Organization of MISO States

ORGANIZATION OF MISO STATES, INC.
Board of Directors Meeting
Conference Call Minutes
November 12, 2009

Approved January 21, 2010

Valerie Lemmie, Vice-President of the Organization of MISO States, Inc. (OMS), called the November 12, 2009 meeting of the OMS Board of Directors to order via conference call at approximately 1:00 p.m. (CST). The following board members or their proxies participated in the meeting:

Bill VanderLaan, proxy for Sherman Elliott, Illinois
Dave Johnston, proxy for Jim Atterholt, Indiana
Jeff Kaman, proxy for Rob Berntsen, Iowa
Bill Bowker, proxy for David Armstrong, Kentucky
Angie Butcher, proxy for Monica Martinez, Michigan
Burl Haar, proxy for Tom Pugh, Minnesota
Robert Kenney, Missouri
Brian Dekiep, proxy for Greg Jergeson, Montana
Jerry Lein, proxy for Tony Clark, North Dakota
Valerie Lemmie, Ohio
Tyrone Christy, Pennsylvania
Greg Rislov, proxy for Gary Hanson, South Dakota
Randel Pilo, proxy for Lauren Azar, Wisconsin

<u>Absent</u>
Manitoba

<u>Agency members participating</u>
Frank Bodine – Iowa
Bill Bokram, Wanda Jones – Michigan
Marya White – Minnesota
Quanetta Batts, Hisham Choueiki – Ohio
Jerry Lein – North Dakota
John Feit, Gail Maly, Don Neumeyer – Wisconsin

<u>Others on the call</u>
Bill Smith, Julie Mitchell – OMS Staff

The directors and proxies listed above established the necessary quorum for the meeting of at least eight directors being present.

Approval of Minutes from October 8th and October 30th, 2009 Board of Directors meetings

Brian Dekiep moved for approval of the minutes of the October 8 and October 30 board meetings. Randel Pilo seconded. The motion was approved by unanimous voice vote.

Treasurer's Report – Burl Haar

The beginning balance as of October 1 for the Wells Fargo Business Performance Savings Account was $59,656.30. Interest earned for this month was $10.14. The October 31, 2009 balance was $59,666.44.

The beginning balance as of October 1 for the Chase Bank One Checking account was $74,929.04. The total disbursements from the checking account for October 2009 were $34,820.43. Deposits, interest and adjustments were $40,000.75. As of October 31, 2009, the checking account bank balance was $83,534.14 and the book balance was $80,109.36 (with 8 checks outstanding).

The total savings and checking account balances as of October 31, 2009 is **$139,775.80.**

Burl Haar moved for acceptance of the treasurer's report. Brian Dekiep seconded. The motion was approved by unanimous voice vote.

Review of the Executive Committee Meeting – Bill Smith

The Executive Committee Meeting for October was cancelled.

Administrative Report from Executive Director – Bill Smith

A written report was submitted prior to the meeting. Randel Pilo requested that Bill Smith report on the MISO-PJM settlement at the next meeting where there are fewer proxies and more commissioners.

Work Group Status Reports

<u>Demand Response WG</u> – John Feit

- A written report follows the minutes;

<u>Transmission Cost Allocation WG</u> – Bill VanderLaan

- Bill VanderLaan gave a verbal report. There has been a request for comment from FERC on transmission cost allocation and planning. FERC issued an order on cross border facilities cost allocation and that will be getting attention in the near future;

<u>Markets and Tariffs WG</u> – Bill Bokram

- Written report follows minutes;
- Randel Pilo moved for the Markets and Tariffs Work Group to continue to monitor the LTTR issue. Angie Butcher seconded. The motion passed by unanimous voice vote;

<u>Resources WG</u> – Don Neumeyer

- Written report follows minutes;
- Don Neumeyer also discussed moving the price responsive demand issue from the Resources WG to the Demand Response WG;

<u>Regional Planning WG</u> – Jerry Lein

- Written report follows minutes;

<u>Governance and Budget WG</u> – Burl Haar

- Written report follows minutes;

Modeling WG – Hisham Choueiki

- Written report follows minutes.

BUSINESS

1. Presentation: Transmission Development Challenges – an independent developer & TDU perspective – Brian Rushing, LS Power

- Brian Rushing discussed this presentation with the Board and staff and took questions.

2. Presentation: "Maximizing TO revenues" – JoAnn Thompson, Otter Tail Power

- JoAnn Thompson gave a short presentation on transmission service revenues, including the history of the agreement currently in place between the TOs and MISO. She and Paul Duke then took questions from the Board and staff. Written follow ups will be provided to Bill Smith who will distribute them to the Board and staff.

3/4. MISO Advisory Committee & Planning Advisory Committee Reports – Valerie Lemmie

- The minutes of the last meetings have been provided along with the upcoming agenda for the November A/C meeting.
- Commissioner Lemmie pointed out that the Chair and Vice-Chair of the A/C committee is up for nomination. If there is any interest on the OMS side for those positions, immediately let Bill Smith know.

5. Update on Price Responsive Demand – moving from the Resources WG to the Demand Response WG

- Don Neumeyer covered this in his work group update.

6. Action Item: Proposed Changes to the Document entitled "OMS Process for Approving Position Statements for FERC and MISO"– G&B WG

- As this is a by-law change, due the number of proxies on the call, it was decided to table the document until the next board meeting.

7. Action Item: Reponses to FERC Questions in Docket AD09-08 – TCA & RP WG's

- The group discussed some minor edits requested by Kentucky.
- Minnesota requested a change in regards to the right of first refusal language.
- It was decided to vote on the document as the Board has it now. If any changes are made that are substantive, the document will be brought back to the board and re-voted on.

Randel Pilo moved to vote on the document. David Johnston seconded. The motion passed by unanimous voice vote.

A roll call vote was taken:

Illinois – Abstain
Indiana – Yes
Iowa – Yes
Kentucky – Abstain
Manitoba – Absent
Michigan – Yes
Minnesota - Yes
Missouri – Abstain
Montana – Abstain
North Dakota – Yes

Ohio – Yes
Pennsylvania – Yes
South Dakota – Yes
Wisconsin – Yes

The motion passed with 9 states voting yes, 4 state abstaining and one state absent.

8. Report: Eastern Interconnection Planning Process Update – Lauren Azar

- Commissioner Azar was not on the call, so no report was given.

9. Update on the RECBTF – Lauren Azar

- Commissioner Azar was not on the call, so no report was given.

ADJOURNMENT

The OMS Board of Directors meeting adjourned at 2:50 pm CST.

OMS Demand Response and Technology Working Group

1. Comments on Midwest ISO ARC Filing, Docket ER09-1049-002

On October 2, 2009, the Midwest ISO filed proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff to accommodate the participation of ARCs in the Midwest ISO in accordance with Orders 719 and 719-A. The OMS Demand Response and Technology Work Group held a conference call on October 27 to discuss draft comments. The OMS approved the proposed comments on October 30. The comments were filed with the FERC on November 5.

2. Measurement and Verification of ARC Load Reduction.

The Midwest ISO Demand Response Working Group will be developing and reviewing the measurement and verification protocols for load reductions. The M&V protocols will be incorporated into the Business Practices manuals. The M&V protocols are an essential element for proper compensation for load reductions and capacity certification and for the prevention of gaming, which has been an issue in other ISOs.

3. Inter-Regional Trading of Renewable Energy Credits.

The Demand Response and Technology Working Group will be scheduling a conference call within the next several weeks to discuss this issue.

4. Price Responsive Demand.

The Demand Response and Technology Working Group has been assigned to work on this issue. A specific work plan will be developed following the conference call with Potomac Economics which is scheduled for November 12.

OMS Resources Work Group
Status Report to OMS Board of Directors – November 12, 2009

1. **LOLE 2010 Study Report**

The 2010/11 planning year findings were released at the end of October.

- The Planning Reserve Margin (PRMsysingen) installed MISO generation stayed at 15.4% due equal off-setting effects. The EFORd's went up, but there less congestion and there was more utilization of external ties.
- The PRMlseigen for LSEs dropped from 12.69% to 11.94%. Besides the above effects, the load diversity factor changed from 2.35% to 3.00%. This is due to another year of data and shifting to a CP node basis.
- The PRMucap will drop from 5.35% to 4.50% for compliance. This is due to all the off-setting effects noted above.

2. **Resource Compliance Template**

Don Neumeyer sent out a survey to the States on the monthly compliance template reports, including the confidential state report on its content. He will follow up with individual calls.

3. **Resource Adequacy Hot Topic**

Resource Adequacy is the Hot Topic for December. The WG has responded and the responses are being compiled Nov 9th. They will be sent out immediately.

4. **SAWG**

Some of the other issues that are active include:

- LMR Deliverability – MISO has shown that some behind the meter generation and DR programs may not be deliverable to the MISO footprint due to local/sub-regional transmission constraints. They will study the system annually for an assessment
- Wind capacity credit for 2010/2011 – The LOLE WG is collecting comments about the probability distribution of wind during peak periods to determine. This will be reported to SAWG. That will report will be shared with stakeholders. That report will in turn will be shared with the Resources WG for comments.

5. **LSE Under-Forecast Assessment**

Below is a portion of the November report to SAWG:

S55 Data	June	July	August	June	July	August
	All	All	All	No RCS	No RCS	No RCS
Total Demand Forecasted (in MW)	91,682	108,086	106,355	N/A	N/A	N/A
Total Actual Demand (in MW)	95,186	84,421	93,865	N/A	N/A	N/A
# of CP nodes underforecasted (StDev and Losses included)	83	34	45	30	7	11
# of Market Participants that Underforecasted	45	29	32	15	5	10
# of CP nodes that reported StDev	127	159	159	N/A	N/A	N/A
# of CP nodes that reported Weather Normalization	4	N/A	N/A	N/A	N/A	N/A
Total CP nodes	264	264	264	134	134	134

Load nodes underforecasted in June, July, **and** August = 12
Load nodes underforecasted in two of the three months = 30

No RCS= does not include Retail Choice States IL, OH, MI
Weather normalized actual demand will be provided as soon as it becomes available

There was discussion about having some additional information on the distribution of the MW distribution in relationship to the # of CP nodes. Some small nodes could have under forecasting, but only a few MWs. So the cumulative risk is hard to assess. The issue of weather normalization for the whole LSE versus individual CP node was discussed. Then there was general mention of the recession continuing to impact sales. Another issue is how or not report non-jurisdictional LSEs to some states, yet they are in the planning pool which has potential impacts to the regulated LSE shedding non-firm and possibly firm load during Emergency Operating Procedures.

The SAWG would like some detailed feedback on the report from OMS:

- Granularity of reporting (LSE vs. Commercial Pricing Node)
- Reasonability band that could be applied to minimize reporting of under forecasts below a certain magnitude (identify gaming or situations that potentially harm reliability only)
- Feedback on Draft LSE Under Forecast Reporting template (attached)
- Should PRC designations be considered or should the two processes remain separate? (LSE over designates PRC to "hedge" under forecast)
- Under Forecast reporting of non-jurisdictional entities

6. Price Response Demand

At the October OMS Board meeting is was decided to leave the door open to further discussions on the use of PRD. The work effort will continue with the new OMS Demand Response WG. A contact is schedule with Dr. Patton to gain additional insight on his previous written comments on not sharing planning resources during emergency procedures. Also since the last discussion the final report a Demand Response Availability Data System was issued in September. That 67 page report does recognize PRD as real time pricing method in the non-dispatchable, time sensitive category just as Critical Peak Pricing, TOU, etc.

7. Volunteer Capacity Auction

Depending on one's view the activity is volatile or indicates that off-season months have much less value during a recession.

APRCs	Dec–09	Nov-09	Oct-09	Sep-09	Aug-09	Jul-09
Offers submitted	19,688.3	22,424.9	22,312.5	13,729.5	3,588	363.8
Bids submitted	1,226.0	1,038.6	614.9	300	110	1,216.6
Cleared Amount	1,226.0	1,038.6	614.9	300	110	363.8
Clearing Price	$0.75	$0.50	$0.05	$0.01	$1	$10,015

FERC Request For Comments

The Regional Planning Workgroup and the Cost Allocation Workgroup worked together to draft a response to the FERC Request for Comments regarding transmission planning processes and cost allocation. The draft is currently before the OMS Board on today's meeting agenda.

New PAC Chair

Bob McKee took over as chair of the PAC starting in November 2009.

MTEP- 09

A PAC meeting was held in early October to finalize review and prepare comments on MTEP09. The PAC approved a motion to forward the MTEP09 report to the Advisory Committee and Board of Directors for approval. The Advisory Committee opted at its October meeting not to take a vote on MTEP09 and relied on the expertise of the PAC. The Midwest ISO Board is expected to vote whether to approve MTEP09 during its December meeting.

MTEP 09 contains 21 projects totaling $292 million that are eligible for cost sharing. Projects to be eligible for RECB base line reliability/GIP cost sharing include 3 projects in the east totaling approximately 88 million, four projects in the Central region totaling approximately $99 million and 13 projects in the west totaling approximately $108 million. Additionally, MTEP-09 includes the first regionally beneficial project with RECB II cost sharing. That project is P2794, a 345 kV tie line between the Coffeen and Coffeen North substations in south central Illinois.

MTEP-10

<u>Proposed Scope of Work in 2010</u>

Transmission solutions to address constraints not otherwise currently classified either as reliability or economic projects. Determine if the proposed solutions may have other reliability or economic benefits.

Potential new targeted studies include (1) planning for constraints resulting in LTTR infeasibility; (2) planning for constraints resulting in reduced deliverability of network resources; and (3) Southeast Wisconsin Issues Study.

Interconnection Process Task Force

The Midwest ISO Interconnection Process Task Force met August 27th in Carmel. The agenda included presentations on Injection/Withdrawal transmission rate design, temporaryGenerator Interconnection Agreement Limits and results of a survey seeking feedback on queue reform effectiveness.

Midwest ISO Studies are ongoing/done for ~37,500 MW of wind generation. Total RPS Mandates for Midwest ISO regions are ~ 23000 MW

The Midwest ISO plans to go forward with FLIP proposal starting with identification and subscription and continuing with proposal development beginning in October.

A workshop on the queue process was held on September 24 in Wisconsin. Next workshop is scheduled for November 12 in Saint Paul, Minn.

RGOS I

Purpose – To provide indicative transmission and generation to the regulatory community for input concerning the renewable zone strategy.

Status – Indicative costs ranging approximately $150 - $170 per MWh over the 15/25 GW and 345/765 kV scenarios have been released. Further studies including dynamic stability analysis and development of more accurate cost estimates for transformers/substations are underway.

RGOS II

RGOS II is designed to develop transmission alternatives needed to implement Renewable Portfolio Standards or goals at the least cost for consumers while continuing to reliably serve load.

In addition to the five RGOS I states, RGOS II covers Missouri, Illinois, Indiana, Michigan, Ohio and Pennsylvania. Any increases for RGOS I states will also be included.

Analysis will be performed in an open and transparent fashion involving stakeholders throughout, coordinate with neighboring systems.

The study is a Mid-term (5-15yr) bridge between the Generator Interconnection queue and longer term planning efforts.

RGOS II is a targeted study that is a coordinated effort within the Midwest ISO Transmission Expansion Plan (MTEP) “umbrella” that is intended to develop real projects.

Status: Indicative costs ranging from $80 Billion to $118 Billion over Local, Regional, RegionalOptimized, Combination and Combination 75/25 scenarios have been preliminarily identified.

EWITS Study Status & Schedule

Progress has been made in recent weeks towards successful completion of the Eastern Wind Integration and Transmission Study (EWITS, Phase I). The study team has been working hard to incorporate into the report the many excellent comments and recommendations from Technical Review Committee members in October. The final report will include updated scenarios of the future and Atlantic off-shore wind. The schedule has been adjusted to accommodate the suggestions for improvements.

In order to ensure a high quality final report, the public release of the EWITS report has been pushed back to mid-January (January 20th).

CARP - Injection/Withdrawal Methodology

The Midwest ISO recently had walk-through of a large spreadsheet prepared by Brattle Group that simulates the different possibilities for the injection/withdrawal methodology. The metrics include such items as: usage and access; local, sub-regional, and regional; generator and load, pricing zones, state footprints, etc. The OMS staff has just received a copy. The other Midwest ISO RECB stakeholders had their review November 9th.

The **OMS Governance and Budget Work Group** (G/B WG) is responsible for assessing the reasonableness of the Midwest ISO's new products and services, strategic plan, short-term and long-term incentive plans, and budgets.
http://www.misostates.org/WG9LongTermDevelopmentWIP.htm.

Work Group Update:

1. **Protocol for determining OMS voting on Advisory Committee action items.**
The Work Group chairs and some members of the Work Group have preliminary discussions on the protocol for determining OMS voting distributions on Advisory Committee action items. A memo reflecting those discussions is being prepared and will be presented to the Work Group in time to develop a Group recommendation for presentation at the December Board meeting.
2. **Midwest ISO Proposed 2010 Incentive Metrics**
The G& B WG is preparing staff comments for submission to the Midwest ISO. The notice soliciting stakeholder comments from the Midwest ISO was received on Nov. 10 and is due on the 20th. Assuming OMS wants to make some sort of comment on this proposal, MISO's extremely short turn around will necessitate the filing of only Staff comments.
3. **Bylaw changes**
The Work Group has developed proposed bylaw amendments for consideration by the Board at the 2009 Annual Meeting. The Board amended the bylaws at that meeting.
4. **Midwest ISO 2010 Capital Budget**
The Work Group reviewed the proposed 2010 Midwest ISO capital budget and developed recommendations for OMS Board consideration at its October Board meeting.
5. **Transmission Owners Agreement – language regarding maximization of revenues**
The Work Group arranged for a briefing from members of the Transmission Owners sector to discuss the language in Article II, Section II, D of the TO Agreement that creates a fiduciary obligation for the Midwest ISO to "maximize transmission service revenues associated with 'Transmission Services,' as defined in the Transmission Tariff . . ." The suggestion was made to the TO representatives to drop that phrase from the Section. The Work Group is waiting to learn what action, if any, was taken by the TOs on this recommendation.
6. **Value Proposition**
Working with the Modeling Work Group to develop comments.
7. **Midwest ISO budget development**
No change from last report

Modeling Workgroup mini-Report

(a) Value Proposition: The modeling workgroup had a conference call with MISO on November 4th to discuss the concerns and questions that were sent to MISO staff after the conclusion of the value proposition workshops in September and October. The discussion was quite informative, and MISO did a good job addressing our concerns and answering our detailed list of questions.

The major discussion points were

1) the newly introduced methodology for measuring reliability improvements,
2) the methodology for measuring improvements in dispatching efficiency, and
3) the methodology for estimating net savings due to capacity construction deferrals.

(b) Transmission Planner Position: A task force is currently compiling position descriptions for a Transmission Planner position to be hired by the OMS. We have received PD information from Transmission Owners, ISO's, and State Regulatory Agencies. Once we have a draft PD, we will circulate among the members of the task force. If OMS staffers are interested in being on this task force, please notify Bill and Hisham of your interest.

OMS

Organization of MISO States
Report of the Treasurer
Tom Pugh, Minnesota Public Utilities Commission
to the
Board of Directors
November 12 2009
Report for October 2009

CASH ON HAND

The beginning balance as of October 1 for the Wells Fargo Business Performance Savings Account was $59,656.30. Interest earned for this month was $10.14. The October 31, 2009 balance was $59,666.44.

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The total savings and checking account balances as of October 31, 2009 is $139,775.80.

OMS Treasurer Report for Month of October 2009

Wells Fargo Business Performance Savings Account

Beginning Balance	59,656.30	
Interest Earned this Month	10.14	
Ending Balance		59,666.44

Chase Bank One Checking Account

Beginning Balance	74,929.04	
Total Disbursements	(34,820.43)	
Deposits/Interest/Adjustments	40,000.75	
Ending Balance		80,109.36
Total Savings & Checking Balances as of October 31, 2009		**139,775.80**

8 checks outstanding at 10/31/09

OMS
Organization of MISO States

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OMS Executive Director Report
November 7, 2009

FERC and DOE Activity

1. Settlement discussions relating to formula rate issues are nearing completion in the Green Power Express docket, ER09-681. An offer of settlement should be filed with the Commission this month.
2. An initial settlement conference was held on October 19-20 in an undocketed matter involving market settlement errors between PJM and the Midwest ISO. After information exchanges between the RTOs, another conference is scheduled December 10-11 at the FERC offices. Docket No. ND10-1.
3. On October 23, the FERC conditionally accepted the Midwest ISO filing on RECB phase 1, addressing the "Otter Tail" problem of transmission facilities primarily added to serve export needs. The Commission required further filings on cost allocation by July 15, 2010. 129 FERC ¶ 61,060.
4. The FERC extended the filing date for response to questions on Order 890 planning issues from November 9 to November 23. Docket No AD09-8.
5. On November 5, the OMS filed comments on the Midwest ISO's filing on Aggregation of Retail Customers in compliance with Order 719 and 719-A. FERC Docket 09-1049.
6. FERC staff has scheduled a technical conference November 19-20 to discuss possible elements of a National Action Plan on Demand Response. Docket No. AD09-10. FERC extended a particular invitation to State Staff to participate in the conference. Details are in a November 6 e-mail from Julie Mitchell.
7. On November 3, the FERC issued an order on cross-border cost allocation between PJM and the Midwest ISO. 129 FERC ¶ 61,102. The order accepts proposed revisions to the Joint Operating Agreement to allocate costs of projects built in one RTO for economic benefits to the other.

OMS-MISO Activity:

1. The OMS held a cost allocation / regional planning (CARP) workshop October 29-30. Future meetings are scheduled November 18-19 (Chicago) and December 14-15 (Carmel).
2. On November 4, Midwest ISO staff briefed OMS on state reporting of Module E capacity data to state commissions.
3. Also on November 4, Midwest ISO staff briefed the OMS on refinements of the Value Proposition.
4. OMS representatives met on November 4 with Brattle Group analysts for a technical walk-through of the Injection-Withdrawal concept for transmission cost allocation.
5. On October 20, the Midwest ISO filed improvements and clarifications to the Resource Adequacy Requirements (RAR) portion of its Tariff (Module E). FERC Docket No. ER10-86.

Public Relations

1. Presentations:
   - None.

2. Pending speaking/meeting invitations:
   - None.

Upcoming MISO Filings of Regional Interest

Filing Date	Docket No.	Description	Pursuant to Commission Order	Working Group/ Committee where issue/change will be reviewed
November 2009	ER10-___-000	The Midwest ISO to submit proposed revisions to the Tariff to replace counterflows for restoring Long-term Transmission Rights (“LTTRs”) with an annual process permitting Market Participants to terminate their LTTRs.	N/A	N/A
12/01/2009	ER08-394-004 ER08-394-	The Midwest ISO to submit a report detailing how the overall generation mix affects the planning reserve margin	126 FERC ¶ 61,143	N/A

	005	calculated for planning zones.		
01/22/2010	ER07-235-000	The Independent Market Monitor ("IMM") to submit an annual Informational Report regarding the Establishment of New Narrowly Constrained Areas ("NCAs").	118 FERC ¶ 61,020	(2007)

Other upcoming dates:

- Next OMS Executive Committee meeting: **November 23** at 1:00 pm CDT
- OMS regular Board of Directors meetings: **November 12 and November 30 (Monday).**
- OMS Cost Allocation and Regional Planning Meetings, **November 18-19 (Chicago), and December 14-15 (Carmel).**

Report to OMS Board of Directors

November 12, 2009

OMS Demand Response and Technology Working Group

1. Comments on Midwest ISO ARC Filing, Docket ER09-1049-002

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Work Group Update:

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2. Midwest ISO Proposed 2010 Incentive Metrics

The G& B WG is preparing staff comments for submission to the Midwest ISO. The notice soliciting stakeholder comments from the Midwest ISO was received on Nov. 10 and is due on the 20^{th}. Assuming OMS wants to make some sort of comment on this proposal, MISO's extremely short turn around will necessitate the filing of only Staff comments.

