does not believe that a basis for imposing liability on the Midwest ISO has been shown.

The Company enters into a variety of contracts with third parties. Management has evaluated these contracts and determined that these contracts are not required to be recorded or disclosed in the financial statements as obligations of the Company.

# MANAGEMENT CERTIFICATION

## I CERTIFY THAT:

1. I have reviewed this report of the Midwest ISO for the year ended December 31, 2004;
2. Based on my knowledge, this report does not contain any untrue statements of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Midwest ISO as of, and for, the periods presented in this report;
4. The Midwest ISO's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures for the Midwest ISO and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Midwest ISO is made known to us by others within the Midwest ISO, particularly during the period in which this report is being prepared;
   b. Evaluated the effectiveness of the Midwest ISO's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c. Disclosed in this report any change in the Midwest ISO's internal control over financial reporting that occurred during the Midwest ISO's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Midwest ISO's internal control over financial reporting; and
5. The Midwest ISO's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Midwest ISO's auditors and the audit committee of Midwest ISO's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Midwest ISO's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the Midwest ISO's internal control over financial reporting.

Date: February 11, 2005

J. P. Torgerson

James P. Torgerson
PRESIDENT AND CHIEF EXECUTIVE OFFICER

Michael P. Holstein

**Michael P. Holstein**
VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

## DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report.

Based on that evaluation, we have concluded that the Midwest ISO's disclosure controls and procedures are functioning effectively to provide reasonable assurance that the Midwest ISO can meet its disclosure obligations. The reporting process is designed to ensure that information required to be disclosed by the Midwest ISO is recorded, processed, summarized and reported within the appropriate time periods. To facilitate this process the Midwest ISO has formed a Disclosure Committee consisting of key company personnel designed to review the accuracy and completeness of all disclosures made by the Midwest ISO.

In connection with the evaluation described above, there were no changes in our internal control over financial reporting during the quarter ended December 31, 2004 that have materially affected, or were reasonably likely to materially affect, our internal controls over financial reporting.

Date: February 11, 2005

J. P. Torgerson

James P. Torgerson
PRESIDENT AND CHIEF EXECUTIVE OFFICER

Michael P. Holstein

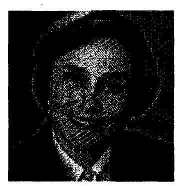
Michael P. Holstein
VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

# INDEPENDENT, NEUTRAL, INVOLVED

The Midwest ISO Board of Directors is comprised of seven individuals plus the President of the Midwest ISO. To qualify as a director, an individual cannot have been at any time within two years prior to their election, a director, officer or employee of a Midwest ISO member, user or an affiliate of a member or user. While serving on the Board of Directors, and for two years thereafter, a director cannot have a material business relationship or other affiliation with any member, user or affiliate thereof. Four of the seven elected directors are required to have expertise and experience in corporate leadership at the senior management or board of director level, or in the professional disciplines of finance, accounting, engineering, or utility laws and regulation. Of the remaining three directors, one must have expertise and experience in the operation of electric transmission systems, one must have expertise and experience in the planning of electric transmission systems, and one must have expertise and experience in commercial markets and trading and associated risk management. Each successor director serves a three-year term.

**James H. Young, Jr.**
Chairman of the Board
Original Board Member
Former Senior Vice President, Business Development — South Carolina Electric & Gas Company
Columbia, SC

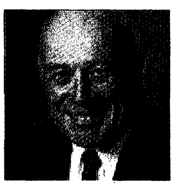
Committees: Audit & Finance



**Judy Walsh**
Joined Board: January 2005
Former Senior Vice President of Government Affairs and Senior Vice President of Regulatory Policy — SBC Communications

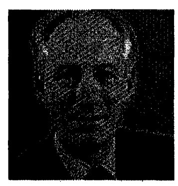
Former Commissioner — Public Utility Commission of Texas
San Antonio, TX

Committees: Audit & Finance, Markets



**Paul E. Hanaway**
Vice Chairman of the Board
Original Board Member
Former Commissioner — Rhode Island Public Utilities Commission
Glen, NH

Committees: Human Resources, Markets, Nominating

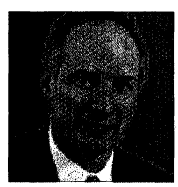


**J. Michael Evans**
Joined Board: March 2005
Former President and Chief Operating Officer — Consolidated Edison Company of NY, Inc.
Stuart, FL

Committees: Human Resources

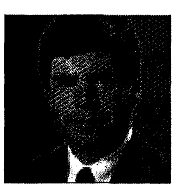
**William P. Vititoe**
Original Board Member
Former Chairman, Chief Executive Officer and President — Washington Energy
Grosse Pointe, MI

Committees: Human Resources (Chair), Nominating (Chair)



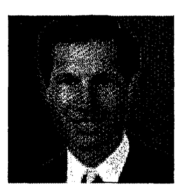
**Paul J. Feldman**
Joined Board: March 2005
Former President and Chief Executive Officer — Columbia Energy Services
Great Falls, VA

Committees: Markets (Chair)