3. Bylaw changes

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4. Midwest ISO 2010 Capital Budget

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5. Transmission Owners Agreement – language regarding maximization of revenues

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6. Value Proposition

Working with the Modeling Work Group to develop comments.

7. Midwest ISO budget development

No change from last report

1. Financial Transmission Rights (FTRs)

The MISO FTR Working Group meets each month (12/8 next mtg) with the objective of finding ways to improve funding available to pay FTR revenues. It reports to the MSC.

The M&TWG addressed a concern regarding Long Term Transmission Rights via a conference call held on 10/21 with Mike Stuart of WPPI Energy. In our 10/28 report to the Board, we summarized WPPI *et al* concerns regarding difficulties obtaining long term congestion protection for new baseload resources during the Stage 1A process of LTTR allocation, and **the M&TWG recommended that the OMS Board find this issue merits attention and direct the M&TWG to monitor the issue through the appropriate MISO stakeholder groups and to ask MISO to provide any further information regarding the concerns raised and expected priority so that we can better assess and monitor the problem and report further findings to the Board.** The October 28th LTTR Report summarizing the concerns raised, along with the WPPI memo and presentation, is attached hereto.

Regarding MISO-PJM market-to-market coordination and correction and resettlement of market flow errors discovered earlier this year, settlement discussions began at FERC on 10/14 to determine refunds (FERC docket ND10-1-000). MISO provided an update at the 11/3 MSC meeting. Data requests are due 10/23, responses due 10/30. MISO is to offer a proposal by 11/13. The next settlement conference will be on 12/10-11/09. OMS plans to attend.

Jim Wottreng tracks issues here for our group.

Status: Continuing monitoring.

2. Revenue Sufficiency Guarantee (RSG)

The MISO RSG WG meets each month (12/4 next mtg) and reports to the MSC. Issues are on two fronts: The RSG design going forward, and RSG resettlement.

Attached is a more detailed summary and status by Jim Wottreng. Highlights include:

RSG Resettlement: In the June 12, 2009 Order, FERC used its discretion to waive refunds prior to November 5, 2007. As a result, RSG resettlement was required to fix the Rate Mismatch from November 5, 2007 through November 9, 2008 and the RSG Interim Rate method (removal of the RSG exemption if do not Actually Withdraw Energy) became effective November 10, 2008 and forward, which required some resettlement.

RSG Under ASM: In the December 12, 2008 ASM clean-up filing, MISO added parenthetical language that explicitly stated it subjects to real-time RSG charges only those Resource Deviations "(not otherwise exempt from hourly Excessive Energy Calculations and Excessive/Deficient Energy Deployment Charges pursuant to Section 40.3.4d)". On August 7, 2009, FERC indicated the Midwest ISO's proposed exemptions from RSG charges may be unjust and therefore FERC made the tariffs effective January 6, 2009, subject to refund and further Commission order (P. 50). The RSG Task Force (RSGTF) has been meeting frequently as a result of the FERC August 7, 2009 order. At the RSGTF's request, MISO requested and was granted a 30-day extension by FERC to December 7, 2009. Dr. Patton is performing a RSG Cost Attribution Study and has presented an initial draft report to the RSGTF. The updated study will be posted on November 5, 2009, and discussed at the November 9, 2009 RSGTF conference call meeting. A ballot has been prepared, posted with the November 2, 2009 RSGTF meeting materials, and is due on November 13, 2009.

RSG Redesign: On February 23, 2009, MISO filed proposed tariff revisions setting forth a redesigned framework for the allocation of RSG costs (RSG Redesign). FERC has not yet acted on this filing.

Status: Continue monitoring.

3. Market Monitoring, Market Power Mitigation, and OMS calls with MISO IMM

On 10/27, we sent a letter to Dr. David Patton regarding his third quarterly report to FERC (filed on 10/7) on the applicable threshold for economic withholding in MISO's ASM docket ER07-1372. In that report, the IMM found no mitigation of ASM and very little evidence exercise of market power, thus allowing the threshold to go up another $10 to $40/MW effective 10/1/09. The report included a table that showed results of the MWs that failed at the $10, $20, and $30 adders. Several fellow group members recommended that OMS contact the IMM and urge the continued reporting of this table. We discussed this on 10/8 with the OMS Board, who approved our work group sending an e-mail to Dr. Patton. We then prepared a letter that Bill Smith e-mailed to David Patton. The letter is attached hereto.

At the 8/18 OMS Sector meeting with MISO management, MISO offered to provide a day-in-the-life discussion with OMS, suggesting, for example, a walk though of the automatic mitigation process.

Bob Pauley and Nick Bowden coordinate communications and meetings with the IMM for the M&TWG.

Status: Bill Smith to coordinate a meeting with MISO for all OMS interested in the mitigation process.

4. Scarcity pricing events

At the 10/6 MISO MSC meeting, MISO reported pricing events and a software problem related to ex post operating reserves and the use of OR demand curves to set prices on 9/12 and 13. MISO's software does not reduce the contingency reserve requirement during CR deployment, so the 9/12 even was in error. MISO developed a workaround and plans a software fix by next month. MISO gave an update during the 11/3 MSC meeting where stakeholders also discussed problems on 9/30 and 10/5. Stakeholders raised more general concerns about the demand curves with Bill Smith on 10/26. Bill passed it on to our work group.

Status: Expect to share stakeholder general concerns with work group via e-mail and a possible work group conference call.

Notice of other related items:

5. **MISO Market Subcommittee** - monthly, meetings 11/6, 12/1
Jeff Kaman helps provide highlights for our group

6. **FERC Market Oversight Calls** - monthly, 11/24 3:00 PM EST

The **OMS Markets and Tariffs Work Group** covers: ASM, Day2, FTR, ARR, RSG, LTTR, Market Monitoring and Mitigation. See
http://www.misostates.org/2008Oct14OMSWGstructureapprovedbyOMSBOD.pdf

Christine Ericson and Bill Bokram, Markets and Tariffs Work Group co-chairs

From:	Julie Mitchell [Julie@misostates.org]
Sent:	Wednesday, October 28, 2009 10:12 AM
To:	Bill Smith; Illinois- Sherman Elliott ; Jim Atterholt - Indiana; Kentucky - David Armstrong; Manitoba - Graham Lane; Martinez, Monica (DELEG); Minnesota - Tom Pugh; Missouri -Jeff Davis; Montana - Greg Jergeson; ND - Tony Clark ; Ohio - Valerie Lemmie ; PA - Tyrone J. Christy ; Rob Berntsen - Iowa; South Dakota - Gary Hanson; Wisconsin - Lauren Azar
Cc:	Alicia Allen; Bill Bowker - KY; Billie Ramsey (T Christy); Brenda Howe; Brendah Stith ; Brian DeKiep ; Brian Rybarik - WI ; Burl Haar (T. Pugh); Carrie Sheriff ; Charlene A. Magstadt (T. Clark); Demaris Axthelm (G. Hanson); Vallance, Erika (DELEG); Gerry Gaudreau; Greg Rislov - SD; Gregory, Sheryl; Jeff Johnson; Jeff Kaman ; Jim Melia - PA; Judi Brooks (R. Bernsten); Judy Scheier; Krystal Jones (L.Azar); Pappas, Lisa (DELEG); Mary Swoboda (T. Pugh); Quanetta Batts; Randy Pilo; Rolayne Wiest ; Ronnie Slager (D.Boyd); Thomas Lindgren; Butcher, Angela (DELEG); Barb Oswalt; Beth Roads; Bokram, William (DELEG); Bill Smith; Bill VanderLaan ; Bob Pauley - IN; Brad Borum ; Brian Rounds ; Chancy Bittner; Christine Ericson; Dan Fritz; Dan Johnson ; Daniel Shields; Dave Johnston ; David Wang; Dennis Koepke ; Don Howard ; Don Neumeyer ; Frank Bodine ; Fred Heizer; Greg Scheck ; Hisham Choueiki; Jack Dwyer; James Wottreng; Jason Cross; Jerry R. Lein; Jim Busch; Jim Sundermeyer; Jon Whitis; Jorge Valladares; Kim Wissman; Mark Hanson ; Mike Proctor ; Nancy Campbell ; Nick Bowden; Parveen Baig - IA; Randy Rismiller; Robert Endris ; Robert Mork; Samir Ouanes; Sheila Parker ; Steve Dottheim; Paytash, Stephen (DELEG); Vernon Jordan; Julie Mitchell
Subject:	Memo to OMS BOD on LTTR issue
Attachments:	Memo - Obtaining Long Term Congestion Protection for New Baseload Resour_3.pdf; LTTRs Presentation_20090821.pptx

Sent on behalf of Christine Ericson and Bill Bokram

Dear OMS Board,
Per your request, the M&TWG has looked into the question of long term transmission rights within the Midwest ISO.

> **RECOMMENDATION**
> The M&TWG recommends to the OMS Board that it find that this LTTR issue merits attention and direct the M&TWG to monitor the issue through the appropriate MISO stakeholder groups and to ask MISO to provide any further information regarding the concerns raised and expected priority so that we can better assess and monitor the problem and report further findings to the Board.

The M&TWG met on Wednesday 10/21 to discuss long-term transmission rights with Mike Stuart of WPPI Energy.

He explained that an issue has been identified in the Midwest ISO regarding difficulties obtaining long term congestion protection for new baseload resources during the Stage 1A process of LTTR allocation. We received the attached memo and presentation from him detailing the particulars of the issue. He said that the problem should be addressed in order to keep retail rates reasonable, that this is not just an aberration, but a long-term problem that could negatively impact consumers.

Mike indicated that there are some apparent modeling flaws that are showing up particularly at the flow gates between PJM and MISO. It seems that capacity is being assigned to loop flows, resulting in PJM flows getting priority over new MISO baseload generation. In addition, transmission upgrades are going into the model at different times than (a year prior to) new baseload resources, resulting in new generation not going in until the end of Stage 1A. He suggests that this timing differential needs to be synched up. He clarified that all owners of new baseload generation, including those that do not serve load, should be able to obtain congestion protection.

When asked about the potential fixes to this problem, he acknowledged that such fixes would likely come at the expense of capacity in Stage 1B of allocation process, as well as those purchasing FTRs in the auctions. Possible push back to changes may come from participants in those auctions, as well as other load serving entities.

When asked about the potential for FTR underfunding, he said that it was a mistake to over-emphasize underfunding. He believes that, from an LSE stand point, getting the FTR is more important than underfunding. He considers this problem top priority for LSEs.

Regarding further actions, those looking for solutions are asking MISO to make this issue a high priority and to do some analysis and provide a solution. They anticipate this being an agenda item in the FTR WG and MSC in the coming months and would like to see the Midwest ISO make a FERC filing by mid 2010 so that the changes can go into effect for 2011.

The M&TWG discussed the concerns and believe that the issue merits looking into. However, additional information is needed to fully assess and take a specific position on the issue. We do not know, for example, if MISO shares the same sense of urgency for resolving this issue. We shared a summary and recommended actions with the group via e-mail on 10/21. Our recommendation is a work group product.

Thank you to for your attention to this matter.

Christine Ericson and Bill Bokram, Markets & Tariffs Work Group co-chairs

Cc: M&TWG

Attachments:
Memo - Obtaining Long Term Congestion Protection for New Baseload Resour_3.pdf
LTTRs Presentation_20090821.pptx

1425 Corporate Center Drive
Sun Prairie, WI 53590
P: 608.834.4500 F: 608.837.0274
www.wppienergy.org

MEMORANDUM

TO: Christine Ericson

FROM: WPPI Energy

DATE: October 16, 2009

SUBJECT: **Obtaining Long Term Congestion Protection for New Baseload Resources**

This memo highlights a problem obtaining long term congestion protection for new baseload resources. This issue has been raised by a group of LSEs privately with the Midwest ISO's senior management, at the MSC, and at the FTR work group. In an effort to make the issue understandable, I will try to explain the problem in plain English.

The federal statute that requires the Midwest ISO to provide long term transmission rights (LTTRs) states that the protection applies to both "existing and planned" resources. The Midwest ISO's regime protected the then-existing (based upon a historical year) baseload resources by allowing load serving entities (LSEs) to include baseload units in their base set of resources that qualify for LTTRs.

The Midwest ISO's rules also established a procedure for adding (or substituting) new baseload resources to the LSEs' base set. The procedure allows the LSEs to seek to add a new baseload resource to the base set after the end of the initial stage of the annual allocation process. At that point, the Midwest ISO's model includes 100% of the transmission assets and generation assets that serve no more than one-half of the peak load. In developing the rules, we assumed the model would contain sufficient capacity at the end of the initial stage of the annual process to allow an LSE to add a significant share of a new baseload resource to its base set without creating a transmission overload.

Contrary to this assumption, we understand that every request to add a new resource to an LSE's base set has been denied. This creates a very significant delivered prices risk for any LSE that is or plans to add baseload resources to their generation portfolio.

A number of known factors (and perhaps some unknown ones) contribute to the problem. They include:

1. There may be an issue concerning the Midwest ISO's transmission model topology and/or modeling of third party loop flows since the model overloads with only the Midwest ISO generation assets capable of serving 50% of the peak load included in the Midwest ISO model.

2. Most baseload resources qualify as network resources contingent on transmission upgrades made in conjunction with the construction of the generating resource. The new generating resources often do not get the benefit of the transmission upgrades. This transmission capacity is available in the model to all others, and is not set aside for the new generation for which the upgrades were constructed.

3. Most of us assumed that to place a new baseload resource into the base set, an LSE would need to remove some number of MWs from their base set to stay within the “50% of peak” requirement applicable to the initial stage of the annual allocation. As structured, the Midwest ISO’s rules create a very unfavorable risk/reward profile for the LSE for the following reason. The LSE first must designate how many MWs it desires to remove from its historical base set and confirm the removal of those MWs prior to the initial stage of the allocation process. The confirmation automatically causes the LSE to lose LTTRs protection for these MWs. The loss is complete before the LSE knows if it will obtain any LTTR protection for its new baseload resource, since the LSE cannot request LTTRs for the new resource until after the end of the initial stage. The LSE is placed in the untenable position of surrendering LTTRs it had previously been granted in exchange for a right to seek LTTRs for its new baseload resource, without <u>any</u> assurance that any LTTRs associated with the new resource will be granted. **[Note: The Midwest ISO recently told a group of us that this point is not accurate and promised to share exactly how it will administer the process.]**

We believe the issue that currently affects a number of LSEs with new baseload resources coming on line soon and will affect many others in the future.

Long-Term Transmission Rights (LTTR)

The Issue

- EPAct 2005 requires long term transmission rights (LTTRs) for “existing or planned” resources.
- Midwest ISO’s regime provides such protection in theory.
- In practice, the regime makes it extremely difficult to add a new baseload resource to the base set.

Background

- LTTR rules allowed LSEs to include then-existing (i.e., 2004 in-service) baseload units in base set of resources.
- Rules also establish a procedure for adding new resources to LSEs' base set.
- LSEs may seek to add new resource to its base (LTTR) set in the annual allocation process.
- Requested additions will not be granted if adding a new resource exacerbates binding constraints in Stage 1A with a sensitivity above the *de minimis* level of 0.1%.
- While there have been only a limited number of requests, it appears that to date every request to add a new resource to LSEs' base set has been denied. Review of the SFT at end of Stage 1A strongly suggests an ongoing problem.

Contributing Factors

- The SFT model includes a number of assumptions that restrict granting LTTRs.
- New resources do not get the benefit of transmission upgrades made in conjunction with the construction of the new resource.
- To add a new resource at the present time, LSE must irrevocably sacrifice MWs in existing historical base set in excess of 115% of Baseload Usage (57.5% of forecast peak demand). This step must be taken in conjunction with the new RSP request and without any assurance that request to add new resource will be granted.

Incremental Improvements Considered at FTR Workgroup

- FTR workgroup has indicated its support for certain incremental improvements, including:
  - o Increasing the impact sensitivity threshold from 0.1% to 1%.
  - o Modifying the process to allow a party to specify, in advance, the minimum Added/Relinquished ratio of ARRs they are willing to accept when seeking to add the base set.
- These provisions may improve, but are unlikely to solve, the situation.
- Additional analysis of the problem is necessary.

Requested Action

- Direct the appropriate stakeholder group in conjunction with the Midwest ISO to:
  - o Give priority consideration to this issue.
  - o Determine factors that cause/contribute to inability to obtain LTTRs for new resources.
  - o Identify proposed solutions and the pros and cons of each proposed solution.
- Recommend appropriate action.

Sponsoring Entities

- American Municipal Power Inc.
- Consumers Energy
- Illinois Municipal Electric Agency
- Indiana Municipal Power Agency
- Integrys
- Madison Gas & Electric
- Missouri River Energy Services
- Missouri Joint Municipal Electric Utility Commission
- We Energies
- WPPI Energy

Update on the Real-Time Revenue Sufficiency Guarantee (RSG) Cost Allocation Issues – November 2, 2009

The purpose of this report is to update the OMS Board on recent developments in the RSG proceedings before FERC.

To ensure that adequate supply is available to meet real-time demand, resources that are made available as a result of the Reliability Assessment Commitment (RAC) process receive compensation at least equal to their start-up offers, no-load offers, and incremental energy costs, even if the resources are not dispatched. When real-time Locational Marginal Prices (LMP) are not sufficient to fully compensate resources to this minimum reimbursement level, they receive a real-time Revenue Sufficiency Guarantee (RSG) make whole payment for the shortfall. The real-time RSG make whole payments are funded primarily by RSG charges for realtime deviations from day-ahead schedules.

1. Summary

RSG Resettlement: In the June 12, 2009 Order, FERC used its discretion to waive refunds prior to November 5, 2007. As a result, RSG resettlement was required to fix the Rate Mismatch from November 5, 2007 through November 9, 2008 and the RSG Interim Rate method (removal of the RSG exemption if do not Actually Withdraw Energy) became effective November 10, 2008 and forward, which required some resettlement.

RSG Under ASM: In the December 12, 2008 ASM clean-up filing, MISO added parenthetical language that explicitly stated it subjects to real-time RSG charges only those Resource Deviations"(not otherwise exempt from hourly Excessive Energy Calculations and Excessive/Deficient Energy Deployment Charges pursuant to Section 40.3.4d)". On August 7, 2009, FERC indicated the Midwest ISO's proposed exemptions from RSG charges may be unjust and therefore FERC made the tariffs effective January 6, 2009, subject to refund and further Commission order (P. 50). The RSG Task Force (RSGTF) has been meeting frequently as a result of the FERC August 7, 2009 order. At the RSGTF's request, MISO requested and was granted a 30-day extension by FERC to December 7, 2009. Dr. Patton is performing a RSG Cost Attribution Study and has presented an initial draft report to the RSGTF. The updated study will be posted on November 5, 2009, and discussed at the November 9, 2009 RSGTF conference call meeting. A ballot has been prepared, posted with the November 2, 2009 RSGTF meeting materials, and is due on November 13, 2009.

RSG Redesign: On February 23, 2009, MISO filed proposed tariff revisions setting forth a redesigned framework for the allocation of RSG costs (RSG Redesign). FERC has not yet acted on this filing.

2. Historical Background

RSG, Prior to August 10, 2007 (Docket ER04-691)

At the start of the energy-only market, April 1, 2005, MISO did not charge Virtual Supply Offers (VSOs) for RSG costs, though the tariff required it. FERC waived the charge to VSOs for RSG costs for the period prior to April 25, 2006. MISO proposed to exempt VSOs from RSG, but FERC rejected the proposal. On October 26, 2006, the Commission reaffirmed its determination that virtual supply offers accepted in the day-ahead market can require the commitment of physical resources in the RAC process, which may cause RSG costs to be incurred.[1] To ensure that cost responsibility follows cost incurrence, the Commission required the Midwest ISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs they cause.[2] MISO then proposed a net approach where VSOs could be netted against Virtual Demand Bids.

On March 17, 2007, FERC rejected the net virtual proposal. In addition, FERC stated that all VSO volumes should be used to determine the RSG rate, but only participants that physically withdraw energy would have their VSO volumes subject to the RSG charge. This determination created differing rate treatments for VSOs and also created a RSG rate and charge mismatch.

Subsequently, MISO determined that the effect of developing an RSG rate based on volumes that would not then be subject to the RSG charge would shift approximately 57 percent of the RSG costs to Revenue Neutrality Uplift (RNU) where it would be collected from market participants based on load ratio share. The estimated real-time RSG cost from market start through February 2007 totaled almost three quarters of a billion dollars.[3]

On November 5, 2007, in the Order on Compliance Filing, FERC directed MISO to submit an additional compliance filing within 30 days. In addition, FERC indicated that there should be no volume mismatch between the RSG charge and the RSG rate.[4]

On December 5 2007, MISO made its compliance filing. In it, MISO discussed the conflicting language of the FERC orders and alerted all parties that since initiating resettlement it had consistently calculated the RSG rate based on all VSOs and not just those VSOs associated with actual withdrawals of energy.[5]

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[1] *Midwest Independent Transmission System Operator, Inc.*, 117 ¶ 61,113 (2006) (RSG Rehearing Order) at P 108.

[2] RSG Rehearing Order at P. 117.

[3] Protest of OMS, Docket ER04-691-089, December 19, 2007, p. 3.

[4] *Midwest Independent Transmission System Operator, Inc.*, 121 ¶ 61,132 (2007) (Order on Compliance Filing)at P 23 and 26.

[5] Compliance Filing of Midwest Independent Transmission System Operator, Docket ER04-691-089, December 5, 2007, p. 2 – 3.

On December 19, 2007, OMS filed a protest. OMS stated that the MISO compliance filing did not comply with FERC's order with respect to RSG rate and charge calculations and resulted in RSG costs not being assigned to cost causers but instead being uplifted to load. OMS requested that FERC reject the filing, direct MISO to modify its tariff provisions, and resettle the market consistent with FERC's order.[6]

On November 7, 2008, in Dockets ER04-691-088 and -089, FERC issued an Order on Rehearing and Compliance Filing accepting in part and rejecting in part the MISO December 5, 2007 compliance filing. In it FERC stated there should be no mismatch, that the virtual supply offers of participants that withdraw energy which are subject to the RSG charge should sum to the virtual supply offers used in developing the RSG rate, and that to the extent that MISO has settled customer bills on a different basis, refunds are required back to April 25, 2006 (P. 30 and 56).

On December 8, 2008, MISO submitted its RSG compliance filing in docket ER04-691 (for the period prior to August 10, 2007). In it, MISO stated that though the November 7 Order did not specifically state that the refunds should be with interest, it intended to include interest on resettlements, consistent with the requirements of the Commission's previous RSG refund directives that granted interest.[7] MISO also stated it believed the November 7 Order's no-mismatch interpretation warranted resettlement of RSG prior to April 25, 2006, and MISO would therefore resettle that period as well.[8] A request for clarification was sought of FERC on; (1) whether resettlement should extend to the period 4/1/05 through 4/24/06 as MISO had interpreted, and (2) whether interest is applicable to the period 4/1/05 through 8/9/07 as MISO had assumed.

On June 12, 2009, FERC issued an Order Dismissing Rehearing Requests, Waiving Refunds and Providing Guidance. In this order, FERC:

1. Dismissed requests for rehearing of the Fourth Rehearing Order, the November 7, 2008 order (Order point A).
2. Used its discretion to waive refunds prior to November 5, 2007 (P 41, Order point B)
3. Refunds are required starting on November 5, 2007 (P 42).
4. Interest applies to the refunds (P 42)

Though some argued that the Rate Mismatch should be eliminated back to the start of the market (April 1, 2005), FERC recognized that its Second Rehearing Order error led parties to believe

[6] Protest of OMS, Docket ER04-691-089, December 19, 2007, p. 4 and 5.

[7] Compliance Filing of Midwest Independent Transmission System Operator, Docket ER04-691-88 and -89, December 8, 2008, p. 4.

[8] Compliance Filing of Midwest Independent Transmission System Operator, Docket ER04-691-88 and -89, December 8, 2008, p. 8.

that rate mismatch was acceptable. It wasn't until the Second Compliance Order, issued on November 5, 2007, that FERC addressed the rate mismatch issue comprehensively (P 41).[9]

On August 10, 2009, FERC issued an Order Granting Rehearing For Further Consideration of its June 12, 2009 Order.

RSG, August 10, 2007 to January 5, 2009 (Dockets EL07-86, EL07-88, and EL07-92)

In August 2007, Ameren and others filed section 206 complaints regarding the differing cost treatment for identical transactions and the significant uplift being caused by the RSG rate and charge mismatch.

In September 2008, Complainants filed Briefs under the paper hearing process. On October 10, 2008, the OMS filed a reply brief in support requesting that the Commission remove the reference to "actually withdraws Energy" from the tariff and require refunds back to August 10, 2007.[10]

On November 10, 2008, in Docket Numbers EL07-86-000, EL07-88-000, and EL07-92-000, FERC issued an Order on Paper Hearing on the RSG complaints. In it FERC determined that (1) the current rate is unjust and unreasonable, (2) the cost allocation proposal that eliminates the "actually withdraws energy" language is a just and reasonable basis for RSG cost allocation, (3) refunds with interest from August 10, 2007 are required, and (4) a compliance filing from MISO within 30 days is required. In addition, FERC found that the MISO "indicative" tariff sheets (aka the RSG Redesign proposal) also provided a just and reasonable basis for future cost allocation. Since MISO needed time to conform the proposal to the Ancillary Services Markets tariff, FERC allowed MISO to file its indicative allocation when it had a complete and final proposal. FERC also encouraged MISO and stakeholders to continue to address software and market design issues to ensure RSG charges are minimized to the extent possible (P. 118). (OMS filed comments on the RSG Redesign in this docket on March 24, 2008.)

On December 10, 2008, MISO submitted its RSG compliance filing in dockets EL07-86, -88, and -92 (for the prospective period beginning on August 10, 2007).

On February 24, 2009, the Independent Market Monitor (IMM) filed Findings and Recommendations related to the November 10, 2008 Order on Paper Hearing. In it, the IMM recommended that the Commission reconsider the determinations made in the Order on Paper Hearing. The IMM's main findings were:

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[9] *Midwest Independent Transmission System Operator, Inc.*, 121 ¶ 61,241 (2009) (Order Dismissing Rehearing Requests, Waiving Refunds, and Providing Guidance)

[10] In its Reply Brief, the OMS also encouraged and reminded FERC to address the period prior to August 10, 2007. FERC addressed this period in the Order on Rehearing and Compliance Filing issued on November 7, 2008, in Dockets ER04-691-088 and -089.

a. The Interim RSG Method over-allocates RSG costs to real-time deviations, which includes virtual supply offers.
b. Resettlements will allocate such a large share of RSG costs to virtual suppliers that it will likely result in defaults and provide a significant disincentive to on-going participation by virtual suppliers.
c. Evidence in January suggests that price convergence is already suffering.
d. The pre-existing cost allocation method is more closely aligned with actual cost causation than the replacement cost allocation.
e. The RSG Redesign would provide a framework for a remedy.

Answers were filed by MISO and others regarding some of the IMM findings (particularly c, d, and e). MISO reminded FERC that the Redesign has limitations that preclude its retroactive application (the unavailability of the historical data needed for such a retroactive application)

On June 12, 2009, FERC issued an Order Dismissing Rehearing Requests, Waiving Refunds and Providing Guidance on June 12, 2009. In this order, FERC:

1. Dismissed requests for rehearing of the Fourth Rehearing Order, the November 7, 2008 order (Order point A).
2. Used its discretion to waive refunds prior to November 5, 2007 (P 41, Order point B)
3. Refunds are required starting on November 5, 2007 (P 42).
4. Interest applies to the refunds (P 42)

Though some argued that the Rate Mismatch should be eliminated back to the start of the market (April 1, 2005), FERC recognized that its Second Rehearing Order error led parties to believe that rate mismatch was acceptable. It wasn't until the Second Compliance Order, issued on November 5, 2007, that FERC addressed the rate mismatch issue comprehensively (P 41). [11]

On August 10, 2009, FERC issued an Order Granting Rehearing For Further Consideration of its June 12, 2009 Order.

RSG, January 6, 2009 and forward until the RSG Redesign (Docket ER09-411-000)

In the December 12, 2008 ASM clean-up filing, MISO added parenthetical language that explicitly stated it subjects to real-time RSG charges only those Resource Deviations "(not otherwise exempt from hourly Excessive Energy Calculations and Excessive/Deficient Energy Deployment Charges pursuant to Section 40.3.4d)" (MISO 12/12/08 filing,p.4-5, tariff sheet no. 1096) Motions to intervene and protests were submitted.

The exemption would apply to the following resources: (1) resources following Midwest ISO directives; (2) resources in test mode, start-up or shut down mode; (3) resources that trip and go offline; (4) resources involved in a contingency reserve deployment; (5) resources covered by the

[11] *Midwest Independent Transmission System Operator, Inc.*, 121 ¶ 61,241 (2009) (Order Dismissing Rehearing Requests, Waiving Refunds, and Providing Guidance)

deactivation of dispatch band option; (6) resources affected by other events or conditions beyond their control; and (7) intermittent resources. (FERC Order in docket ER09-411-000, August, 7, 2009, P.3)

On, February 9, 2009, FERC staff requested additional information regarding each exemption, including the policy basis and cost causation analysis. MISO responded on March 11, 2009 (P.7)

On May 8, 2009, FERC staff requested additional information including (1) a detailed description of how the Midwest ISO forecasts, schedules, and dispatches for intermittent and other resources that are exempt from real-time Revenue Sufficiency Guarantee charges under the proposal; and (2) a detailed description of how the Midwest ISO determines the amount of headroom needed for intermittent and other resources that are exempt from real-time Revenue Sufficiency Guarantee charges under the proposal. MISO responded on June 8, 2009. (P. 9)

On August 7, 2009, in docket ER09-411-000, FERC issued an Order Accepting and Suspending Tariff Sheets Subject to Refund In Part and Conditionally Accepting Tariff Sheets in Part. With respect to the proposed exemptions FERC determined:

> Our review of the record in this proceeding indicates that the Midwest ISO's proposed exemptions from Revenue Sufficiency Guarantee charges have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Therefore, we will accept the Midwest ISO's proposed revisions for filing, suspend them and make them effective January 6, 2009, subject to refund and further Commission order. (P. 50)
>
> We direct the Midwest ISO to submit to the Commission a filing within 30 days of the date of this order a proposed plan and timeline for the RSG Task Force to perform an analysis that considers and addresses, among other things that the RSG Task Force deems relevant: (1) the types of and characteristics of all resources that contribute to real-time Revenue Sufficiency Guarantee costs, as well as how such resources cause real-time Revenue Sufficiency Guarantee costs to be incurred; (2) the operation of the regulation and contingency reserve markets when accounting for real-time resource deviations and the interplay between such markets and the incurrence of real-time RSG costs; and (3) the operational, dispatch, and reliability rules and parameters that may be impacting the level of real-time Revenue Sufficiency Guarantee costs, including forecasting methods and headroom commitments. To the extent that the analysis of the RSG Task Force is expected to result in future revisions to the allocation of Revenue Sufficiency Guarantee charges, we direct the Midwest ISO to specify milestones for software development and expected implementation dates in this compliance filing. (P. 51)
>
> The Commission directs the Midwest ISO to submit a further compliance filing within 90 days of the date of this order providing further support for its proposed exemptions from real-time Revenue Sufficiency Guarantee charges based on the findings and

> recommendations of the RSG Task Force or, as appropriate, amending its proposal based on the findings and recommendations of the RSG Task Force. (p. 51)

The RSGTF has been meeting frequently as a result of the FERC August 7, 2009 order. At the RSGTF's request, MISO requested and was granted a 30-day extension by FERC to December 7, 2009. Dr. Patton is performing a RSG Cost Attribution Study and has presented an initial draft report to the RSGTF. The updated study will be posted on November 5, 2009, and discussed at the November 9, 2009 RSGTF conference call meeting. A ballot has been prepared, posted with the November 2, 2009 RSGTF meeting materials, and is due on November 13, 2009.

RSG Redesign, pending before FERC (Dockets EL07-86, EL07-88, and EL07-92)

On February 23, 2009, in further compliance with the November 10, 2008 Order on Paper Hearing, MISO filed proposed tariff revisions setting forth a redesigned framework for the allocation of RSG costs (RSG Redesign).[12] Describing the proposed framework, MISO stated:

> In particular, the Redesign Proposal enhances the tracking of cost causation by basing the calculation and allocation of RSG costs on three major reasons for the commitment of units in the RAC process: (1) to manage a transmission constraint or to address a local reliability concern; (2) to address the need for Headroom; and (3) to adjust to deviations from Day-Ahead Schedules. In addition, the Redesign Proposal allows Market Participants to net certain deviations when they provide the Midwest ISO sufficient advance notice of anticipated schedule changes, thereby avoiding the need for additional commitments in the RAC process. Lastly, the Redesign Proposal allocates RSG costs to all Market Participants pro rata based on their Market Load Ratio Share (also operationally described by the Midwest ISO as the "Second Pass" RSG allocation), to the extent such costs are not directly attributable on a cost-causation basis to the specific factors described above.[13]

On March 16, 2009, the comment due date, various Protests and Comments on the RSG Redesign proposal were filed.

Jim Wottreng, on behalf of the OMS Markets and Tariffs Work Group

[12] Compliance Filing of the Midwest Independent Transmission System Operator, Inc. re Redesign of Revenue Sufficiency Guarantees Docket Nos. EL07-86-008, EL07-88-008, and EL07-92-008, February 23, 2009.

[13] Compliance Filing of the Midwest Independent Transmission System Operator, Inc. re Redesign of Revenue Sufficiency Guarantees Docket Nos. EL07-86-008, EL07-88-008, and EL07-92-008, February 23, 2009, p. 6 - 7.

OMS
Organization of MISO States

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October 27, 2009

VIA Electronic Mail

Dr. David Patton
Potomac Economics Ltd.
9990 Fairfax Boulevard, Ste. 560
Fairfax, Virginia 22030

Re: OMS Recommendation that conduct results associated with a $10, $20, $30, $40, and $50 adders (if and when the $50 becomes applicable) will continue to be reported quarterly by the IMM for the regulation and spinning reserve products

Dear Dr. Patton,

The OMS Markets and Tariff Work Group (M&TWG) is charged with monitoring the Midwest ISO market design and accompanying tariff provisions to assess whether the Midwest ISO is delivering efficient results, and to recommend actions where the Midwest ISO could improve in that regard. We are writing with respect to the IMM's October 7th report regarding the increases to the ancillary services conduct thresholds that have or will be implemented. (FERC Docket No. ER07-1372) As evident in your October 7th report, increasing the thresholds decreases the likelihood that increases in ancillary services bids will fail the conduct portion of the monitoring and mitigation protocol. The M&TWG cautions that this increases the ability for market power exertion to evade detection and affect prices for ancillary services.

While FERC has approved a process that allows the increases to the conduct threshold carried out by the IMM, the OMS M&TWG remains concerned about the potential for exercising market power in the ancillary services market. Although the OMS board has not adopted the conduct and impact test as an effective method for market power mitigation, the OMS M&TWG has found the tables concerning bid data and threshold violations which accompanied the IMM's validation of market competitiveness to be a good indicator of market behavior. The OMS M&TWG, therefore, recommends that the conduct results associated with a $10, $20, $30, $40, and $50 adders (if and when the $50 becomes applicable) continue to be reported quarterly by the IMM for the regulation and spinning reserve products. The inclusion of this data will be useful for regulators assessing the competitiveness of the ancillary services market, while also serving to mitigate anticompetitive behavior through the threat of public scrutiny. Additionally, it would be informative to see the number and percentage of failures at even lower thresholds.

We discussed this with the OMS Board of Directors during their meeting on October 8, 2009 and received their approval to send this request and report the results back at a future Board meeting. Please confirm that you will adopt our recommendation and that the information referenced above will continue to be forthcoming.

Thank you for your attention to this matter.

Sincerely,

Bill Bokram, Christine Ericson, M&TWG Co-Chairs,
and Nick Bowden, M&TWG Market Monitoring Subcommittee Co-Chair

cc: Bill Smith, David Hadley

Long-Term Transmission Rights (LTTR)

The Issue

- EPAct 2005 requires long term transmission rights (LTTRs) for “existing or planned” resources.
- Midwest ISO’s regime provides such protection in theory.
- In practice, the regime makes it extremely difficult to add a new baseload resource to the base set.

Background

- LTTR rules allowed LSEs to include then-existing (i.e., 2004 in-service) baseload units in base set of resources.
- Rules also establish a procedure for adding new resources to LSEs' base set.
- LSEs may seek to add new resource to its base (LTTR) set in the annual allocation process.
- Requested additions will not be granted if adding a new resource exacerbates binding constraints in Stage 1A with a sensitivity above the *de minimis* level of 0.1%.
- While there have been only a limited number of requests, it appears that to date every request to add a new resource to LSEs' base set has been denied. Review of the SFT at end of Stage 1A strongly suggests an ongoing problem.

Contributing Factors

- The SFT model includes a number of assumptions that restrict granting LTTRs.
- New resources do not get the benefit of transmission upgrades made in conjunction with the construction of the new resource.
- To add a new resource at the present time, LSE must irrevocably sacrifice MWs in existing historical base set in excess of 115% of Baseload Usage (57.5% of forecast peak demand). This step must be taken in conjunction with the new RSP request and without any assurance that request to add new resource will be granted.

Incremental Improvements Considered at FTR Workgroup

- FTR workgroup has indicated its support for certain incremental improvements, including:
  - Increasing the impact sensitivity threshold from 0.1% to 1%.
  - Modifying the process to allow a party to specify, in advance, the minimum Added/Relinquished ratio of ARRs they are willing to accept when seeking to add the base set.
- These provisions may improve, but are unlikely to solve, the situation.
- Additional analysis of the problem is necessary.

Requested Action

- Direct the appropriate stakeholder group in conjunction with the Midwest ISO to:
  - Give priority consideration to this issue.
  - Determine factors that cause/contribute to inability to obtain LTTRs for new resources.
  - Identify proposed solutions and the pros and cons of each proposed solution.
- Recommend appropriate action.

Sponsoring Entities

- American Municipal Power Inc.
- Consumers Energy
- Illinois Municipal Electric Agency
- Indiana Municipal Power Agency
- Integrys
- Madison Gas & Electric
- Missouri River Energy Services
- Missouri Joint Municipal Electric Utility Commission
- We Energies
- WPPI Energy

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Sun Prairie, WI 53590
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www.wppienergy.org

The way energy should be

MEMORANDUM

TO: Christine Ericson

FROM: WPPI Energy

DATE: October 16, 2009

SUBJECT: **Obtaining Long Term Congestion Protection for New Baseload Resources**

This memo highlights a problem obtaining long term congestion protection for new baseload resources. This issue has been raised by a group of LSEs privately with the Midwest ISO's senior management, at the MSC, and at the FTR work group. In an effort to make the issue understandable, I will try to explain the problem in plain English.

The federal statute that requires the Midwest ISO to provide long term transmission rights (LTTRs) states that the protection applies to both "existing and planned" resources. The Midwest ISO's regime protected the then-existing (based upon a historical year) baseload resources by allowing load serving entities (LSEs) to include baseload units in their base set of resources that qualify for LTTRs.

The Midwest ISO's rules also established a procedure for adding (or substituting) new baseload resources to the LSEs' base set. The procedure allows the LSEs to seek to add a new baseload resource to the base set after the end of the initial stage of the annual allocation process. At that point, the Midwest ISO's model includes 100% of the transmission assets and generation assets that serve no more than one-half of the peak load. In developing the rules, we assumed the model would contain sufficient capacity at the end of the initial stage of the annual process to allow an LSE to add a significant share of a new baseload resource to its base set without creating a transmission overload.

Contrary to this assumption, we understand that every request to add a new resource to an LSE's base set has been denied. This creates a very significant delivered prices risk for any LSE that is or plans to add baseload resources to their generation portfolio.

A number of known factors (and perhaps some unknown ones) contribute to the problem. They include:

1. There may be an issue concerning the Midwest ISO's transmission model topology and/or modeling of third party loop flows since the model overloads with only the Midwest ISO generation assets capable of serving 50% of the peak load included in the Midwest ISO model.

2. Most baseload resources qualify as network resources contingent on transmission upgrades made in conjunction with the construction of the generating resource. The new generating resources often do not get the benefit of the transmission upgrades. This transmission capacity is available in the model to all others, and is not set aside for the new generation for which the upgrades were constructed.

3. Most of us assumed that to place a new baseload resource into the base set, an LSE would need to remove some number of MWs from their base set to stay within the "50% of peak" requirement applicable to the initial stage of the annual allocation. As structured, the Midwest ISO's rules create a very unfavorable risk/reward profile for the LSE for the following reason. The LSE first must designate how many MWs it desires to remove from its historical base set and confirm the removal of those MWs prior to the initial stage of the allocation process. The confirmation automatically causes the LSE to lose LTTRs protection for these MWs. The loss is complete before the LSE knows if it will obtain any LTTR protection for its new baseload resource, since the LSE cannot request LTTRs for the new resource until after the end of the initial stage. The LSE is placed in the untenable position of surrendering LTTRs it had previously been granted in exchange for a right to seek LTTRs for its new baseload resource, without any assurance that any LTTRs associated with the new resource will be granted. **[Note: The Midwest ISO recently told a group of us that this point is not accurate and promised to share exactly how it will administer the process.]**

We believe the issue that currently affects a number of LSEs with new baseload resources coming on line soon and will affect many others in the future.

Report to the OMS Board
November 12, 2009

Modeling Workgroup mini-Report

(a) Value Proposition: The modeling workgroup had a conference call with MISO on November 4th to discuss the concerns and questions that were sent to MISO staff after the conclusion of the value proposition workshops in September and October. The discussion was quite informative, and MISO did a good job addressing our concerns and answering our detailed list of questions.

The major discussion points were

1) the newly introduced methodology for measuring reliability improvements,
2) the methodology for measuring improvements in dispatching efficiency, and
3) the methodology for estimating net savings due to capacity construction deferrals.

(b) Transmission Planner Position: A task force is currently compiling position descriptions for a Transmission Planner position to be hired by the OMS. We have received PD information from Transmission Owners, ISO's, and State Regulatory Agencies. Once we have a draft PD, we will circulate among the members of the task force. If OMS staffers are interested in being on this task force, please notify Bill and Hisham of your interest.

OMS Regional Planning Work Group
Report to OMS Board of Directors – November 12, 2009

FERC Request For Comments
The Regional Planning Workgroup and the Cost Allocation Workgroup worked together to draft a response to the FERC Request for Comments regarding transmission planning processes and cost allocation. The draft is currently before the OMS Board on today's meeting agenda.

New PAC Chair
Bob McKee took over as chair of the PAC starting in November 2009.

MTEP- 09
A PAC meeting was held in early October to finalize review and prepare comments on MTEP09. The PAC approved a motion to forward the MTEP09 report to the Advisory Committee and Board of Directors for approval. The Advisory Committee opted at its October meeting not to take a vote on MTEP09 and relied on the expertise of the PAC. The Midwest ISO Board is expected to vote whether to approve MTEP09 during its December meeting.

MTEP 09 contains 21 projects totaling $292 million that are eligible for cost sharing. Projects to be eligible for RECB base line reliability/GIP cost sharing include 3 projects in the east totaling approximately 88 million, four projects in the Central region totaling approximately $99 million and 13 projects in the west totaling approximately $108 million. Additionally, MTEP-09 includes the first regionally beneficial project with RECB II cost sharing. That project is P2794, a 345 kV tie line between the Coffeen and Coffeen North substations in south central Illinois.

MTEP-10
Proposed Scope of Work in 2010
Transmission solutions to address constraints not otherwise currently classified either as reliability or economic projects. Determine if the proposed solutions may have other reliability or economic benefits.

Potential new targeted studies include (1) planning for constraints resulting in LTTR infeasibility; (2) planning for constraints resulting in reduced deliverability of network resources; and (3) Southeast Wisconsin Issues Study.

Interconnection Process Task Force
The Midwest ISO Interconnection Process Task Force met August 27th in Carmel. The agenda included presentations on Injection/Withdrawal transmission rate design, temporaryGenerator Interconnection Agreement Limits and results of a survey seeking feedback on queue reform effectiveness.

Midwest ISO Studies are ongoing/done for ~37,500 MW of wind generation. Total RPS Mandates for Midwest ISO regions are ~ 23000 MW

The Midwest ISO plans to go forward with FLIP proposal starting with identification and subscription and continuing with proposal development beginning in October.

A workshop on the queue process was held on September 24 in Wisconsin. Next workshop is scheduled for November 12 in Saint Paul, Minn.

RGOS I
Purpose – To provide indicative transmission and generation to the regulatory community for input concerning the renewable zone strategy.

Status – Indicative costs ranging approximately $150 - $170 per MWh over the 15/25 GW and 345/765 kV scenarios have been released. Further studies including dynamic stability analysis and development of more accurate cost estimates for transformers/substations are underway.

RGOS II
RGOS II is designed to develop transmission alternatives needed to implement Renewable Portfolio Standards or goals at the least cost for consumers while continuing to reliably serve load.

In addition to the five RGOS I states, RGOS II covers Missouri, Illinois, Indiana, Michigan, Ohio and Pennsylvania. Any increases for RGOS I states will also be included.

Analysis will be performed in an open and transparent fashion involving stakeholders throughout, coordinate with neighboring systems.

The study is a Mid-term (5-15yr) bridge between the Generator Interconnection queue and longer term planning efforts.

RGOS II is a targeted study that is a coordinated effort within the Midwest ISO Transmission Expansion Plan (MTEP) "umbrella" that is intended to develop real projects.

Status: Indicative costs ranging from $80 Billion to $118 Billion over Local, Regional, RegionalOptimized, Combination and Combination 75/25 scenarios have been preliminarily identified.

EWITS Study Status & Schedule

Progress has been made in recent weeks towards successful completion of the Eastern Wind Integration and Transmission Study (EWITS, Phase I). The study team has been working hard to incorporate into the report the many excellent comments and recommendations from Technical Review Committee members in October. The final report will include updated scenarios of the future and Atlantic off-shore wind. The schedule has been adjusted to accommodate the suggestions for improvements.

In order to ensure a high quality final report, the public release of the EWITS report has been pushed back to mid-January (January 20th).

CARP - Injection/Withdrawal Methodology

The Midwest ISO recently had walk-through of a large spreadsheet prepared by Brattle Group that simulates the different possibilities for the injection/withdrawal methodology. The metrics include such items as: usage and access; local, sub-regional, and regional; generator and load, pricing zones, state footprints, etc. The OMS staff has just received a copy. The other Midwest ISO RECB stakeholders had their review November 9th.

OMS Resources Work Group

Status Report to OMS Board of Directors – November 12, 2009

1. LOLE 2010 Study Report

The 2010/11 planning year findings were released at the end of October.

- The Planning Reserve Margin (PRMsysingen) installed MISO generation stayed at 15.4% due equal off-setting effects. The EFORd's went up, but there less congestion and there was more utilization of external ties.
- The PRMlseigen for LSEs dropped from 12.69% to 11.94%. Besides the above effects, the load diversity factor changed from 2.35% to 3.00%. This is due to another year of data and shifting to a CP node basis.
- The PRMucap will drop from 5.35% to 4.50% for compliance. This is due to all the off-setting effects noted above.