**T. Graham Edwards**
Joined Board: January 2001
Former President and Chief Executive Officer — Santee Cooper
Moncks Corner, SC

Committees: Audit & Finance (Chair), Human Resources, Nominating



**James P. Torgerson**
Joined Board: December 2000
President and Chief Executive Officer — Midwest ISO
Fishers, IN

# MIDWEST ISO OFFICERS

**James P. Torgerson**
President and Chief Executive Officer

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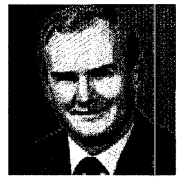

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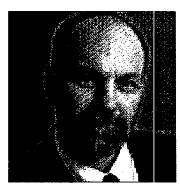

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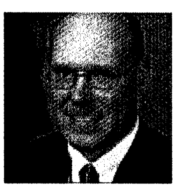

**Mark J. Griffin**
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**William C. Phillips**
Vice President of Interregional Coordination and Policy

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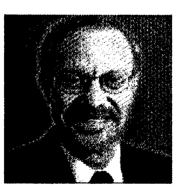

**Roger C. Harszy**
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**Jim Schinski**
Vice President and Chief Information Officer

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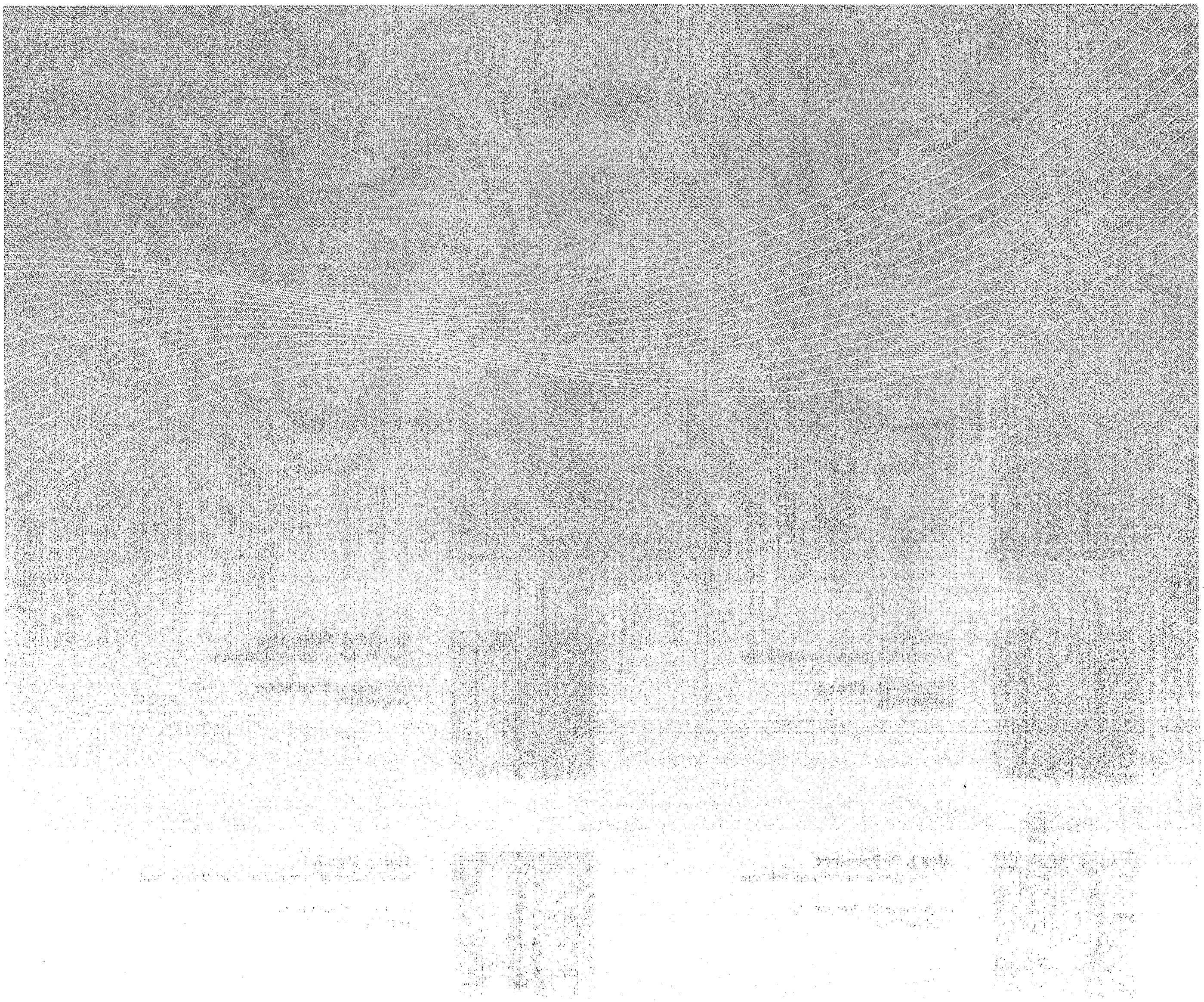

Midwest ISO
We manage power.

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