2. Resource Compliance Template

Don Neumeyer sent out a survey to the States on the monthly compliance template reports, including the confidential state report on its content. He will follow up with individual calls.

3. Resource Adequacy Hot Topic

Resource Adequacy is the Hot Topic for December. The WG has responded and the responses are being compiled Nov 9th. They will be sent out immediately.

4. SAWG

Some of the other issues that are active include:

- LMR Deliverability – MISO has shown that some behind the meter generation and DR programs may not be deliverable to the MISO footprint due to local/sub-regional transmission constraints. They will study the system annually for an assessment
- Wind capacity credit for 2010/2011 – The LOLE WG is collecting comments about the probability distribution of wind during peak periods to determine. This will be reported to SAWG. That will report will be shared with stakeholders. That report will in turn will be shared with the Resources WG for comments.

5. LSE Under-Forecast Assessment

Below is a portion of the November report to SAWG:

S55 Data	June	July	August	June	July	August
	All	All	All	No RCS	No RCS	No RCS
Total Demand Forecasted (in MW)	91,682	108,086	106,355	N/A	N/A	N/A
Total Actual Demand (in MW)	95,186	84,421	93,865	N/A	N/A	N/A
# of CP nodes underforecasted (StDev and Losses included)	83	34	45	30	7	11
# of Market Participants that Underforecasted	45	29	32	15	5	10
# of CP nodes that reported StDev	127	159	159	N/A	N/A	N/A
# of CP nodes that reported Weather Normalization	4	N/A	N/A	N/A	N/A	N/A
Total CP nodes	264	264	264	134	134	134

Load nodes underforecasted in June, July, **and** August = 12
Load nodes underforecasted in two of the three months = 30

No RCS= does not include Retail Choice States IL, OH, MI
Weather normalized actual demand will be provided as soon as it becomes available

There was discussion about having some additional information on the distribution of the MW distribution in relationship to the # of CP nodes. Some small nodes could have under forecasting, but only a few MWs. So the cumulative risk is hard to assess. The issue of weather normalization for the whole LSE versus individual CP node was discussed. Then there was general mention of the recession continuing to impact sales. Another issue is how or not report non-jurisdictional LSEs to some states, yet they are in the planning pool which has potential impacts to the regulated LSE shedding non-firm and possibly firm load during Emergency Operating Procedures.

The SAWG would like some detailed feedback on the report from OMS:

- Granularity of reporting (LSE vs. Commercial Pricing Node)
- Reasonability band that could be applied to minimize reporting of under forecasts below a certain magnitude (identify gaming or situations that potentially harm reliability only)
- Feedback on Draft LSE Under Forecast Reporting template (attached)
- Should PRC designations be considered or should the two processes remain separate? (LSE over designates PRC to “hedge” under forecast)
- Under Forecast reporting of non-jurisdictional entities

6. Price Response Demand

At the October OMS Board meeting is was decided to leave the door open to further discussions on the use of PRD. The work effort will continue with the new OMS Demand Response WG. A contact is schedule with Dr. Patton to gain additional insight on his previous written comments on not sharing planning resources during emergency procedures. Also since the last discussion the final report a Demand Response Availability Data System was issued in September. That 67 page report does recognize PRD as real time pricing method in the non-dispatchable, time sensitive category just as Critical Peak Pricing, TOU, etc.

7. Volunteer Capacity Auction

Depending on one's view the activity is volatile or indicates that off-season months have much less value during a recession.

APRCs	Dec–09	Nov-09	Oct-09	Sep-09	Aug-09	Jul-09
Offers submitted	19,688.3	22,424.9	22,312.5	13,729.5	3,588	363.8
Bids submitted	1,226.0	1,038.6	614.9	300	110	1,216.6
Cleared Amount	1,226.0	1,038.6	614.9	300	110	363.8
Clearing Price	$0.75	$0.50	$0.05	$0.01	$1	$10,015

Midwest ISO
Energizing the Heartland

Midwest ISO Advisory Committee Conference Call
November 18, 2009
10:00am – 12:00pm EPT
Dial-in information available at www.midwestmarket.org

Agenda

1. Welcome*	Gary Mathis	10:00
2. Review of agenda	Gary Mathis	10:05
3. Approval of the October 2009 Meeting Minutes√	Gary Mathis	10:10
4. Action Items from previous AC Meetings	Alison Johnson	10:15
5. RSG Task Force Update	Jason Minalga	10:20
6. Advisory Committee Items	Gary Mathis	10:30
a. Self Assessment Discussion		
b. Hot Topics for 2010*		
c. Nominating Committee for 2010 AC Leadership*		
d. Alternate Dispute Resolution Committee (2 members)√		
e. Review AC Management Plan		
f. 2010 AC Meeting Schedule		
7. Standing Committee/Other Stakeholder Committee Reports		
a. RECB Task Force Update	Lauren Azar	10:50
b. Market Subcommittee Update	Barry Trayers	11:00
c. Reliability Subcommittee Update	Mike Zahorik	11:05
d. Planning Advisory Committee Update	Bob McKee	11:10
e. Finance Subcommittee Update*	Joe Buckley	11:15
f. Stakeholder Governance Working Group√	Bill SeDoris	11:20
g. Steering Committee*	David Hastings	11:30
h. Transmission Owners'*	JoAnn Thompson	11:35
i. Organization of Midwest ISO States	Bill Smith	11:40
8. New Business*	Gary Mathis	11:45
9. Recap – Issues/Assignments*	Alison Johnson	11:50

Rotating Agenda Team December: JoAnn Thompson
Brett Kruse
Jennifer Easler

Upcoming Hot Topics: December: Resource Adequacy
White Papers due Friday November 20

√ Denotes Potential Voting Item * Denotes Report is Oral

Midwest ISO
Energizing the Heartland

Midwest ISO Advisory Committee Meeting
October 14, 2009
10:00am – 3:10pm EPT
Dial-in and WebEx information available at www.midwestmarket.org

Minutes

1. **Welcome* (Gary Mathis)**

   Meeting called to order at 10:05 am ET.

   Members present:
   Chair: Gary Mathis
   Vice Chair: David Hastings
   Coordinating: *Alan Silk
   Environmental: John Moore
   Coop/Muni/TDU: Jim Keller, Steve Gaarde
   End User: Kevin Murray
   Public Consumer: Robb Mork
   Power Marketer: Joanne Borrell
   IPP: Mark Volpe, Marka Shaw, Ann Scott, Brett Kruse
   TO: Mal Bertsch, JoAnn Thompson, *Kevin Largura
   State Regulatory: Greg Jergeson, Bill Bowker, Valerie Lemmie
   ** denotes attendance via phone*

   All 9 members of the Board of Directors were present.

   FERC representatives present: Chris Miller, Patrick Clarey, Michael McLaughlin

   Mr. McLaughlin (Director of Office of Energy Market Regulation) discussed recent Midwest ISO accomplishments, such as the ASM launch, queue reform, wind energy integration and MidAmerica integration; he briefly touched on the "Otter Tail / MDU" filing currently pending with FERC, which they view with great importance. FERC's strategic plan may be found on their website, which guides their work with transmission planning, cost allocation, integration of renewable energy and demand response. The commission hopes to have participation by John Norris in the near future.

2. **Review of agenda (Gary Mathis)**
   No changes were made to the agenda.

3. **Approval of the September 2009 Meeting Minutes√ (Gary Mathis)**
   A motion to approve the minutes was moved by Jim Keller and seconded by David Hastings. Minutes were approved by voice vote.

4. **Action Items from previous AC Meetings (Alison Johnson)**
   All action items are closed.

5. **Sector Hot Topic – Regional Infrastructure Planning**
   Gary requested that Midwest ISO provide feedback at a future meeting on comments provided by sectors today. Full Hot Topic whitepapers and presentations may be found at:
   http://midwestmarket.org/publish/Document/6b6059_1239ec7b046_-75670a48324a?rev=5

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Midwest ISO Introduction (Jennifer Curran)
Jennifer overviewed the Midwest ISO transmission planning process and principles as provided with meeting materials. The MTEP report is a snapshot of all the various planning activities and studies, including projects recommended for immediate implementation.

a. Public Consumer Advocates (Robb Mork)
The sector has resource difficulties affecting their ability to participate in some stakeholder processes, but that isn't viewed as a fault of Midwest ISO; any ability to identify and bring issues to state regulators would be helpful. Midwest ISO has started working on improved forecasting with Module E; they have no further suggestions at this time but will monitor what moves through the stakeholder process. Congested flowgates are an issue that affects the community in general and work is needed to get new transmission built to resolve the issue. Some work is already underway. Midwest ISO could also be helpful in designing a transmission system that delivers the lowest cost power.

b. OMS (Valerie Lemmie)
Commissioner Lemmie commented that OMS has found Midwest ISO very responsive as they grapple with transmission planning and cost allocation issues. The Board of Directors did not have the whitepaper prior to the meeting, but the commissioner welcomed questions at any time in the future.

c. Environmental Sector (John Moore)
The sector feels that discussion and resolution of transmission planning and cost allocation need to go together. The number of subcommittees dealing with these issues makes it difficult for them to cover everything.

Director Evans asked about their suggestion for a biannual conference outside of the stakeholder process on transmission planning and related efforts Midwest ISO is involved with. John feels that this should include CARP, UMTDI, study updates, etc. focused on where the process is going for a broader audience.

d. IPP – PM (Mike Shields)
One focus in the paper touched on by Director Evans was the lack of an integrated regional resource planning process; the sector feels there may be areas where transmission is being planned that generation could be a better option. They would like to see Midwest ISO take a leadership role in identifying and sharing data, at least with states, in those areas where congestion points could be resolved.

Marka Shaw discussed potential solutions including a centralized capacity market, which would bring in the generation side, and centralized load forecasting.

RES Americas etc. (Richard Seide)
A written paper and Power Point were shared with the Advisory Committee. RES Americas sees mixed results from the planning process over the last year and commented on the positive and negative areas. Their recommendations are for Midwest ISO to assert leadership in regional and interconnection-wide planning efforts, managing political surrogates (such as Midwest Governors Association [MGA]), planning that recognizes beneficiaries over time and reduced uncertainty.

Director Feldman did not agree that Midwest ISO should take a position on public policy, but has a role to equip people with the right information to make decisions.

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Director Zeltmann responded to Richard's statement that there are no viable transmission expansion projects for wind outlet in Midwest ISO Transmission Expansion Plan (MTEP) MTEP 09, commenting that Clair Moeller and planning staff have looked at what generating facilities are available regardless of type of generation, ensuring it has the ability to get its product to market. Richard discussed queue mitigation proposals that aren't currently part of the process, and the need to address policy issues. Specifically, RES would like to see work from the Joint Coordinated System Plan (JCSP) and Regional Generation Outlet Study (RGOS) carried in and harvested in the form of actual projects. Richard stated that there was disparity between the process and outcome of the process. Director Evans reminded participants that the MTEP report is a snapshot at a point in time and urged patience.

LS Power (Terry Lane, Bryan Rushing)
LS Power is an IPP in the Midwest ISO market and other markets, as well as a transmission developer.

Terry commented on the Midwest ISO processes and issues with the TOA where LS Power could be more helpful with the process but isn't able to participate. FERC is wrestling with the issues and, probably each RTO to some degree.

e. Munis/Coop/TDU (Chris Plante)
Chris discussed study of contractual and economic dispatch in MTEP with Director Evans. The sector sees a tendency to drop contractual in favor of just economic and encouraged maintaining both until such a time that we have a centralized capacity market.

The sector would support notion of an objective planning function in which Midwest ISO would minimize the cost of energy to people in the market, which is affected by economic dispatch leading to upgrades.

Chris commented that probably many people feel frustration that as a whole we've done a lot of band-aid fixes and now need to do "the big stuff". That takes time to study and get through the process, license and construct; the entire process takes a long time.

f. Transmission Owners (JoAnn Thompson)
JoAnn pointed out comments in the sector paper that they believe the opportunity exists for all stakeholders to get data from Midwest ISO and submit proposals or suggestions as part of the transparent planning process. They encourage Midwest ISO to continue engaging in an open and transparent dialogue with stakeholders in developing plans and providing data to regulators. The sector does not need Midwest ISO to take on the role of integrated resource planner, but it would be helpful to hear suggestions, for example, of a more efficient location for a generator to build if one were identified.

g. Eligible End Users (Kevin Murray)
No additional comments provided; no participant questions.

h. Coordinating Members (no comments provided)

6. Planning Advisory Committee MTEP Update* (Julie Voeck)
A meeting was held in early October to finalize review and prepare comments on MTEP09. The PAC approved a motion to forward the MTEP09 report to the Advisory Committee and Board of Directors for approval. Comments were provided to Midwest ISO at several points, and this year there were

significantly fewer than historically. This was primarily due to improved processes and Subregional Planning Meetings.

A couple of areas of concern: data assumptions (consistent, transparent, SH ability to provide input); various scenarios MISO used looking at planning into the future; planning issue and coordination improvements needed (more frequent coordination might be necessary and helpful); PAC will look at taking input given to staff, responses, and putting together an action plan and modifications to how PAC will work going forward. Bob McKee will be the chair of the PAC starting in November 2009.

The Advisory Committee opted not to take a vote on MTEP09 and relied on the expertise of the PAC members.

7. GFA Filing Update (Richard Doying)
Richard discussed the background of the scheduling and settlement provisions set for "Carved-Out GFAs" and the issue of further contributing to the acknowledged cost shift from GFA load to OATT service load under the tariff. Midwest ISO proposed to limit Carve-Out GFA treatment as an option available to new members and otherwise receive the benefits that the market provides. These changes would modify Section 38.8.3(A) of the tariff after November 1, 2009. No changes are proposed to the treatment of existing Carve-Out GFAs. A filing with FERC to approve these changes will be made on Friday, October 16.

8. RSG Task Force Update* (Jason Minalga)
Jason's full update was provided with meeting materials. The RSGTF has been on aggressive and stressful timeline given the current filing date of November 5. A request for a 30 day extension to file is currently before FERC, which would move the submittal date to December 5. The timeline in the presentation is given on the basis of not being granted the extension as the response has not been received yet.

Jason recognized Ginger Jenkins and Stakeholder Relations for their work, as well as Mark Volpe for taking time to step up and provide input.

Jason agreed with the suggestion that if an extension is granted, a 3-day RSGTF meeting would be in order, possibly with an invitation extended to Dr. Patton. Additional information will be posted on the Midwest ISO web calendar and sent to stakeholder exploder lists.

9. Customer Service Survey (Sidney Jackson)
This update was also given in the Information Forum on October 13. One of the major goals is to mirror some of the success had in 20089. an invitation will be mailed out in mid-November with 30 days to complete.

10. Midwest ISO Website Redesign Update (Deb Lang)
Deb reviewed the process being used to update the Midwest ISO website, currently in the analysis phase. Stakeholder participation is being encouraged via interviews, surveys and providing information. The timeline for phase I is to be testing the prototype by the end of 2009, with additional work next year and final launch by September. Steve Kozey also discussed goals and process. A feedback survey will be blasted to the broad stakeholder committee yet this week.

11. Advisory Committee Items (Gary Mathis)
a. Self Assessment Discussion

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The suggestion was raised to review the management plan on a quarterly basis; after discussion Gary reminded those on the Advisory Committee of the existing process asking for a commitment from interested parties to be more involved. This issue will be revisited in a future meeting.

In January, the Advisory Committee will begin reassessment of the charter and determining if a different type of role is needed. Commissioner Lemmie pointed out that if the meeting agenda is so full it's not possible to have a policy discussion, the Advisory Committee could exist for administrative purposes (as it is functioning now). Another alternative would be to have a consent agenda where materials have been provided for review in advance and are not covered during the meeting.

Please submit comments to Gary, David or Alison.

b. Hot Topics for 2010
Sectors were asked to rank Hot Topics in consecutive order of importance. The method used was supported by Advisory Committee members. Gary will notify the Board of Directors in their October 15 meeting of the top 5 issues selected and request their feedback. The top 5 items are:
1) Coordination improvements between PJM (or other RTOs) and Midwest ISO
2) Long term perspective – new products and services and strategic direction
3) Tie: adequate price signals
3) Tie: MTEP and resource adequacy
5) Wind integration and cost allocation

c. AC Sector Reps for 2010*
A reminder email will be sent out for 2010 sector representatives to be sent to Alison.

d. Nominating Committee for 2010 AC Leadership*
Jim Keller, Robb Mork and Marka Shaw volunteered to participate in this committee. Alison will send a request via email for additional interested parties to let her know.

e. Alternate Dispute Resolution Committee (2 members)*
2 members of the ADR Committee (Wayne Harris, Sherry May) have terms expiring at the end of 2009, but have expressed an interest in serving again. Steve Kozey discussed the procedure, where in parties do not have to be members of the Advisory Committee to participate in the ADRC, but the Advisory Committee recommends to the Board of Directors who those individuals are. Gary will solicit additional volunteers for a vote in December.

f. Review AC Management Plan
No comments.

g. November 18 AC Meeting Discussion*
The Board of Directors does not meet in November and there are currently no agenda items set. The following meeting will be December 2.

OMS recommended not meeting in November because of conflicting meetings.
The TOs recommended not meeting in November.

A few members recommended having a conference call at minimum to receive an RSGTF update, or being provided with a written update from Jason Minalga. It was also recommended to have a Q & A session with Dr. Patton if his quarterly report is available.

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12. Standing Committee/Other Stakeholder Committee Reports

a. Finance Subcommittee 2010 Budget Update* (Joe Buckley)

The capital budget, including the new data center, is approximately $40 million. The operating budget is holding stead at approximately $100 million. Joe offered to provide any additional reports desired by the AC, or needed by the FSC.

September 15: FSC review of preliminary 2010 budget (complete)
October 15: stakeholder and sector input on capital projects > $500,000 due
October 19: FSC meeting (responses to information requested at first meeting; stakeholder input on capital projects > $500,000)
November 19: FSC meeting (review final budget submission by management to Audit & Finance Committee of Board of Directors)
December 2: FSC report to Advisory Committee on 2010 budget

b. AC Nominating Committee of the BOD Update* (Bill Smith)

This committee consists of 5 people: 3 directors and 2 stakeholders nominated by the Advisory committee. 2 vacancies are coming open this year on the Board of Directors (Mike Curran and Gene Zeltmann) in the categories of transmission planning and executive/professional experience. Bill discussed the selection process that narrowed down 4 candidates, in addition to the re-running of our existing officers, which have been submitted to the Board for their consideration and action this week.

c. RECB Task Force* (Paul Jett for Lauren Azar)

Last meeting: September 30
Next meeting: October 28, November 10
The September meeting was attended by 106+ individuals; the task force heard updates on UMTDI and OMS CARP efforts, and Marya white provided responses to the decision tree on behalf of CARP. The group also considered the decision tree and continued discussion of injection / withdrawal. This will comprise the bulk of the agenda for the next meeting as well.

d. Steering Committee (David Hastings)

The committee update report is posted with materials. In tomorrows meeting, discussion will focus around delegation of wind integration and related issues to the various Midwest ISO committees.

e. MSC Update (FTRWG Motions) (Barry Trayers)

3 motions passed in the MSC, 2 on FTRs trying to make process more efficient and allow for FTRs that no longer have transactions attached to be discontinued. (They received no opposition in the FTRWG or MSC.) The other motion was on improving earlier availability of non firm transactions. These move next to the TO committee for review.

f. Transmission Owners'* (JoAnn Thompson for Kevin Largura)

Cost allocation remains a top priority for TOs, who continue to participate in the RECBTF and watch the CARP process. Regional planning is a key focus and they're actively participating in a variety of initiatives around planning of the transmission system.

g. Organization of Midwest ISO States (Bill Smith)

Items provided in the report are regular and continuous ongoing work and filings. The OMS annual meeting was held October 13, at which time officers for 2010 were elected as follows:
President: Valerie Lemmie
Vice President (AC member): Monica Martinez

√ Denotes Potential Voting Item * Denotes Report is Oral

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Secretary (AC member): David Armstrong
Treasurer: Jeff David
At-Large Member of Executive Committee (AC member): Rob Burtson

OMS also had a brainstorming session on goals that will be refined, ranked and voted on for adoption in 2010. Some of those items match discussion in today's meeting.

13. New Business* (Gary Mathis)

No comment.

14. Recap – Issues/Assignments* (Alison Johnson)

1. If FERC allows the requested 30 day extension, a meeting will be scheduled to allow stakeholders to review the RSGTF findings and recommendations prior to Midwest ISO filing.
2. The list of Hot Topic recommendations will be forwarded to Board of Directors.
3. Sectors will send their Advisory Committee representatives for 2010 with contact information to Alison Johnson and Gary Mathis.
4. Alison Johnson will send a notice to AC membership to solicit volunteers to the Nominating Committee of the 2010 AC membership
5. An email will be sent to solicit nominations for the ADR Committee including a list of those currently serving. Elections will be held at the December AC meeting.
6. A conference call will be scheduled on November 18 in place of an in person Advisory Committee meeting.

Meeting adjourned at 2:48 pm ET.

Rotating Agenda Team November:	Ann Scott Steve Gaarde Allan Silk
Upcoming Hot Topics: December	Resource Adequacy

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Planning Advisory Committee
Conference Call Only
November 4, 2009
1:00 to 4:00 pm EPT
Dial-in and WebEx information available at www.midwestmarket.org

Minutes

1. Administrative Items (Bob McKee)

a. Welcome and Roll Call

Meeting called to order at 1:00 pm EPT.

Attendees:
Chair: Bob McKee, ATC
Midwest ISO Liaison: Jennifer Curran
Stakeholder Relations: Amanda Brower

TDU Sector: Rich Cottrell, Consumers
IPP Sector: Julie Voeck, NextEra Energy
TO Sector: Matt Holtz, NIPSCO
Regulatory Sector: Valerie Lemmie, PSC OH

Jeff Webb, Midwest ISO
Paul Schumacher, We Energies
Neil Balu, WPSC
Joann Thompson, Otter Tail
Ron Ryckman, Ameren
Laura Rauch, Midwest ISO
Bill Malcolm, Midwest ISO
Mike Amiss, CES
Jeremy Fisher, Otter Tail
John Thomason, MGE
Jim Swanson, MidAmerican
Gary Fuerst, FirstEnergy
Dave Johnston, IURC
Jon Riley, AEP
Tom Vitez, ITC
Karie Barczak, DTE
Jessica Van Heusan, MI PSC
Mark Wehlage, Xcel
Flora Flygt, ATC
Cathy Cole, PSC MI
Clayton Larson, PSC WI
Clint Burrow, GRE
Daniel Kline, Xcel
David Johnston, IURC
David Nick, DTE
Diwakar Tewari, Midwest ISO
Ed Kirschner, Duke Energy
Eugene Warnecke, Ameren
Gary Fuerst, FirstEnergy
Andrew Jensen

b. Review / Approve Agenda

Bob requested that Midwest ISO give a brief update on the RECB Task Force and Phase I filing.

c. Approval of October 7 Meeting Minutes √

Redline item noted received today and posted with meeting materials. Minutes were approved by voice vote.

2. Review of stakeholder feedback on Coffeen Write-up (Jeff Webb)

Last meeting: PAC received an update on this project and significance that it is the first RECB II eligible project for cost sharing. Some stakeholder comments were provided and incorporated; a redline write up was provided with meeting materials. This was also discussed with the System Planning Committee of the Board of Directors and they were receptive to the project. Nothing additional is planned to go to the Board except for the final write up with edits incorporated.

√ Denotes Potential Voting Item * Denotes Report is Oral

Joann Thompson noted one area indicating that numerous discussions were held with "Transmission Owners" and collectively they're not aware of these meetings. It should actually read "transmission owners". Jeff will make the edit.

3. PAC Action Plans from MTEP Feedback (McKee/Curran)

Stakeholder feedback was provided to Midwest ISO on the MTEP write up, and at the last meeting a summary of comments was discussed with feedback due in this meeting regarding the PAC action plan. This was posted with meeting materials.

Jennifer noted that most of the items listed made it to the "action plan" list because they were items staff perceived needed to be worked through the PAC or other stakeholder forum. She reviewed each item indicating areas where staff could come back with a recommendation, or sent to another committee.

The first item on the list related to Security Constrained Economic Dispatch was referred to the Planning Subcommittee to develop a recommendation and bring back to the PAC. Missing on the list was a comment about PROMOD benchmarking, which staff also believes should be looked into further. This item was also assigned to the Planning Subcommittee.

Second item on procedure for stakeholders to provide project alternatives in the planning cycle; this will be a follow up item on the December agenda. Stakeholders should be prepared to discuss their ideas for addressing this, as well as other items for the 2010 PAC Workplan.

Third and fourth items were related, focusing on scenarios and sensitivities used in studies such as the Top Congested Flowgate Study: this will be an agenda item in a future meeting to have a robust discussion on details (assumptions and scenarios used, including in CARP work). Bob requested that materials be provided as far in advance as possible.

The PAC requested to receive quarterly updates from Midwest ISO on the Generator Interconnection Queue ("queue") and Transmission Service Requests (TSRs).

4. Assignment of Wind Integration Items (McKee)

A series of wind integration workshops were held through 2009. Midwest ISO has also been working internally on a number of issues. The PAC, Reliability Subcommittee and Market Subcommittee were assigned several issues to address in Steering Committee meeting on October 15. Items assigned to the PAC are:

- (Motion 8) The Midwest ISO recommends assignment of the wind integration work related to interconnection of Energy Resources to the Planning Advisory Committee
- (Motion 9) The Midwest ISO recommends assignment of the wind integration work related to System Stability and Conditions to the Planning Advisory Committee
- (Motion 10)The Midwest ISO recommends assignment of the wind integration work related to developing Interconnection requirements to exploit new technologies to the Planning Advisory Committee

Stakeholder recommendations were that items assigned to lower committees should be worked back up through the PAC for coordination, and that Midwest ISO should provide presentations explaining each item simultaneous to the work being done in each lower committee.

Further explanation of Motion 8 will be provided by Midwest ISO at the December meeting. This item was assigned to the IPTF, and work will begin after the Market Subcommittee is finished with the preliminary work. (The PAC will coordinate with the chair of the MSC and IPTF.)

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Motion 9 work is already partially underway in the Planning Subcommittee. This work is within the scope of the PSC. An update from staff and the PSC was requested for the December PAC meeting.

Motion 10 work on new technologies was assigned to the IPTF; a background presentation will be provided to the PAC in December.

Jennifer noted that all of these items are being coordinated internally as well; a point person for each area (Markets, Reliability and Planning) has been identified to ensure that proper coordination is being done. The plan for the final work piece is for recommendations to go to Midwest ISO for business process and/or tariff changes. The Steering Committee discussed two approaches for collecting the roll up of issues in their last meeting: an additional workshop, or coordination through MSC (as the owner of the most issues). They will discuss further in their next meeting on November 19. Bob would also like to have quarterly updates on where all the issues are and what the expectations are for the filing (tentative for the end of the second quarter 2010).

5. **RGOS Update (Miland/Smith)**
Jarred Miland provided an update on RGOS I as posted with meeting materials. Most discussion was focused on slide 9 showing. Jarred was asked to post the model used to the FTP site. TRG meetings are not scheduled at this time, but work is in progress. Those dates will be sent to stakeholders when available.

RGOS I draft executive report should be available by end of next week to DST.
RGOS II TRG will likely meet towards the end of December.

6. **Interconnection Queue SPA (System Planning & Analysis) Update (Tewari)**
Diwakar provided a high level update; additional details are provided with meeting materials and on the Generator Interconnection page of the Midwest ISO website at:
http://midwestmarket.org/page/Generator+Interconnection

Match 29 is the last deadline for projects in the queue to meet their true-up requirements; after that if they aren't in compliance they will be moved to the bottom of the queue.

7. **2010 PAC Meeting Schedule (McKee/Curran)**
Bob discussed the intent of adjusting the schedule of Planning group meetings. The proposed dates provided with meeting materials were supported by the PAC and will be posted on the web calendar by the end of the year. (See list below)

8. **New Business (All)**
Jennifer discussed the RECB Phase I Order from October 23, conditionally accepting the proposed revisions to GI project cost sharing. Generators are now responsible for 90% of the cost of a 345 kV+ project and 100% of network upgrades below 345 kV, with the exception that the ATC and ITC zones have maintained their prior 100% reimbursement approach. One immediate compliance item is for ITC language to add back the language requiring a demonstration of network resource or PPA. FERC has required the superseding methodology (Phase II) to be filed by July 15, 2010. The RECBTF is hard at work and will be harder at work in 2010 and will likely go to twice per month meetings to meet that deadline.

No other new business was identified.

Meeting adjourned at 3:30 pm EPT.

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Next Meeting: December 9, 2009

2010 Meeting Dates:

January 27	April 21	July 21	October 27
February 24	May 26	August 25	November 23
March 24	June 23	September 22	December 15

√ Indicates potential voting item

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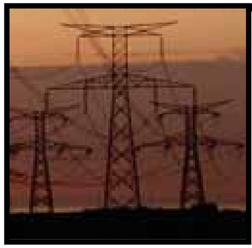
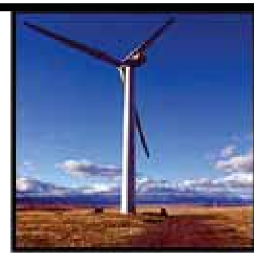


Transmission Development Challenges and Proposed Solutions

From the Perspective of an
Independent Transmission Developer
and a
Transmission Dependent Utility

November 12th, 2009

Regional Transmission Planning

- Regional transmission system planning in an open, timely, inclusive and transparent fashion does not yet exist.

  - While Regional Transmission Organizations (RTOs) have in many cases assumed a coordination/administrative role in regional planning, the transmission owners and their competitive agendas still drive the process and decision criteria.

  - Third-party stakeholders are currently discouraged from proposing new transmission projects because the project will ultimately be constructed by the incumbent utility anyway.

  - ✓ [redacted] **Under such a scenario, why would any third-party stakeholder [redacted]e in a process where they don't have an opportunity to achieve cost [redacted]**

  - ✓ **It is important that RTOs remain impartial in the transmission process specifically incorporating and taking into consideration the all stakeholders (not just transmission owners).**

New Transmission Investment

- Investment in the development of new transmission facilities beyond reliability projects is currently a closed process and needs to be opened up.

  - Two potential avenues to open up the development of new economic and renewable transmission projects include:
    1) Project sponsor gets Right of First Refusal ("RFOR") – Regional transmission planning could include a process where transmission projects are submitted into the annual regional and/or interregional transmission planning process. If the projects are approved in the transmission plan the project sponsor get the Right of First Refusal to develop and construct the project; and
    2) A new competitive process (CREZ-like) – Regional transmission planning could include a clear competitive process in assigning the construction of new transmission facilities that have been approved in either regional or interregional plans.

  - ✓ [redacted] **Why should new transmission development and construction be left to only [redacted] ion owners when many transmission owners are vertically integrated utilities [redacted] luctant to invest in new transmission facilities for the risk of having to file a rate [redacted] cover the investment?**

  - ✓ [redacted] **To facilitate the construction of new transmission in times of economic [redacted] ty, it is important that new sources of capital are evaluated and tapped such as [redacted] ent transmission developers and transmission dependent utilities (i.e., [redacted] s, cooperatives and non-transmission owning utilities).**

Cost Allocation and Cost Recovery for New Transmission

- Cost allocation and cost recovery principles for new transmission development are still unclear and must be firmly established to reduce transmission development and investment risk.

  - **It is important that FERC take responsibility, through a rulemaking or other mechanism, for establishing clear cost allocation and cost recovery principles that ensure a fair recovery for new transmission investment that is approved in regional and interregional plans.**

  - **Additionally, FERC's principles for clear cost allocation and cost recovery should be mindful of new generation interconnections and the diversity of the benefits that will be provided over the life of the new transmission**

Questions?

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OMS answers to Resource Adequcy Hot Topic questions for December 2009 AC meeting
Combined reponse set by DGN – Draft - November 12, 2009

Questions:

1. Overall, are there any major reasons to believe that the resource adequacy construct is not likely to achieve resource adequacy reliably and efficiently?
a) In the next five years?
b). More than five years?

No. The present resource adequacy construct embracing LOLE standards and the planning reserve method and the recent Module E approval as being implemented by MISO shows that states have plenty of capacity and reserves for the next five and ten years. System adequacy is fine. The combination of the bilateral market, the voluntary capacity market, states with more aggressive construction program, and the recent demand destruction due to the mini-depression has put the MISO footprint on a sound basis. There are major reasons to believe, however, that the workings of the resource adequacy construct, in conjunction with energy and ancillary services markets, **are** likely to achieve resource adequacy reliability and efficiently because the markets are designed to pay resources for being the right type in the right place and the right time – especially given the ongoing changes to further improve the markets.

Illinois Minority Opinion: MISO Module E does nothing to ensure reliability. Reliability is currently being ensured by other means. MISO Module E just creates administrative burdens, imposes inefficiencies and raises costs that consumers must pay. Reliability in the long run can be ensured by fine-tuning MISO's energy and operating reserves markets and by enabling price responsive demand for retail customers.

2. Module E was crafted explicitly to respect states' rights regarding resource adequacy, while ensuring reliable grid operation. Has the implementation of Module E supported this objective?

Yes. States have been able to pursue individualized resource adequacy approaches. One example is state RPS requirements. Another is state oversight of a utility's operation of their facilities and the cost recovery of closing or mothballing generating plants. While respecting states' rights to implement price responsive demand programs, such programs can create friction in policy between retail and .non-retail choice states. One such state, for example, is leery of the programs operating as conceived, absent a targeted, non-firm and firm (in a worse case situation) load shedding program which the IMM has opposed in a written opinion.

Illinois Minority Opinion: No. MISO would better support states' rights by abandoning the Module E approach and allowing state commission and state legislative designs to continue to provide for resource adequacy either through traditional regulatory methods or through market means combined with retail customer empowerment.

3. Has the resource adequacy construct helped to promote (or not hindered) efficient, liquid bilateral markets for capacity in long-term contracts and planning resource credits? For example, by increasing transparency in price and demand? Is the monthly construct optimal?

The construct has not hindered bilateral markets. States still review the purchase of power by LSEs under their jurisdiction, and can base their review on whether the resulting power will be reasonably priced compared to alternatives, just as they have done in the past. While the information for other bilateral contracts is lacking, other price information has grown. The monthly construct is not optimal, but is a good workable compromise between an annual construct that meets the intent of an annual planning reserve requirement and a weekly construct that reflects frequent LSE load switching that occurs in retail choice states. See answer to Question 9 about transparency.

Illinois Minority Opinion: MISO Module E has created an unnecessary administrative bureaucracy. It mandates a particular type and level of hedging regardless of the retail market designs chosen by state legislators and state regulators.

4. Are all resource types treated comparably/equitably (i.e., generation, small generation, DR, imported resources, non-dispatchable resources such as wind, BTMG, use-limited resources, etc.) with respect to qualification requirements, performance requirements, penalties, etc.?

Yes in the sense that all can or soon will be able to participate in the market and planning functions. No in the sense that qualification levels are different to properly reflect the different operating characteristics of each type of resource; such as dispatchability, rate of change, outage rates, etc. As for demand and price responsive demand programs, the jury is still out, as such programs are being brought into the market, some are evolving, some are new, and MISO is still working through the details in the stakeholder process. This process should be allowed to reach its fruition. As for wind resources, MISO has rolled out a statistical approach that looks promising. In one of OMS' earlier comments to the Board, OMS suggested the use of statistical methods, and MISO's adoption and exploration of this technique is appropriate and should be commended. The continued refinement of wind analysis is appreciated.

Illinois Minority Opinion: Ensuring resource comparability in a capacity construct is a quagmire that will produce unending arguments. The better approach is to facilitate big-tent participation in the energy and operating reserves market.

5. Does the Resource Adequacy construct adequately address the special circumstances in retail choice states? If not, what steps should Midwest ISO pursue to remedy this?

Mostly it does. The use of a monthly construct (instead of an annual construct) to recognize load switching in retail choice states is one example.

Illinois Minority Opinion: No. The MISO Module E approach directly conflicts with state policy that would seek to ensure resource adequacy through retail customer choice and retail customer price responsive demand built on a foundation of an efficient regional energy and operating reserves wholesale spot market.

6. In a previous Advisory Committee Hot Topic, the sectors weighed in on Load Forecasting. After six (6) months of the new Resource Adequacy construct, has your sector view changed at all? How?

We have only had one peak season since RA construct and that was in a recession and during one of the coolest August in the upper Midwest history. The monthly LSE Under Forecast Assessment shows the number of CP nodes under forecasted and the number of Market Participants with those nodes. It has been suggested by others that additional information on the MWs and distribution of the MWs would be helpful. OMS is collecting further comments.

Illinois Minority Opinion: If Module E is eliminated, this particular forecasting controversy would evaporate.

7. How does your sector view the efficiency and effectiveness of the Voluntary Capacity Auction in supporting Resource Adequacy?

The VCA is a useful adjunct. Prices have been quite low reflecting the surplus of capacity in MISO at the present time. Therefore, its effectiveness at accommodating short term solutions for different entities is difficult to judge. The VCA represents a small portion of capacity market buyers that are exposed so it is also not clear how and if it relates to prices of bilateral contracts in general. In some situations, for example, the deficiency charge could have more effect on capacity market prices than the VCA.

Illinois Minority Opinion: There is no meaningful market power monitoring and no market power mitigation in the VCA. State regulators and independent analysts do not have access to the data needed to conduct independent analyses. Consequently, there is no way to respond in an informed way to a question about VCA efficiency and effectiveness.

8. Scarcity pricing is one of the drivers in the Midwest ISO Resource Adequacy design intended to maintain long term reliability. Are the rules related to scarcity pricing in regards to this objective?

a) Are the current scarcity price values/formulas adequate in meeting this objective?

They are adequate in terms of objective, but still need the further improvements that the Midwest ISO is working on, such as software fixes to prevent false scarcity events and improvements in pricing.

Illinois Minority Opinion: The arbitrary capacity mandates of MISO's Module E undercut the purpose of scarcity pricing in the energy and operating reserves markets. The energy and operating reserve scarcity pricing approach has never really been allowed to work because Module E was implemented.

b) Are any changes needed to the emergency operating procedures currently in place by which Midwest ISO implements scarcity pricing (EOP - 002)?

The current ASM products have been adequate until recently. However, as the non-dipatchable wind penetration continues to increases, the technical task teams that are studying the current operations and future systems are likely to suggesting some new product that has a 4 hour or so time frame. That product would possibly have a stand-by payment and then a forward pricing mechanism with some rate of response (MW up and/or MW down) capability. This will need additional research. The anticipated Eastern Wind Integration Transmission Study should provide additional insight.

Illinois Minority Opinion: Yes. MISO's current emergency operating procedures undercut the market price signals that would efficiently ensure reliability and make the need for deployment of the emergency operating procedures more likely.

c) Do the current Tariff and operating provisions facilitate transparency of the scarcity pricing process?

Yes. Such transparency should not include false scarcity events, however. The OMS appreciates the Midwest ISO's efforts to identify and correct procedures to prevent scarcity pricing when there are adequate resources.

Illinois Minority Opinion: It's not clear what this question is getting at.

d) Has/Does the combination of capacity requirements plus energy/scarcity pricing provide adequate incentives to ensure long-term resource adequacy?

The question addresses the central resource adequacy issue, which is whether relatively short-term prices can provide the proper incentives to ensure long-term resource adequacy. The OMS says yes. Some have said that the longer term prices are needed, such as 3 or 4 year forward prices used by RTOs to the east in their resource adequacy constructs. In the context of long-term resource adequacy, however, they are also short-term prices. The Midwest ISO capacity requirements and energy/scarcity pricing, when considered in the bigger picture of state resource adequacy and financial market risk exposure, are the right combination. RTOs cannot be expected to provide resource providers with long term financial security in energy and capacity markets that are volatile over time.

Illinois Minority Opinion: A well-designed energy and operating reserves market that features scarcity pricing combined with state policy maker decisions regarding hedging levels and retail customer empowerment would efficiently ensure resource adequacy. There is no need for a separate capacity construct.

9. If you could change one thing to improve the Resource Adequacy mechanism, what would it be?

The one change would be more transparent bilateral contract terms and prices. Perhaps, the FERC should be requested to have MISO post results of bilateral arrangements after a certain period of time. This would require entities reporting to MISO price and quantity information of their bilateral arrangements, and MISO posting it with an appropriate lag of say 6 months. Party and counter party information could remain confidential, but pricing, quantity, and duration would be made public.

Illinois Minority Opinion: Eliminate Module E. Fine-tune the energy and ancillary services market so that it sends more accurate price signals. Correct the current hamstrung scarcity pricing mechanism. Enable retail customer price responsive demand.

Organization of MISO States
Process for Approving Position Statements for FERC and MISO

Goals: Approved 10/14/04

1) Help states form positions on issues
   a. Perform thorough analysis of issues
   b. Test differences and sharpen analysis through discussion of differences in order to gain better understanding of the issues
2) Express collective position of states to decision maker
   a. Build consensus when possible
   b. Allow parallel presentation of contrasting viewpoints

Stage 1 – Working Group Preparation of an Issues Document Approved 10/14/04

Section 1- Assignment of topics to a Working group, or Working groups:
The OMS Executive Committee assigns all new topics to either an existing working group or to a new working group when needed. When a topic in an active docket has already been assigned to a working group, the Executive Director (ED) is authorized to make follow-up assignments. As time is of the essence in such cases, the ED shall timely make such assignments and shall immediately inform the Executive Committee. The ED may delegate this responsibility as necessary.

Section 2 - Review of OMS Work Plan by Executive Committee:
The ED shall include in his/her monthly report, or as necessary, ~~-~~a list of FERC and MISO (or other) actions expected in the coming 60 days that may require Working Group assignment. The Executive Committee shall review the list of action items provided by the ED each month and shall direct the ED to give early warning of possible assignments to OMS working groups. The ED shall inform the Executive Committee, via electronic mail, of the completion of such notifications.

Section 3 - Approving the Timetable for Issues Documents:
Providing the greatest possible lead time, the ED, in consultation with the president, will prepare a schedule which outlines a time line of when document issues must come to the OMS Board's attention. The schedule shall include the date that the Board decides issues that will be included in the document, the date that first (and second drafts when possible) will be shared with the membership, and the date that the board will be taking final action on the document.

The Board of Directors will approve the time line of when document issues must come to the OMS Board's attention. Board members are encouraged to note key dates and work to facilitate appropriate action by their Commission so that Board members can vote on the document.

The Board schedule will include a board meeting when Commissioners determine what issues will be included in the document, and give general policy direction to the working groups. Working groups are encouraged to develop "principles" or a short outline that the Board can consider as it advises on policy direction. *Exceptions: Sometimes proceedings that OMS wishes to comment on may have a very short timeline. In these situations, the board may not have time to take ~~these~~ all the above steps. In those situations, the board will determine how it wishes to proceed.*

Section 4 - Preparation of the Issues Document:
Working groups, which are involved in the document, will encourage members to volunteer to write sections of the issues document. Assignments should be reported to the ED of OMS.

Working groups shall promptly set up their own internal schedule to review all sections of an issues document. The working group's internal schedule must coordinate with the Board's approved time line of when document issues must come to the OMS Board's attention. (see above) The ED shall track Working Group progress and, in the event he/she becomes concerned that progress is inadequate, shall first consult with the working group chair. If such consultation fails to resolve the problem, the Executive Committee shall be informed immediately.

Working groups shall strive for consensus. When working groups know there are strong differences that should be expressed on a specific issue in the document, comments reflecting two or more positions may be developed by the working groups.

All members of a working group shall have the opportunity to read a "draft" section of an issues document, and offer suggestions and changes at least once prior to submittal to the Executive Director for inclusion in an OMS document. If more than one work group is assigned to work on an issue, each working group must have an opportunity to read a "draft" section and offer suggestions and changes at least once prior to submittal to the Executive Director for inclusion in the OMS document.
When two or more working groups have provided sections of the draft documents, the ED shall assure the internal consistency of the completed document, whether draft or final.

The chair or chairs of the working groups involved shall submit the document to the ED in a timely manner.

The ED will only include information in issues documents that follows the procedure outlined in this section "Preparation of the Issues Document." *Exceptions: There may be situations when short timelines, or other factors, do not allow all steps of this process to take place. The ED should then note, in an attachment to the draft document, which steps have not taken place in preparation of the document*.

Stage 2– Board Discussion of the Document, Including Proposed Changes

Approved 12/9/04

Section 1
The Executive Director will submit to the Board, in a timely manner, the final version of a working group issues document.   If all of the steps of the process outlined in Stage 1 have not been able to be followed, the ED should then note, in an attachment to the issues document, which steps have not taken place in preparation of the document.

Section 2
Board members or associate members may suggest language changes to the document at the Board meeting, and are encouraged to circulate them to membership, before the meeting, to facilitate good understanding of the language changes proposed. Since the Executive Director has the most up to date e-mail list, Board members are encouraged to send proposed changes to the ED for circulation, and are also encouraged to "track" all changes to a final working group issues document.

Section 3

The Board will decide how it wishes to discuss proposed changes to the document. For example, does it wish to proceed page by page or section by section through the document and have the presiding officer ask if there are any questions or suggested changes and discuss and vote upon suggested changes individually? Or does the Board wish to start with a “new” revised version of the document, which includes several changes?

Stage 3 - Voting Process

Approved 8/12/04

Section 1

All members are encouraged to vote on the final document rather than to abstain. If procedural reasons preclude a member from voting, members are encouraged to state this at the beginning of the discussion of the document.

Section 2

Members who have to abstain in the vote on the final document are encouraged to share their thoughts in the discussion of the issues, so that OMS members have as complete an understanding of the issues as possible prior to voting.

Section 3 - Voting on different points of view within a document

If discussion and study of issues documents brings forward more than one point of view on a specific issue *within the document*, board members may be asked to indicate which position they favor. The first priority will be to work to develop consensus language on these specific issues *within the document*. If consensus language can~~-~~not be adopted, ~~–~~varying positions would be fully explained including the basis for any differences. The document will indicate which states favor specific positions. The goal of the document is to reflect differences in a positive manner in order to provide as much information as possible to the recipient of the final document.

Section 4

Only members present at the meeting, by proxy or in person, may vote on an issue document. States not present at the meeting may choose to sign on to the final document within a reasonable period of time, but may not propose any changes to the document.

Section 5

Some members may need time after the board meeting for procedural reasons to confirm their votes. The Board of Directors may grant members present an extended period not to exceed ten days, depending on the filing schedule, ~~may grant members up to 24 hours~~ to confirm their votes with the Secretary and the Executive Director~~, depending on the filing schedule~~.
Members who are granted an extended voting period ~~up to 24 hours,~~ may confirm or change their votes within that timeframe but may not propose any changes to the document. The final vote will not be determined until the members who have been granted an extension ~~up to 24 hours~~ have confirmed their votes.

Stage ~~3~~4 - Filing of Comments

If the final vote reflects that a majority of members wish to file the comments, the comments will be filed.

DRAFT November 09 DRAFT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Processes Under Order No. 890	))	Docket No. AD09-8-000

COMMENTS OF THE ORGANIZATION OF MISO STATES

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Request for Comments issued on October 8, 2009, the Organization of MISO States ("OMS") hereby submits the following comments regarding transmission planning processes and transmission cost allocation. The Commission originally requested that Comments be submitted no later than November 9, 2009, but subsequently extended that deadline to November 23, 2009.

I. DISCUSSION

The Commission seeks comments about how the current transmission planning processes and transmission cost allocation practices can be improved. The OMS supports the Commission's initiative to examine the effectiveness of existing transmission planning processes and cost allocation practices, particularly focusing on their regional and inter-regional aspects. The OMS cautions, however, that in its efforts to facilitate transmission investment, the Commission should not abandon principles that have served the industry well for decades. Given the high stakes for the nation in effective energy policy, the Commission must ensure that the processes being developed for regional and inter-regional transmission planning and the practices for transmission cost allocation provide for the nation's future energy needs, while recognizing individual states' interests in ensuring the reliable service to retail customers at reasonable rates. Given the geographic expanse, abundant resource endowment, unique electrical topology and illogical seams and borders of the Midwest ISO region, the OMS has a particular interest and great stake in the Commission's examination of transmission planning and transmission cost allocation policies.

In particular, the OMS recommends that the Commission recognize and support the ongoing initiatives of state regulators, state policymakers, RTOs and stakeholders in particular parts of the country to address and resolve transmission planning, development and cost allocation in ways acceptable to the various needs and multiple interests in those parts of the country. The need for improved transmission planning and fair cost allocation will only increase if policies require the development and construction of additional renewable energy and no-carbon or low-carbon generation. New transmission will be necessary to support these policy choices, which may require that new renewable power be transmitted -across long distances and multiple regions. In addition to improved transmission planning, fair transmission cost allocation in which cost causers and beneficiaries pay will become even more important. If the ongoing regional and inter-regional grass-roots efforts to develop policy solutions are able to produce broad consensus, or at least a common understanding regarding solutions, such solutions would create a strong foundation of industry certainty that would likely have more permanence than federally imposed solutions.

The OMS urges the Commission to act only in geographic areas and on issue areas where state and stakeholder action is absent or not working and Commission action may be necessary to stimulate progress. The Commission should allow the genuine state and regional-level efforts that have already been initiated to produce progress to proceed in those efforts. If, after a reasonable period of time without substantive results being produced by the existing cooperative efforts led by state policymakers, the Commission should consider issuing policy directives to address transmission planning and transmission cost allocation policies.

A. Transmission Planning Process

Historically, transmission planning and development focused on local reliability needs. However, the development of wholesale energy markets, the central dispatch of generation and the establishment of renewable energy portfolios have shifted this paradigm significantly. This requires transmission planners to perform reliability and economic analyses over much larger footprints. There is also the potential for Congress to enact climate change legislation that will also affect transmission planning and transmission system needs in significant ways. If climate legislation is enacted that restricts the emission of carbon dioxide, it is likely to have a transformational impact on the generation portfolio in many states over a very short period of time. Such new energy policy could result in the construction of new transmission lines to deliver significantly more energy from locations that are remote from load centers. Before the Commission proceeds to implement a large scale planning proposal of its own choosing, the Commission should be aware that states and regional state committees in some areas of the country have already begun the process of adapting to this new era of transmission planning. Indeed, the American Recovery and Reinvestment Act of 2009 (“ARRA”) gives significant new impetus to creating a much larger and stronger collaborative approach among all stakeholders. These state and regional processes will lead to better transmission planning results than a federally-led process. These participants have an understanding of the local and regional concerns that are a key to the development of an effective transmission planning process.

At the state level, the OMS is aware of two significant efforts in the Midwest ISO footprint. First, the OMS has formed a Cost Allocation and Regional Planning (“CARP”) initiative. In January 2009, this group of thirteen states in the Midwest ISO began an initiative working with the Midwest ISO to consider new cost allocation methods. Part of this initiative includes the development of indicative regional transmission plans tied to particular sets of scenarios and to consider a cost-allocation methodology. Significant computer modeling of generation expansion and needed transmission infrastructure have been part of the CARP initiative. Results from this initiative may be ready as soon as early 2010.

The second state policy-maker led approach involves the governors and state commissions from five states. Specifically, governors from Iowa, North and South Dakota, Minnesota and Wisconsin have formed the Upper Midwest Transmission Development Initiative (“UMTDI”) with the goal of identifying necessary transmission infrastructure to deliver renewable energy from the western Midwest ISO footprint to states with renewable portfolio standard (“RPS”) requirements. The UMTDI participants are also investigating the potential that the five states could develop transmission lines that would provide for the export of renewable energy beyond the borders of the states engaged in this effort. The UMTDI effort is expected to finish its work in 2010 and is also examining cost allocation issues.

The CARP and UMTDI initiatives show that state leadership is already taking action to adjust to new transmission planning needs, the realities of the ARRA funding impacts and the possibility of new federal energy policy.

The most recent development in regional transmission planning is the largest in scope, comprising the entire Eastern Interconnection. The ARRA directed $80 million to the Department of Energy (“DOE”) to conduct resource assessments and provide technical assistance for interconnection-wide planning. The DOE released a Funding Opportunity Announcement (“FOA”) in June of 2009 that identified distinct roles for transmission planners and engineers (Topic A) as well as a specified role for state policymakers and regulators (Topic B).[1]

After the release of the FOA, representatives from Governors' offices, state energy offices, regulatory commissions and other leaders throughout the eastern United States proposed to the DOE on September 14, 2009 under Topic B that an Eastern Interconnection States' Planning Council ("EISPC") be established. One of EISPC's major goals is to have state policymakers within the Eastern Interconnection create and establish a coordinated and consistent set of directives and analyses (e.g., assumptions and scenarios) for the modeling that will take place with this funding by the DOE-selected Topic-A entity. Of the 41 jurisdictions in the Eastern Interconnection, 38 have filed letters of support for the proposal. This represents an impressive and unprecedented level of cooperation among the states in the Eastern Interconnection.

EISPC, CARP and the UMTDI are prime examples of the role that state leadership can play in transmission planning and the development of new transmission infrastructure. There are a variety of reasons why these state and regional processes are likely to produce better results than a federally-led process. First, state commissions have the ultimate responsibility for retail electric rates and are therefore keenly aware of how the costs of interstate transmission lines will flow to ratepayers. Second, transmission planning must accommodate state choices with respect to generation portfolios and the complementary demand-side programs. Third, state regulators are better situated to identify and address transmission upgrades such that they do not harm or require excessive upgrades to existing facilities. Lastly, with siting authority and a local presence, the states are in a much better position to obtain buy-in from those who will be affected

[1] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068

most by new transmission lines. State-level decision-making allows for more complete public information, participation, credibility and public acceptance.

The OMS encourages the Commission to support CARP, UMTDI, EISPC and other similar initiatives that may follow these models. The OMS also recommends that the Commission facilitate the development of additional such state-led transmission planning and cost allocation stakeholder efforts by framing and clarifying the range of available policy options, particularly with respect to inter-regional issues.

- **Are existing transmission planning processes adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers? Should prospective transmission developers coordinate their projects in the interest of "right-sizing" facilities to make the best possible use of available corridors and minimize environmental impacts? If so, what process should govern the identification and selection of projects that affect multiple systems?**

The Midwest ISO's intra-RTO transmission planning process is generally working well and the above-mentioned interconnection-wide transmission planning efforts are too new to judge. While some of the inter-regional issues may ultimately be addressed by larger planning efforts like EISPC, the inter-regional transmission planning processes need to be improved and merit Commission guidance. The OMS offers recommendations in this regard below.

In general, RTO planning efforts focus on identifying the needs of the customers within the RTO and issuing a transmission expansion plan that identifies and evaluates options and proposes a solution to meet those intra-RTO needs. While some RTOs, including the Midwest ISO, participate in inter-RTO planning, those activities are often separate from the RTO's internal planning efforts. Internal RTO planning efforts are generally aimed at developing a transmission expansion plan with projects that the RTO directs to be built. As such, inter-RTO planning efforts are largely an academic exercise, with no apparent coordination among the various regions.

Sound transmission planning should provide an orderly structure to coordinate transmission projects not only to "right size" facilities but to make the best use of transmission corridors and not unduly create more corridors or new constraints. To the extent transmission developers are able to work cooperatively together, project costs may be shared among them which should reduce each developer's project costs, thus benefitting the developers' customers.

Ideally, the purpose of any proposed project would be clearly stated and transparent. Potential developers would, on their own, collaborate on selecting and locating potential joint projects and introducing the joint project into their ISO/RTO planning process. However, when collaboration fails, then the ISO/RTO planning process should identify project or project-portion alternatives that could reduce overall costs, "right size" facilities to meet identified needs over a larger footprint or more efficiently use transmission corridors. The states where the projects would be located should, in certain cases, have this information to conduct their state regulatory processes and the separate developers would need to explain why such efficiencies should not be approved. However, in the case of large inter-regional projects, State Regulators may not be able to justify such large projects for their own states. In these cases regional cooperation will be critical to ensure that all transmission upgrades are "right sized" for current needs, as well as the foreseeable future. The identification and adoption of fair cost allocation or cost recovery methodologies will be an important piece of this necessary regional and inter-regional cooperation.

While the RTOs, particularly the Midwest ISO, have undertaken cross-border transmission planning, very little in the way of practical projects has, to date, come from it. As such, improvements should be made regarding coordination and goals of such endeavors.

- **Are there adequate opportunities for stakeholders to participate in planning activities that span different regions, including for example those undertaken pursuant to bilateral agreements?**

There is adequate opportunity for stakeholders to participate in planning activities. Indeed, there are numerous stakeholder forums at PJM and the Midwest ISO associated with transmission planning. However, the reality is that the practical ability of many stakeholders, including retail customers and those representing the interests of retail customers is limited. Transmission planning and energy industry practices generally are evolving rapidly. The Commission must understand that stakeholder resources, particularly those within state commissions and other customer and public interest representatives, are spread thin. To the extent that the Commission can identify policies that will streamline and focus state and regional efforts, the scarce resources of the state commissions and the stakeholders can be more effectively focused.

While there is some transmission planning coordination between the Midwest ISO and PJM, the effort is largely an add-on to existing intra-RTO practices rather than being a combined transmission planning process. What is missing from the current inter-regional planning continuum is a coordinated process that involves the stakeholders of all affected RTO regions and a focus on issues impacting the regional and inter-regional RTO footprints. Furthermore, inter-regional involvement by stakeholders is very challenging, in that stakeholders would have to be involved in multiple ISO/RTO processes simultaneously. In particular, state commissions that straddle the PJM/Midwest ISO seam struggle to meaningfully participate in the transmission planning efforts of both the Midwest ISO, PJM and SPP. Similarly, state commissions not close to RTO seams do not have the resources to participate in inter-seam planning, even though such actions would impact these states as well.

In sum, the inter-RTO transmission planning processes merit additional Commission guidance and the OMS makes recommendations below in this regard.

- **Is there adequate coordination among planning entities to provide consistency in the data, assumptions and models being used in planning activities?**

The OMS is not in a position to directly answer this question. The planning entities are in the best position to respond about consistency between the planning entities. However, it is clear that PJM and the Midwest ISO can be subject to some modeling inconsistencies such as those illustrated by the recent market flow calculation controversy in Docket No. ND10-01-000. Part of this settlement proceeding may include an investigation of whether the calculation errors impacted loop flow assumptions, day-ahead unit commitment and/or Financial Transmission Rights /Auction Revenue Rights auction results. While that matter involves market operations and settlements rather than planning issues, it illustrates the potential negative effect that even small data inconsistencies can have on modeling efforts.

Planning for large RTO regions is a very complex process that involves many assumptions about any number of planning scenarios. There may not be a one-size-fits-all approach to modeling the interconnected grid. However, more formal coordination of individual system expansion plans between individual regions and planning entities will likely lead to more effective and efficient transmission planning. Due to the complexity of the grid, coordination needs to focus on inter-regional projects and high voltage bulk power transmission planning. Further, data availability and consistency is almost certain to be an issue as larger planning processes like EISPC move forward. To the extent the Commission can help facilitate the sharing and accumulation of data for this endeavor, it will increase the efficiency and the likelihood of success of the inter-regional coordination efforts.

- **Will the interconnection-wide processes adopted pursuant to funding opportunities under the American Recovery and Reinvestment Act of 2009 result in an ongoing process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing sub-regional and regional planning processes? Will the scope and function of these interconnection-wide planning activities be sufficient to help address the concerns identified above? How will planning activities conducted on an interconnection-wide basis be integrated into the development of sub-regional and regional transmission plans and vice versa?**

One of the ARRA's goals is to improve the coordination and development of transmission planning and infrastructure construction utilizing input from all stakeholders, the RTOs, the utilities, the states and others.[2] With respect to interconnection-wide planning, this legislation should be given its chance before the Commission steps in with alternative interconnection-wide policies. Once established, this baseline will allow appropriate entities to develop their business case for appropriate projects, and states with siting authority will have a foundation of sound planning and stakeholder input to begin their respective review processes.

While it is still too early to definitively say whether the interconnection-wide transmission planning process will succeed, the OMS believes that participants will work in good faith to provide interconnection-wide plans for the benefit of the entire Eastern Interconnection. We also believe that the ISO/RTO entities in the regions will attempt to incorporate the interconnection-wide plans into their regional planning processes and filter such regional plans down to the sub-regional levels. As such, it is too early for the Commission to impose change on those efforts. While there may be a place for Commission-initiated policy improvements with respect to both regional and inter-regional transmission planning in some parts of the country,

[2] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068, at 5

interconnection-wide transmission planning efforts are in their nascent stages and should be given time to produce the expected results. As interconnection-wide transmission planning proceeds over the next few years, situations may arise that call for the Commission to nudge it in one way or the other, but doing that now would be disruptive rather than helpful.

- **How are reliability impact studies aligned with economic-based evaluations of sub-regional or regional projects and assessments of projects needed to satisfy renewable energy standards? If not aligned, how can reliability assessments and economic evaluations be aligned in order to better identify options that meet regional needs?**

Presently, in the Midwest ISO footprint there is a distinction with respect to eligibility for cost sharing and cost allocation between network upgrades, reliability projects and economic or commerce-oriented transmission facilities. At the time these cost allocation distinctions were adopted, they made sense because transmission planning and development was a function of reliability and economics. However, such distinctions fail to fully capture the dynamic nature of the transmission grid. For example, from electrical engineering and economic perspectives, a transmission line that fulfills these goals today may have less of an impact on these objectives in the future.

The OMS is not aware that the distinctions between reliability planning, generator interconnection planning, economic planning and renewable resource planning create any problems focusing strictly on the RTO's engineering planning and not cost allocation. The difficulty lies in defining into which single category of "need" particular projects with multiple uses and benefits must be slotted. Such single-purpose designations do not further efforts to meet some of these particular planning purposes and fairly allocating the costs of the projects that are determined to be needed.

The Midwest ISO also includes reliability testing as well as economic evaluations in its current sub-regional and regional planning processes. For example, the Midwest ISO's Regional Generation Outlet Study (RGOS) is intended to identify which states have renewable portfolio standards, how much renewable energy is needed in each state, potentially where the renewable energy would come from and the transmission needed to deliver that energy. However, at the present time, the Midwest ISO's tariff is not aligned with its planning efforts. Although the Midwest ISO and stakeholders are working diligently to derive a new rate tariff structure that does reflect today's drivers for transmission planning and construction, this tariff-planning misalignment is causing significant issues for proposed projects.

- **How should merchant and independent transmission projects be treated for purposes of regional transmission planning?**

All proposed transmission projects, including independent transmission projects, should be treated the same in regards to regional transmission planning. In short, all transmission proposals should be subject to the planning and study processes that are in place to ensure that the interconnection and operation of the proposed project will not detrimentally impact the grid. After all, there is only one interconnected transmission system in the eastern interconnection (even DC lines need to interconnect with AC lines at the ends of the lines.) As such, all new proposals should have to go through the processes in place to ensure the continuing integrity of the grid. No project should be approved before these processes are completed or any approvals should be conditioned on successful, timely completion of these processes.

- **Should they be required to participate in the planning process and, if so, at what point must they engage in the planning process?**

All transmission proposals need to be subject to the RTO planning and testing processes to ensure that the project can safely and reliably be interconnected and operate within the grid. Exceptions, for the most part, would not be in the public interest.

- **Do rights of first refusal for incumbent transmission owners unreasonably impede the development of merchant and independent transmission? If so, how can this impediment be addressed?**

Please see the answer to the next question.

- **Are there other barriers to the development of merchant and independent transmission in the transmission planning process?**

The Commission must ensure that, with respect to RTO transmission planning, there is no undue preference for incumbent or non-incumbent transmission providers or their affiliates. In particular, any rights of first refusal in RTO transmission planning practices could have a negative influence on the development of transmission lines. Accordingly, any such right should not be permitted to unduly discriminate against merchant and independent transmission.

The Midwest ISO Transmission Owners' Agreement ("TOA") establishes the Midwest ISO as the regional planning authority. The TOA states, "The Midwest ISO shall engage in such planning activities as are necessary to fulfill its obligations under this Agreement and the Transmission Tariff."[3] The TOA requires the Midwest ISO to produce a Midwest ISO Plan on a biennial basis.[4] The TOA provides that, "Approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities."[5] The TOA then requires that, "The affected Owner(s) shall make a good faith effort to design, certify, and build

[3] Agreement of the Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("TOA") Article Three, Section I, Para. C.
[4] TOA Appendix B, Article VI
[5] TOA Appendix B, Article VI

the designated facilities to fulfill the approved Midwest ISO Plan."[6] The TOA states that, "Each Owner shall use due diligence to construct transmission facilities as directed by the Midwest ISO [ ] subject to such siting, permitting, and environmental constraints as may be imposed by state, local, and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals."[7]

While it is not specifically identified as a "right of first refusal," the TOA includes the following language:

> Ownership and the responsibility to construct facilities which are connected to a single Owner's system belong to that Owner, and that Owner is responsible for maintaining such facilities. Ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Owner, unless such Owners otherwise agree, and the responsibility for maintaining such facilities belongs to the Owners of the facilities unless otherwise agreed by such Owners. Finally, ownership and the responsibility to construct facilities which are connected between an Owner(s)' system and a system or systems that are not part of the Midwest ISO belong to such Owner(s) unless the Owner(s) and the non-Midwest ISO party or parties otherwise agree; however, the responsibility to maintain the facilities remains with the Owner(s) unless otherwise agreed.[8]
>
> …,
>
> If the designated Owner is financially incapable of carrying out its construction responsibilities or would suffer demonstrable financial harm from such construction, alternate construction arrangements shall be identified. Depending on the specific circumstances, such alternate arrangements shall include solicitation of other Owners or others to take on financial and/or construction responsibilities. Third-parties shall be permitted and are encouraged to participate in the financing, construction and ownership of new transmission facilities as specified in the Midwest ISO Plan. In the event interest among other Owners or other entities is not sufficient to proceed, all Owners, subject to applicable regulatory requirements, shall be responsible for sharing in the financing of the project and/or hiring of a contractor(s) to construct the needed transmission facility; provided, however, the Owners' obligations under this sentence shall be subject to the Owners being satisfied that they will be compensated fully for their

[6] TOA Appendix B, Article VI
[7] TOA Article Four, Section 1, Para. C.
[8] TOA Appendix B, Article VI

investments and will not be subject to additional regulatory requirements, unless the Owners otherwise agree to waive either or both of these requirements.[9]

These provisions of the TOA, particularly the provision that provides existing transmission owners with the responsibility to construct facilities that are connected to the owner's system and the ownership rights to such facilities may be interpreted as a "right of first refusal". If interpreted in that manner, these provisions could act as a discriminatory barrier to independent and merchant transmission developers, since a developer that is not a designated "Owner" would only be able to construct in the Midwest ISO footprint when a designated "Owner" was financially incapable of doing so. While "third-parties" are permitted to participate in the financing, construction and ownership of new transmission facilities, such opportunity appears to arise only after the incumbent transmission owners have declined the opportunity. This right of first refusal may preclude the ability of independent transmission owners from competing with incumbents to build projects. Placing all transmission developers on equal footing could bring discipline to transmission costs through increased competition between developers.

In sum, the Commission must ensure that independent and merchant transmission developers can meaningfully participate in the RTO transmission planning process and that RTO practices do not unduly discriminate against any transmission owner with respect to transmission project development and ownership. Any provisions of RTO/ISO tariffs or agreements that frustrate this participation should be scrutinized and clarified.

- **Should similar assumptions regarding resource availability be used for generation owned by the transmission owner and merchant or independent developers?**

[9] TOA Appendix B, Article VI

All generation, regardless of whether it is affiliated with a transmission owner must be treated the same with respect to transmission planning.

- **Is the interconnection queue process hindering the ability to plan the transmission system to integrate new generation? Would any reforms to the Commission's interconnection procedures support efficient planning of the transmission system?**

Any interconnection queue system could possibly hinder the ability to perform meaningful planning if it is not designed correctly. For example, a highly permissive queue system (i.e., one with few requirements for getting and staying in the queue) may not have sufficient controls to discourage or prevent game playing and will likely be overwhelmed with projects, many of which have a very low likelihood of actually being built. This system will send an unclear signal to transmission planners that are attempting to incorporate likely generation development into future development scenarios. Conversely, a queue process that is too restrictive may impede the identification and development of necessary generation and may unduly restrict the types of entities engaging in such development. Where the balance lies between these competing positions is difficult to determine, and may be very different from region to region, where different policies and resources may take precedent. However, striking such a balance is worth the attention in order to facilitate planning efforts.

The Midwest ISO's interconnection queue process itself generally does not hinder transmission planning. However, there are a large percentage of the projects currently in the queue that will never be built. The fact that many of these interconnection decisions are in the hands of parties proposing new generation rather than the Midwest ISO and its member transmission owners, could be seen as too permissive and makes efficient transmission planning difficult. Conversely, parties are starting to see that interconnection queue rules may discourage or prevent settlements between generators and transmission owners for the purposes of facilitating interconnection agreements. The Midwest ISO has been working with a variety of stakeholders in an attempt to find the proper balance for its interconnection queue.

Determining and implementing an interconnection queue process that is "just right" is clearly a difficult but important element to the implementation of a successful transmission planning effort. The Midwest ISO's effort to address its interconnection queue problems should be given a chance to succeed. To that end, the Commission should follow the Midwest ISO's interconnection queue reform processes and give them a chance to succeed as well as coordinate with current planning efforts by CARP, UMTDI and MISO stakeholders before the Commission seeks to develop or impose any policies concerning the Midwest ISO's interconnection queue.

- **Should there be consistency in the way transmission providers treat demand resources, such as demand response, energy efficiency and distributed storage, in the transmission planning process? Are there preferred methods of modeling or otherwise accounting for demand resources in the planning process? Does the planning process investigate transmission needs at fine enough granularity to identify beneficial demand resource projects?**

The importance of demand response, energy efficiency, distributed storage, distributed resources and price responsive demand is rapidly increasing and these elements will likely have even greater impact in the future. Effective transmission planning must take these elements into account. Granular transmission planning that is able to account for these resources and elements as well as the regional and regulatory differences that may apply to them will be a positive development. The measurement and verification of these types of resources is an issue that will need to be addressed.

- **Are existing dispute resolution procedures in transmission provider tariffs adequate to address disputes that arise in the planning process?**

The Midwest ISO tariff provides effective alternative dispute resolution ("ADR") procedures available for disputes that arise in the planning process. These procedures have been called on sparingly and far more often with respect to market and settlement issues than planning issues. The OMS is not able to advise whether the ADR procedures are infrequently used because Midwest ISO market participants are not familiar with using these procedures or because the Midwest ISO has been successful in resolving most disputes at an early stage. It is the OMS' understanding that the Midwest ISO is considering modifications of the ADR procedures to improve stakeholder awareness of their availability, to make submission of a dispute easier, and to improve the fairness of the procedures.

B. Transmission Cost Allocation

The OMS recognizes the difficulty in lining up the causes and beneficiaries of a single line are often difficult (particularly in an alternating current grid), and that the benefits of any single line are likely to change over time, the CARP work group, the RECB Taskforce as well as the UMTDI are investigating different approaches

- **To the extent that a lack of up-front certainty about cost allocation is inhibiting transmission development, describe the relative impact of this concern on specific projects and as it relates to other impediments to development.**

State regulators have been told that the lack of up-front certainty about a cost allocation methodology is one of the greatest inhibitors to transmission development. Therefore state regulators and other policymakers are working together and are making a concerted effort to provide leadership to develop a workable and fair cost allocation methodology that will remove any barrier that the current methodology may create. CARP, RECB and UMTDI have cost allocation discussions as their main focus. The cost allocation methodologies that these processes work to develop will be evident in the near future.

- **Should processes be established to help stakeholders address cost allocation matters over larger geographic regions? What is an appropriate scope for**

those regions? Should they align with the regions for which planning is conducted?

Transmission costs should be allocated over the same geographic areas that are affected by the energy transactions. Since inter-regional energy transactions are common and the effects of those transactions are often broad, then costs should be allocated commensurate with the beneficial effects of the transaction. The main issue lies in how beneficiary and cost causers are defined, which is precisely the question that CARP, RECB and the other regional processes described above are attempting to define in their cost allocation discussions.

Inter-RTO cost allocations may be a more difficult issue. In the case of PJM and the Midwest ISO, scenarios arise where the cost causers/beneficiaries are located in one or both RTOs. However, since the current Midwest ISO/PJM inter-regional tariff is discounted to zero, there is no opportunity to charge the load or generators in the other RTO for the benefits of new transmission projects that are received. As such, with the prospect of billions of dollars of new transmission projects in an RTO with significant renewable energy resources, customers in one RTO will be unfairly subsidizing transactions in the other. The Commission should direct the RTOs to create an inter-regional tariff that charges the beneficiaries of the transmission system, regardless of which RTO they are located in.

- **Are there regional cost allocation methodologies outside RTOs, and broader regional cost allocation within RTOs, that should be considered or established? If so, how should this be done?**

In Order 890, the Commission required cost allocation proposals to be consistent with three general principles:

> First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we

> consider whether the proposal is generally supported by state authorities and participants across the region.[10]

Much has changed since the issuance of Order 890 and the Commission must now refine and clarify these general principles, particularly with inter-regional (e.g., inter-RTO) impacts in mind.

First, the Commission should reiterate its desire to have cost causers and beneficiaries pay for the transmission upgrades that are necessary to fulfill a variety of goals. A fair way to assign new transmission costs is to base assignments on an assessment of those market participants that cause the costs to be incurred and those market participants that benefit or will benefit from the new transmission.[11] As the 7th Circuit Court found, in order to be counted in the quantification, the purported benefits must be "articulable and plausible."[12] To that end, because the costs of new transmission are quantitative, the assessment of causation and beneficiaries should also be quantitative. While there are numerous just and reasonable ways to measure benefits and beneficiaries, the assessment should be a quantitative and demonstrable evaluation of incremental transmission facility impacts rather than just a qualitative assessment based on generalized assumptions or unsupported speculation. In this vein, the Commission must also be sure to address the non-quantifiable costs and benefits, which while difficult to fit into a numeric equation, definitely exist. Indeed, quantified information should typically be weighted more heavily than non-quantified information. After the quantifiable factual and

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[10] *Preventing Undue Discrimination and Preference in Transmission Service* 118 FERC ¶ 61,119, (2007) at P 559 ("Order 890")

[11] See *Illinois Commerce Commission, et al., v. Federal Energy Regulatory Commission, et al.*, ("7th Circuit Decision) at p. 10, where the Federal Court of Appeals for the 7th Circuit Court stated that, "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."

[12] 7th Circuit Decision, at p. 11, where the 7th Circuit Court allowed that, if purported benefits cannot be quantified, they must at least be "articulable" and have a "plausible reason."

policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

Second, the Commission has not heretofore given sufficient weight and sufficient clarity to its third general principle from Order 890. The Commission stated that it will "consider whether the [cost allocation] proposal is generally supported by state authorities and participants across the region."[13] However, the Commission has not yet clarified how it will judge whether there is general support by state authorities and participants across the region. Nor has the Commission established what the "region" is. The Commission has not yet clarified what weight it will give to general support by state authorities and participants across the region when it is evaluating a transmission cost allocation proposal.

With respect to transmission planning and cost allocation, the state commissions in the Midwest are primarily concerned with the following "regions": (1) the Midwest ISO region; (2) the PJM region; (3) the combined PJM and Midwest ISO region; (4) the combined Midwest ISO and SPP region; and (5) the combined Midwest ISO and non-Midwest ISO MAPP region.

With respect to the Midwest ISO region, the OMS formed the CARP working group to try to forge consensus (or at least a common understanding of differences in view) among the Midwest state regulators and policy-makers on difficult transmission planning and transmission cost allocation issues. The Midwest ISO stakeholders have a Planning Advisory Committee ("PAC") and a Regional Expansion Criteria and Benefits ("RECB") task force to develop proposals and provide advice to the Midwest ISO on transmission planning and transmission cost allocation issues. The OMS CARP and the Midwest ISO RECB are working together in an iterative manner on transmission cost allocation policy. The CARP and RECB processes are inclusive, transparent, and comprehensive.

[13] Order 890, at P 559

The OMS recommends that such arrangements serve as the model for cooperative and collaborative processes for transmission planning and transmission cost allocation. The Commission should declare that when cost allocation proposals (1) have been developed through such a cooperative and collaborative process and are generally supported by state authorities and participants; and (2) satisfy the cost causation - beneficiaries pay principle, the products and decisions produced by such process will receive great deference when submitted to the Commission for approval.

The OMS recommends that the Commission encourage the initiation of processes comparable to the CARP/PAC/RECB process for each of the other "regions" of interest to the Midwest state commissions, namely the (1) the PJM region; (2) the combined PJM and Midwest ISO region; (3) the combined Midwest ISO and SPP region; and (4) the combined Midwest ISO and non-Midwest ISO MAPP region.

As Steve Gaw pointed out in his September 10, 2009 Comments to the Commission in this proceeding, current RTO transmission planning does not deal well with the benefits of transmission projects to the extent those benefits flow to someone outside the RTO or outside the RTO's ability to bill for costs.[14] In some cases, benefits that accrue outside of the RTO responsible for the transmission -planning are simply ignored. In which case, beneficial projects are not built because the aggregate of the benefits that are counted does not equal or exceed the cost of the project. In other cases, the benefits that flow outside the RTO are counted and the electric consumers inside the RTO are expected to pay for the costs of the project that generates benefits to others merely because the RTO has no way of billing those others outside the RTO for the costs. Under such circumstances, projects will likely not be built because the intra-RTO

[14] Prepared Opening Remarks of Steve Gaw, Policy Director of the Wind Coalition, from September 10, 2009 Conference in Atlanta, GA under AD09-8

customers expected to pay will balk with protestations that the benefits <u>they receive</u> do not equal or exceed the costs they must pay. In either case, the needs of the larger inter-RTO region are not well served.

Ideally, the geographic coverage of transmission planning processes would be coterminous with the flow of benefits from the transmission projects examined in such planning process. So, whenever intra-RTO planning finds projects for which benefits flow outside the RTO, a joint planning process with that transmission planning entity and its state policy-makers and stakeholders must be initiated. In most cases, the flow of benefits from any particular project will be largely confined to the RTO's immediate neighbor. For this reason, the OMS recommends the establishment of standing joint planning processes with each of the Midwest ISO's neighboring transmission planning entities. However, in other cases, the benefits of a particular project may flow to even larger geographic regions, and, potentially, to the entire Eastern Interconnection. Therefore, the EISPC process may fulfill this needed element of transmission planning. The OMS is confident the Commission will be following the EISPC process to ensure that these broad geographic issues are sufficiently addressed in that process.

In the context of inter-RTO, and broader, transmission planning processes, the Commission should consider adopting rules or guidelines for inter-RTO transmission cost allocation. The guidelines must allow the RTO in whose footprint the transmission project will be built to assess costs, bill and collect from, the appropriate entities outside the RTO for costs of the project consistent with their benefits.

The state regulators are in the best position to judge the RTOs' beneficiary analyses. To the extent that a state's electric consumers will truly obtain benefits in accordance with the RTO's analysis, it can be expected that the state regulator will allow the recovery of the costs, provided that the costs are prudent and do not exceed the benefits that a project provides. Because, as explained above, if transmission costs are not reasonably allocated proportionate to benefits, it is likely that valuable transmission projects will not get built.

The Commission and the RTOs must work with the state commissions to establish how benefits of transmission projects will be measured and how the distribution of those benefits will be assessed.[15] The Commission and the RTOs must enable the state commissions to conduct their own independent analyses of benefits and beneficiaries. Unless sufficient data, information, analytical tools and capability to operate the analytical tools are provided to the state regulators, state regulators and the electric consumers they represent may balk at the prospect of incurring the costs of transmission projects.

- **Should each transmission provider hold an open season solicitation of interest for needed transmission projects identified through the transmission planning process in order to assist in cost allocation determinations?**

While an open season is unusual for electric operations, holding open season solicitations for proposed transmission projects has the potential to provide several benefits. In particular, an open season would likely provide information concerning the degree of interest in constructing the line and would assist in deciding questions regarding the size, type and timing of the project to best meet the requirements of the system. In instances where cost allocation uncertainty exists, holding open season solicitations could provide beneficial information regarding how many interconnecting projects are interested and how much energy these parties expect to transmit over the proposed transmission lines.

[15] The Commission stated in Order 890, "The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), 118 FERC 61,119, at P 560 (2007)

However, open season solicitations may be helpful in certain states or regions, but may conflict in others because different transmission owner business models are utilized. Therefore, any policies relating to open season solicitations should be mindful of any interconnection requirements or other similar efforts will have to be sufficiently flexible to account for these state and regional differences.

If the Commission were to pursue the concept of an open season process, the OMS would expect that all qualified developers would be permitted to compete to build the transmission projects that are determined to be necessary under the relevant regional or inter-regional transmission planning process. In most cases, the winners of the open season would have to qualify as a public utility under applicable state law and would need to be held to their commitments made in the open season bidding. A competitive process should produce the most cost-effective option for constructing a needed expansion of the transmission grid. A workable competitive process should be based on established criteria and standards for determining the most cost-effective bid such as:

(1) *Optimizing* (not maximizing) renewable integration;
(2) Ability to obtain timely permits and other authorizations;
(3) Capability to obtain timely financing; and
(4) Other relevant economic factors.

While transmission owners may be in a good position to establish these criteria, independent developers will likely be able to exert some competitive pressure on these transmission owners.. The state commissions, as facilitators of the regional or inter-regional planning and cost allocation process would be in a good position to decide which entity/entities could most cost-effectively construct and own the transmission project.

- **How can the customers that benefit from a particular facility be determined? Is there a preferred method? Should the method vary depending on the nature of the facility?**

It is difficult to determine the particular customers that benefit from a specific transmission facility. There does not seem to be a widely accepted, preferred method that is applied in the United States. The OMS CARP group has been examining various methods this year. In particular, the CARP group has been exploring the injection/withdrawal cost allocation methodology. One aspect of a flow-based, injection/withdrawal cost allocation method is that the determination of beneficiaries is dynamic. The underpinning of this methodology is to model the generalized access and use of the current network. The results of this model then guide the allocation of costs of future transmission facilities. The OMS CARP group expects to complete its evaluation of the injection/withdrawal approach by the end of 2009.

- **Should costs for base upgrades needed for existing reliability or economics be allocated differently than excess capacity expected to be needed for later developed resources? Should the allocation of costs for certain projects take into account the risk of under-subscribed "right sized" lines? If so, how should costs be re-allocated over time as such lines become subscribed by new customers?**

In a world where there is a significant need for new transmission, the distinction between base reliability and market-based projects is at a minimum blurred and in reality, no longer needed. Defining "right sized" as posed in the question is challenging. Because of the overall need for further transmission, which is expected to continue to grow into the future, it makes some sense to purposely right size facilities to avoid having to "tear down and rebuild" in the near future or to have to come back in the and create additional transmission corridors to serve that next increment of future customer growth.

However, the "right sizing" concept may pose challenges to regulators and policymakers. Whether to support and how to address deliberately over-sizing (assumed to equate to "right-sizing") proposed transmission projects is a thorny issue that speaks directly to state and federal policies and laws. For example, as discussed above, over-sizing a project proposal can put state regulators and policy-makers in a difficult position because most state law (and federal law) have various "public interest" and "used and useful" laws that typically discourage purposely constructing transmission capacity that will not be used when the line is put into service but is expected to be used in years to come. Such "right-sizing" of facilities is especially challenging for state regulators when the transmission project is over-built to serve projected needs in a different state. All of this is not to say that policies and laws may not start to be re-shaped to accommodate this change in thinking but it will not be done overnight.

- **Should cost allocation mechanisms continue to differ based on whether a project is deemed necessary based on reliability and adherence to approved reliability standards versus economic considerations?**

Reliability and economic considerations are both important reasons for transmission development, but this question fails to capture a significant reason why transmission development is necessary today. The fact is, most transmission development today is being discussed in order to fulfill policy considerations of encouraging and requiring additional renewable energy generation. Future development is likely going to be based on policy requirements to mitigate and reduce carbon dioxide emissions. While any development of new transmission will likely result in reliability and economic benefits, the cost allocation or cost recovery mechanisms may have to be focused on the policy reasons for the development.

Over time, any project will lower the risks of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefit. Given that both economic and reliability projects create costs and benefits on the integrated transmission system, transmission projects should be considered as a whole. Failing to acknowledge this new reality will allow some transmission projects to be constructed because they provide what are perceived to be "reliability benefits" while other "economic projects" are rejected for insufficient benefits despite allowing access to regions with lower cost generation resources. Such an outcome effectively imparts an artificial dividing line between projects that both contain an economic and reliability component. Furthermore, by reflexively approving every proposed reliability project, the Commission would potentially be ignoring more cost-effective solutions to serving incremental load such as targeted demand response or distributed generation.

- **How should non-quantifiable costs or benefits be identified, factored in or otherwise weighted?**

As noted above, the Commission must be sure to address the non-quantifiable costs and benefits, which while difficult to fit into a numeric equation, definitely exist. Indeed, non-quantified information should be factored in with quantified information. After the quantifiable factual and policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

- **Should the determination of beneficiaries of a transmission facility include generators as well as loads?**

Both generators and load benefit from the construction and operation of interconnecting transmission. In fact, it is difficult to imagine that an RTO could develop a workable or comprehensive set of benefits metrics that did not take into account the positive benefits obtained by generators (either existing or new) from new transmission projects. While it is basically true that, in the end, load pays for all transmission costs, allocating costs to generators proportionate to their benefits will better target the "correct" set of load as the generators attempt to recover their costs from their customers.[16]

[16] The OMS notes that the Commission has approved a cost allocation treatment that reimburses generators for 100% of qualifying interconnection costs in the ATC, ITC/METC, and ITC Midwest pricing zones of the

- **Should benefits be recalculated over time? Would recalculations negatively affect usage decisions?**

The distribution of beneficiaries should be re-examined from time-to-time. As the electric system and its uses change over time, the beneficiaries of transmission projects are also likely to change over time. Re-examination of beneficiaries would also help to eliminate free riders on the transmission system.

Adjustments to a project's cost allocation to reflect changes in the beneficiary distribution over time need not create uncertainty for project developers provided that there is certainty that the transmission project costs will be recovered from a cost-causer or a beneficiary. The "someone" need not be fixed over the life of the facility in order for the developer to have reasonable assurance about the opportunity to recover its costs.

II. CONCLUSION

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments regarding the issues discussed in these comments. The following members generally support these comments.

Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Montana Public Service Commission
North Dakota Public Service Commission
Public Utilities Commission of Ohio
Pennsylvania Public Utility Commission
South Dakota Public Utilities Commission

Midwest ISO. The recent Commission order ER09-1431 RECB Phase I solution did not supersede the previously approved methodology for these zones. To the extent that these OMS comments do not contradict the policies approved by the Commission for these pricing zones, the Michigan PSC supports the OMS comments in this regard. Through the ongoing cost allocation forums such as CARP and RECB Phase II, etc the Michigan PSC will be examining alternative methodologies.

Wisconsin Public Service Commission

The Illinois Commerce Commission and Missouri Public Service Commission abstained from the vote on these comments. The Manitoba Public Utilities Board did not participate in this pleading.

The Iowa Office of Consumer Advocate and the Minnesota Office of Energy Security, as associate members of the OMS, participated in these comments and generally support these comments. LISTING WILL REFLECT FINAL VOTES

Respectfully Submitted,

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Dated: November __, 2009

DRAFT November 09 DRAFT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Processes Under Order No. 890	))	Docket No. AD09-8-000

COMMENTS OF THE ORGANIZATION OF MISO STATES

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Request for Comments issued on October 8, 2009, the Organization of MISO States ("OMS") hereby submits the following comments regarding transmission planning processes and transmission cost allocation. The Commission originally requested that Comments be submitted no later than November 9, 2009, but subsequently extended that deadline to November 23, 2009.

I. DISCUSSION

The Commission seeks comments about how the current transmission planning processes and transmission cost allocation practices can be improved. The OMS supports the Commission's initiative to examine the effectiveness of existing transmission planning processes and cost allocation practices, particularly focusing on their regional and inter-regional aspects. The OMS cautions, however, that in its efforts to facilitate transmission investment, the Commission should not abandon principles that have served the industry well for decades. Given the high stakes for the nation in effective energy policy, the Commission must ensure that the processes being developed for regional and inter-regional transmission planning and the practices for transmission cost allocation provide for the nation's future energy needs, while recognizing individual states' interests in ensuring the reliable service to retail customers at reasonable rates. Given the geographic expanse, abundant resource endowment, unique electrical topology and illogical seams and borders of the Midwest ISO region, the OMS has a particular interest and great stake in the Commission's examination of transmission planning and transmission cost allocation policies.

In particular, the OMS recommends that the Commission recognize and support the ongoing initiatives of state regulators, state policymakers, RTOs and stakeholders in particular parts of the country to address and resolve transmission planning, development and cost allocation in ways acceptable to the various needs and multiple interests in those parts of the country. The need for improved transmission planning and fair cost allocation will only increase if policies require the development and construction of additional renewable energy and no-carbon or low-carbon generation. New transmission will be necessary to support these policy choices, which may require that new renewable power be transmitted -across long distances and multiple regions. In addition to improved transmission planning, fair transmission cost allocation in which cost causers and beneficiaries pay will become even more important. If the ongoing regional and inter-regional grass-roots efforts to develop policy solutions are able to produce broad consensus, or at least a common understanding regarding solutions, such solutions would create a strong foundation of industry certainty that would likely have more permanence than federally imposed solutions.

The OMS urges the Commission to act only in geographic areas and on issue areas where state and stakeholder action is absent or not working and Commission action may be necessary to stimulate progress. The Commission should allow the genuine state and regional-level efforts that have already been initiated to produce progress to proceed in those efforts. If, after a reasonable period of time without substantive results being produced by the existing cooperative efforts led by state policymakers, the Commission should consider issuing policy directives to address transmission planning and transmission cost allocation policies.

A. Transmission Planning Process

Historically, transmission planning and development focused on local reliability needs. However, the development of wholesale energy markets, the central dispatch of generation and the establishment of renewable energy portfolios have shifted this paradigm significantly. This requires transmission planners to perform reliability and economic analyses over much larger footprints. There is also the potential for Congress to enact climate change legislation that will also affect transmission planning and transmission system needs in significant ways. If climate legislation is enacted that restricts the emission of carbon dioxide, it is likely to have a transformational impact on the generation portfolio in many states over a very short period of time. Such new energy policy could result in the construction of new transmission lines to deliver significantly more energy from locations that are remote from load centers. Before the Commission proceeds to implement a large scale planning proposal of its own choosing, the Commission should be aware that states and regional state committees in some areas of the country have already begun the process of adapting to this new era of transmission planning. Indeed, the American Recovery and Reinvestment Act of 2009 ("ARRA") gives significant new impetus to creating a much larger and stronger collaborative approach among all stakeholders. These state and regional processes will lead to better transmission planning results than a federally-led process. These participants have an understanding of the local and regional concerns that are a key to the development of an effective transmission planning process.

At the state level, the OMS is aware of two significant efforts in the Midwest ISO footprint. First, the OMS has formed a Cost Allocation and Regional Planning ("CARP") initiative. In January 2009, this group of thirteen states in the Midwest ISO began an initiative working with the Midwest ISO to consider new cost allocation methods. Part of this initiative includes the development of indicative regional transmission plans tied to particular sets of scenarios and to consider a cost-allocation methodology. Significant computer modeling of generation expansion and needed transmission infrastructure have been part of the CARP initiative. Results from this initiative may be ready as soon as early 2010.

The second state policy-maker led approach involves the governors and state commissions from five states. Specifically, governors from Iowa, North and South Dakota, Minnesota and Wisconsin have formed the Upper Midwest Transmission Development Initiative ("UMTDI") with the goal of identifying necessary transmission infrastructure to deliver renewable energy from the western Midwest ISO footprint to states with renewable portfolio standard ("RPS") requirements. The UMTDI participants are also investigating the potential that the five states could develop transmission lines that would provide for the export of renewable energy beyond the borders of the states engaged in this effort. The UMTDI effort is expected to finish its work in 2010 and is also examining cost allocation issues.

The CARP and UMTDI initiatives show that state leadership is already taking action to adjust to new transmission planning needs, the realities of the ARRA funding impacts and the possibility of new federal energy policy.

The most recent development in regional transmission planning is the largest in scope, comprising the entire Eastern Interconnection. The ARRA directed $80 million to the Department of Energy ("DOE") to conduct resource assessments and provide technical assistance for interconnection-wide planning. The DOE released a Funding Opportunity Announcement ("FOA") in June of 2009 that identified distinct roles for transmission planners and engineers (Topic A) as well as a specified role for state policymakers and regulators (Topic B).[1]

After the release of the FOA, representatives from Governors' offices, state energy offices, regulatory commissions and other leaders throughout the eastern United States proposed to the DOE on September 14, 2009 under Topic B that an Eastern Interconnection States' Planning Council ("EISPC") be established. One of EISPC's major goals is to have state policymakers within the Eastern Interconnection create and establish a coordinated and consistent set of directives and analyses (e.g., assumptions and scenarios) for the modeling that will take place with this funding by the DOE-selected Topic-A entity. Of the 41 jurisdictions in the Eastern Interconnection, 38 have filed letters of support for the proposal. This represents an impressive and unprecedented level of cooperation among the states in the Eastern Interconnection.

EISPC, CARP and the UMTDI are prime examples of the role that state leadership can play in transmission planning and the development of new transmission infrastructure. There are a variety of reasons why these state and regional processes are likely to produce better results than a federally-led process. First, state commissions have the ultimate responsibility for retail electric rates and are therefore keenly aware of how the costs of interstate transmission lines will flow to ratepayers. Second, transmission planning must accommodate state choices with respect to generation portfolios and the complementary demand-side programs. Third, state regulators are better situated to identify and address transmission upgrades such that they do not harm or require excessive upgrades to existing facilities. Lastly, with siting authority and a local presence, the states are in a much better position to obtain buy-in from those who will be affected

[1] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068

most by new transmission lines. State-level decision-making allows for more complete public information, participation, credibility and public acceptance.

The OMS encourages the Commission to support CARP, UMTDI, EISPC and other similar initiatives that may follow these models. The OMS also recommends that the Commission facilitate the development of additional such state-led transmission planning and cost allocation stakeholder efforts by framing and clarifying the range of available policy options, particularly with respect to inter-regional issues.

- **Are existing transmission planning processes adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers? Should prospective transmission developers coordinate their projects in the interest of "right-sizing" facilities to make the best possible use of available corridors and minimize environmental impacts? If so, what process should govern the identification and selection of projects that affect multiple systems?**

The Midwest ISO's intra-RTO transmission planning process is generally working well and the above-mentioned interconnection-wide transmission planning efforts are too new to judge. While some of the inter-regional issues may ultimately be addressed by larger planning efforts like EISPC, the inter-regional transmission planning processes need to be improved and merit Commission guidance. The OMS offers recommendations in this regard below.

In general, RTO planning efforts focus on identifying the needs of the customers within the RTO and issuing a transmission expansion plan that identifies and evaluates options and proposes a solution to meet those intra-RTO needs. While some RTOs, including the Midwest ISO, participate in inter-RTO planning, those activities are often separate from the RTO's internal planning efforts. Internal RTO planning efforts are generally aimed at developing a transmission expansion plan with projects that the RTO directs to be built. As such, inter-RTO planning efforts are largely an academic exercise, with no apparent coordination among the various regions.

Sound transmission planning should provide an orderly structure to coordinate transmission projects not only to “right size” facilities but to make the best use of transmission corridors and not unduly create more corridors or new constraints. To the extent transmission developers are able to work cooperatively together, project costs may be shared among them which should reduce each developer’s project costs, thus benefitting the developers’ customers.

Ideally, the purpose of any proposed project would be clearly stated and transparent. Potential developers would, on their own, collaborate on selecting and locating potential joint projects and introducing the joint project into their ISO/RTO planning process. However, when collaboration fails, then the ISO/RTO planning process should identify project or project-portion alternatives that could reduce overall costs, “right size” facilities to meet identified needs over a larger footprint or more efficiently use transmission corridors. The states where the projects would be located should, in certain cases, have this information to conduct their state regulatory processes and the separate developers would need to explain why such efficiencies should not be approved. However, in the case of large inter-regional projects, State Regulators may not be able to justify such large projects for their own states. In these cases regional cooperation will be critical to ensure that all transmission upgrades are “right sized” for current needs, as well as the foreseeable future. The identification and adoption of fair cost allocation or cost recovery methodologies will be an important piece of this necessary regional and inter-regional cooperation.

While the RTOs, particularly the Midwest ISO, have undertaken cross-border transmission planning, very little in the way of practical projects has, to date, come from it. As such, improvements should be made regarding coordination and goals of such endeavors.

- **Are there adequate opportunities for stakeholders to participate in planning activities that span different regions, including for example those undertaken pursuant to bilateral agreements?**

There is adequate opportunity for stakeholders to participate in planning activities. Indeed, there are numerous stakeholder forums at PJM and the Midwest ISO associated with transmission planning. However, the reality is that the practical ability of many stakeholders, including retail customers and those representing the interests of retail customers is limited. Transmission planning and energy industry practices generally are evolving rapidly. The Commission must understand that stakeholder resources, particularly those within state commissions and other customer and public interest representatives, are spread thin. To the extent that the Commission can identify policies that will streamline and focus state and regional efforts, the scarce resources of the state commissions and the stakeholders can be more effectively focused.

While there is some transmission planning coordination between the Midwest ISO and PJM, the effort is largely an add-on to existing intra-RTO practices rather than being a combined transmission planning process. What is missing from the current inter-regional planning continuum is a coordinated process that involves the stakeholders of all affected RTO regions and a focus on issues impacting the regional and inter-regional RTO footprints. Furthermore, inter-regional involvement by stakeholders is very challenging, in that stakeholders would have to be involved in multiple ISO/RTO processes simultaneously. In particular, state commissions that straddle the PJM/Midwest ISO seam struggle to meaningfully participate in the transmission planning efforts of both the Midwest ISO, PJM and SPP. Similarly, state commissions not close to RTO seams do not have the resources to participate in inter-seam planning, even though such actions would impact these states as well.

In sum, the inter-RTO transmission planning processes merit additional Commission guidance and the OMS makes recommendations below in this regard.

- **Is there adequate coordination among planning entities to provide consistency in the data, assumptions and models being used in planning activities?**

The OMS is not in a position to directly answer this question. The planning entities are in the best position to respond about consistency between the planning entities. However, it is clear that PJM and the Midwest ISO can be subject to some modeling inconsistencies such as those illustrated by the recent market flow calculation controversy in Docket No. ND10-01-000. Part of this settlement proceeding may include an investigation of whether the calculation errors impacted loop flow assumptions, day-ahead unit commitment and/or Financial Transmission Rights /Auction Revenue Rights auction results. While that matter involves market operations and settlements rather than planning issues, it illustrates the potential negative effect that even small data inconsistencies can have on modeling efforts.

Planning for large RTO regions is a very complex process that involves many assumptions about any number of planning scenarios. There may not be a one-size-fits-all approach to modeling the interconnected grid. However, more formal coordination of individual system expansion plans between individual regions and planning entities will likely lead to more effective and efficient transmission planning. Due to the complexity of the grid, coordination needs to focus on inter-regional projects and high voltage bulk power transmission planning. Further, data availability and consistency is almost certain to be an issue as larger planning processes like EISPC move forward. To the extent the Commission can help facilitate the sharing and accumulation of data for this endeavor, it will increase the efficiency and the likelihood of success of the inter-regional coordination efforts.

- **Will the interconnection-wide processes adopted pursuant to funding opportunities under the American Recovery and Reinvestment Act of 2009 result in an ongoing process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing sub-regional and regional planning processes? Will the scope and function of these interconnection-wide planning activities be sufficient to help address the concerns identified above? How will planning activities conducted on an interconnection-wide basis be integrated into the development of sub-regional and regional transmission plans and vice versa?**

One of the ARRA's goals is to improve the coordination and development of transmission planning and infrastructure construction utilizing input from all stakeholders, the RTOs, the utilities, the states and others.[2] With respect to interconnection-wide planning, this legislation should be given its chance before the Commission steps in with alternative interconnection-wide policies. Once established, this baseline will allow appropriate entities to develop their business case for appropriate projects, and states with siting authority will have a foundation of sound planning and stakeholder input to begin their respective review processes.

While it is still too early to definitively say whether the interconnection-wide transmission planning process will succeed, the OMS believes that participants will work in good faith to provide interconnection-wide plans for the benefit of the entire Eastern Interconnection. We also believe that the ISO/RTO entities in the regions will attempt to incorporate the interconnection-wide plans into their regional planning processes and filter such regional plans down to the sub-regional levels. As such, it is too early for the Commission to impose change on those efforts. While there may be a place for Commission-initiated policy improvements with respect to both regional and inter-regional transmission planning in some parts of the country,

[2] U.S. Department of Energy Funding Opportunity Announcement DE-FOA-0000068, at 5

interconnection-wide transmission planning efforts are in their nascent stages and should be given time to produce the expected results. As interconnection-wide transmission planning proceeds over the next few years, situations may arise that call for the Commission to nudge it in one way or the other, but doing that now would be disruptive rather than helpful.

- **How are reliability impact studies aligned with economic-based evaluations of sub-regional or regional projects and assessments of projects needed to satisfy renewable energy standards? If not aligned, how can reliability assessments and economic evaluations be aligned in order to better identify options that meet regional needs?**

Presently, in the Midwest ISO footprint there is a distinction with respect to eligibility for cost sharing and cost allocation between network upgrades, reliability projects and economic or commerce-oriented transmission facilities. At the time these cost allocation distinctions were adopted, they made sense because transmission planning and development was a function of reliability and economics. However, such distinctions fail to fully capture the dynamic nature of the transmission grid. For example, from electrical engineering and economic perspectives, a transmission line that fulfills these goals today may have less of an impact on these objectives in the future.

The OMS is not aware that the distinctions between reliability planning, generator interconnection planning, economic planning and renewable resource planning create any problems focusing strictly on the RTO's engineering planning and not cost allocation. The difficulty lies in defining into which single category of "need" particular projects with multiple uses and benefits must be slotted. Such single-purpose designations do not further efforts to meet some of these particular planning purposes and fairly allocating the costs of the projects that are determined to be needed.

The Midwest ISO also includes reliability testing as well as economic evaluations in its current sub-regional and regional planning processes. For example, the Midwest ISO's Regional Generation Outlet Study (RGOS) is intended to identify which states have renewable portfolio standards, how much renewable energy is needed in each state, potentially where the renewable energy would come from and the transmission needed to deliver that energy. However, at the present time, the Midwest ISO's tariff is not aligned with its planning efforts. Although the Midwest ISO and stakeholders are working diligently to derive a new rate tariff structure that does reflect today's drivers for transmission planning and construction, this tariff-planning misalignment is causing significant issues for proposed projects.

- **How should merchant and independent transmission projects be treated for purposes of regional transmission planning?**

All proposed transmission projects, including independent transmission projects, should be treated the same in regards to regional transmission planning. In short, all transmission proposals should be subject to the planning and study processes that are in place to ensure that the interconnection and operation of the proposed project will not detrimentally impact the grid. After all, there is only one interconnected transmission system in the eastern interconnection (even DC lines need to interconnect with AC lines at the ends of the lines.) As such, all new proposals should have to go through the processes in place to ensure the continuing integrity of the grid. No project should be approved before these processes are completed or any approvals should be conditioned on successful, timely completion of these processes.

- **Should they be required to participate in the planning process and, if so, at what point must they engage in the planning process?**

All transmission proposals need to be subject to the RTO planning and testing processes to ensure that the project can safely and reliably be interconnected and operate within the grid. Exceptions, for the most part, would not be in the public interest.

- **Do rights of first refusal for incumbent transmission owners unreasonably impede the development of merchant and independent transmission? If so, how can this impediment be addressed?**

Please see the answer to the next question.

- **Are there other barriers to the development of merchant and independent transmission in the transmission planning process?**

The Commission must ensure that, with respect to RTO transmission planning, there is no undue preference for incumbent or non-incumbent transmission providers or their affiliates. In particular, any rights of first refusal in RTO transmission planning practices could have a negative influence on the development of transmission lines if an incumbent uses the right of first refusal to impede the development of transmission identified as needed in the RTO's planning processes. Conversely, if the right of first refusal is eliminated and independent or merchant transmission developers enter an incumbent's service territory to build with no regard to the local transmission's constraints, etc., this could disrupt the incumbent's transmission operations or reliability. Accordingly, any such right should not be permitted to unduly discriminate against merchant and independent transmission.

The Midwest ISO Transmission Owners' Agreement ("TOA") establishes the Midwest ISO as the regional planning authority. The TOA states, "The Midwest ISO shall engage in such planning activities as are necessary to fulfill its obligations under this Agreement and the Transmission Tariff."[3] The TOA requires the Midwest ISO to produce a Midwest ISO Plan on a

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[3] Agreement of the Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("TOA") Article Three, Section I, Para. C.

biennial basis.[4] The TOA provides that, "Approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities."[5] The TOA then requires that, "The affected Owner(s) shall make a good faith effort to design, certify, and build the designated facilities to fulfill the approved Midwest ISO Plan."[6] The TOA states that, "Each Owner shall use due diligence to construct transmission facilities as directed by the Midwest ISO [ ] subject to such siting, permitting, and environmental constraints as may be imposed by state, local, and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals."[7]

While it is not specifically identified as a "right of first refusal," the TOA includes the following language:

> Ownership and the responsibility to construct facilities which are connected to a single Owner's system belong to that Owner, and that Owner is responsible for maintaining such facilities. Ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Owner, unless such Owners otherwise agree, and the responsibility for maintaining such facilities belongs to the Owners of the facilities unless otherwise agreed by such Owners. Finally, ownership and the responsibility to construct facilities which are connected between an Owner(s)' system and a system or systems that are not part of the Midwest ISO belong to such Owner(s) unless the Owner(s) and the non-Midwest ISO party or parties otherwise agree; however, the responsibility to maintain the facilities remains with the Owner(s) unless otherwise agreed.[8]
>
> …,
>
> If the designated Owner is financially incapable of carrying out its construction responsibilities or would suffer demonstrable financial harm from such construction, alternate construction arrangements shall be identified. Depending on the specific circumstances, such alternate arrangements shall include

[4] TOA Appendix B, Article VI
[5] TOA Appendix B, Article VI
[6] TOA Appendix B, Article VI
[7] TOA Article Four, Section 1, Para. C.
[8] TOA Appendix B, Article VI

> solicitation of other Owners or others to take on financial and/or construction responsibilities. Third-parties shall be permitted and are encouraged to participate in the financing, construction and ownership of new transmission facilities as specified in the Midwest ISO Plan. In the event interest among other Owners or other entities is not sufficient to proceed, all Owners, subject to applicable regulatory requirements, shall be responsible for sharing in the financing of the project and/or hiring of a contractor(s) to construct the needed transmission facility; provided, however, the Owners' obligations under this sentence shall be subject to the Owners being satisfied that they will be compensated fully for their investments and will not be subject to additional regulatory requirements, unless the Owners otherwise agree to waive either or both of these requirements.[9]

These provisions of the TOA, particularly the provision that provides existing transmission owners with the responsibility to construct facilities that are connected to the owner's system and the ownership rights to such facilities may be interpreted as a "right of first refusal". If interpreted in that manner, these provisions could act as a discriminatory barrier to independent and merchant transmission developers, since a developer that is not a designated "Owner" would only be able to construct in the Midwest ISO footprint when a designated "Owner" was financially incapable of or, otherwise, declined to doing so. While "third-parties" are permitted to participate in the financing, construction and ownership of new transmission facilities, such opportunity appears to arise only after the incumbent transmission owners have declined the opportunity. This right of first refusal may preclude the ability of independent transmission owners from competing with incumbents to build projects. Placing all transmission developers on equal footing could bring discipline to transmission costs through increased competition between developers.

In sum, the Commission must ensure that independent and merchant transmission developers can meaningfully participate in the RTO transmission planning process and that RTO practices do not unduly discriminate against any transmission owner with respect to transmission

[9] TOA Appendix B, Article VI

project development and ownership. Any provisions of RTO/ISO tariffs or agreements that frustrate this participation should be scrutinized and clarified.

- **Should similar assumptions regarding resource availability be used for generation owned by the transmission owner and merchant or independent developers?**

All generation, regardless of whether it is affiliated with a transmission owner must be treated the same with respect to transmission planning.

- **Is the interconnection queue process hindering the ability to plan the transmission system to integrate new generation? Would any reforms to the Commission's interconnection procedures support efficient planning of the transmission system?**

Any interconnection queue system could possibly hinder the ability to perform meaningful planning if it is not designed correctly. For example, a highly permissive queue system (i.e., one with few requirements for getting and staying in the queue) may not have sufficient controls to discourage or prevent game playing and will likely be overwhelmed with projects, many of which have a very low likelihood of actually being built. This system will send an unclear signal to transmission planners that are attempting to incorporate likely generation development into future development scenarios. Conversely, a queue process that is too restrictive may impede the identification and development of necessary generation and may unduly restrict the types of entities engaging in such development. Where the balance lies between these competing positions is difficult to determine, and may be very different from region to region, where different policies and resources may take precedent. However, striking such a balance is worth the attention in order to facilitate planning efforts.

The Midwest ISO's interconnection queue process itself generally does not hinder transmission planning. However, there are a large percentage of the projects currently in the queue that will never be built. The fact that many of these interconnection decisions are in the hands of parties proposing new generation rather than the Midwest ISO and its member transmission owners, could be seen as too permissive and makes efficient transmission planning difficult. Conversely, parties are starting to see that interconnection queue rules may discourage or prevent settlements between generators and transmission owners for the purposes of facilitating interconnection agreements. The Midwest ISO has been working with a variety of stakeholders in an attempt to find the proper balance for its interconnection queue.

Determining and implementing an interconnection queue process that is "just right" is clearly a difficult but important element to the implementation of a successful transmission planning effort. The Midwest ISO's effort to address its interconnection queue problems should be given a chance to succeed. To that end, the Commission should follow the Midwest ISO's interconnection queue reform processes and give them a chance to succeed as well as coordinate with current planning efforts by CARP, UMTDI and MISO stakeholders before the Commission seeks to develop or impose any policies concerning the Midwest ISO's interconnection queue.

- **Should there be consistency in the way transmission providers treat demand resources, such as demand response, energy efficiency and distributed storage, in the transmission planning process? Are there preferred methods of modeling or otherwise accounting for demand resources in the planning process? Does the planning process investigate transmission needs at fine enough granularity to identify beneficial demand resource projects?**

The importance of demand response, energy efficiency, distributed storage, distributed resources and price responsive demand is rapidly increasing and these elements will likely have even greater impact in the future. Effective transmission planning must take these elements into account. Granular transmission planning that is able to account for these resources and elements as well as the regional and regulatory differences that may apply to them will be a positive development. The measurement and verification of these types of resources is an issue that will need to be addressed.

- **Are existing dispute resolution procedures in transmission provider tariffs adequate to address disputes that arise in the planning process?**

The Midwest ISO tariff provides effective alternative dispute resolution ("ADR") procedures available for disputes that arise in the planning process. These procedures have been called on sparingly and far more often with respect to market and settlement issues than planning issues. The OMS is not able to advise whether the ADR procedures are infrequently used because Midwest ISO market participants are not familiar with using these procedures or because the Midwest ISO has been successful in resolving most disputes at an early stage. It is the OMS' understanding that the Midwest ISO is considering modifications of the ADR procedures to improve stakeholder awareness of their availability, to make submission of a dispute easier, and to improve the fairness of the procedures.

B. Transmission Cost Allocation

The OMS recognizes that ~~the difficulty in~~ lining up the causes and beneficiaries of a single line are often difficult (particularly in an alternating current grid), and that the benefits of any single line are likely to change over time. T~~, t~~he CARP work group, the RECB Taskforce as well as the UMTDI are investigating different approaches

- **To the extent that a lack of up-front certainty about cost allocation is inhibiting transmission development, describe the relative impact of this concern on specific projects and as it relates to other impediments to development.**

State regulators have been told that the lack of up-front certainty about a cost allocation methodology is one of the greatest inhibitors to transmission development. Therefore state regulators and other policymakers are working together and are making a concerted effort to provide leadership to develop a workable and fair cost allocation methodology that will remove any barrier that the current methodology may create. CARP, RECB and UMTDI have cost allocation discussions as their main focus. The cost allocation methodologies that these processes work to develop will be evident in the near future.

- **Should processes be established to help stakeholders address cost allocation matters over larger geographic regions? What is an appropriate scope for those regions? Should they align with the regions for which planning is conducted?**

Transmission costs should be allocated over the same geographic areas that are affected by the energy transactions. Since inter-regional energy transactions are common and the effects of those transactions are often broad, then costs should be allocated commensurate with the beneficial effects of the transaction. The main issue lies in how beneficiary and cost causers are defined, which is precisely the question that CARP, RECB and the other regional processes described above are attempting to define in their cost allocation discussions.

Inter-RTO cost allocations may be a more difficult issue. In the case of PJM and the Midwest ISO, scenarios arise where the cost causers/beneficiaries are located in one or both RTOs. However, since the current Midwest ISO/PJM inter-regional tariff is discounted to zero, there is no opportunity to charge the load or generators in the other RTO for the benefits of new transmission projects that are received. As such, with the prospect of billions of dollars of new transmission projects in an RTO with significant renewable energy resources, customers in one RTO will be unfairly subsidizing transactions in the other. The Commission should direct the RTOs to create an inter-regional tariff that charges the beneficiaries of the transmission system, regardless of which RTO they are located in.

- **Are there regional cost allocation methodologies outside RTOs, and broader regional cost allocation within RTOs, that should be considered or established? If so, how should this be done?**

In Order 890, the Commission required cost allocation proposals to be consistent with three general principles:

> First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region.[10]

Much has changed since the issuance of Order 890 and the Commission must now refine and clarify these general principles, particularly with inter-regional (e.g., inter-RTO) impacts in mind.

First, the Commission should reiterate its desire to have cost causers and beneficiaries pay for the transmission upgrades that are necessary to fulfill a variety of goals. A fair way to assign new transmission costs is to base assignments on an assessment of those market participants that cause the costs to be incurred and those market participants that benefit or will benefit from the new transmission.[11] As the 7th Circuit Court found, in order to be counted in the quantification, the purported benefits must be "articulable and plausible."[12] To that end, because the costs of new transmission are quantitative, the assessment of causation and beneficiaries should also be quantitative. While there are numerous just and reasonable ways to measure benefits and beneficiaries, the assessment should be a quantitative and demonstrable evaluation of incremental transmission facility impacts rather than just a qualitative assessment based on generalized assumptions or unsupported speculation. In this vein, the Commission must also be sure to address the non-quantifiable costs and benefits, which while difficult to fit into a numeric equation, definitely exist. Indeed, quantified information should typically be

[10] *Preventing Undue Discrimination and Preference in Transmission Service* 118 FERC ¶ 61,119, (2007) at P 559 ("Order 890")

[11] See *Illinois Commerce Commission, et al., v. Federal Energy Regulatory Commission, et al.*, ("7th Circuit Decision) at p. 10, where the Federal Court of Appeals for the 7th Circuit Court stated that, "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."

[12] 7th Circuit Decision, at p. 11, where the 7th Circuit Court allowed that, if purported benefits cannot be quantified, they must at least be "articulable" and have a "plausible reason."

weighted more heavily than non-quantified information. After the quantifiable factual and policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

Second, the Commission has not heretofore given sufficient weight and sufficient clarity to its third general principle from Order 890. The Commission stated that it will "consider whether the [cost allocation] proposal is generally supported by state authorities and participants across the region."[13] However, the Commission has not yet clarified how it will judge whether there is general support by state authorities and participants across the region. Nor has the Commission established what the "region" is. The Commission has not yet clarified what weight it will give to general support by state authorities and participants across the region when it is evaluating a transmission cost allocation proposal.

With respect to transmission planning and cost allocation, the state commissions in the Midwest are primarily concerned with the following "regions": (1) the Midwest ISO region; (2) the PJM region; (3) the combined PJM and Midwest ISO region; (4) the combined Midwest ISO and SPP region; and (5) the combined Midwest ISO and non-Midwest ISO MAPP region.

With respect to the Midwest ISO region, the OMS formed the CARP working group to try to forge consensus (or at least a common understanding of differences in view) among the Midwest state regulators and policy-makers on difficult transmission planning and transmission cost allocation issues. The Midwest ISO stakeholders have a Planning Advisory Committee ("PAC") and a Regional Expansion Criteria and Benefits ("RECB") task force to develop proposals and provide advice to the Midwest ISO on transmission planning and transmission cost allocation issues. The OMS CARP and the Midwest ISO RECB are working together in an

[13] Order 890, at P 559

iterative manner on transmission cost allocation policy. The CARP and RECB processes are inclusive, transparent, and comprehensive.

The OMS recommends that such arrangements serve as the model for cooperative and collaborative processes for transmission planning and transmission cost allocation. The Commission should declare that when cost allocation proposals (1) have been developed through such a cooperative and collaborative process and are generally supported by state authorities and participants; and (2) satisfy the cost causation - beneficiaries pay principle, the products and decisions produced by such process will receive great deference when submitted to the Commission for approval.

The OMS recommends that the Commission encourage the initiation of processes comparable to the CARP/PAC/RECB process for each of the other "regions" of interest to the Midwest state commissions, namely the (1) the PJM region; (2) the combined PJM and Midwest ISO region; (3) the combined Midwest ISO and SPP region; and (4) the combined Midwest ISO and non-Midwest ISO MAPP region.

As Steve Gaw pointed out in his September 10, 2009 Comments to the Commission in this proceeding, current RTO transmission planning does not deal well with the benefits of transmission projects to the extent those benefits flow to someone outside the RTO or outside the RTO's ability to bill for costs.[14] In some cases, benefits that accrue outside of the RTO responsible for the transmission planning are simply ignored. In which case, beneficial projects are not built because the aggregate of the benefits that are counted does not equal or exceed the cost of the project. In other cases, the benefits that flow outside the RTO are counted and the electric consumers inside the RTO are expected to pay for the costs of the project that generates

[14] Prepared Opening Remarks of Steve Gaw, Policy Director of the Wind Coalition, from September 10, 2009 Conference in Atlanta, GA under AD09-8

benefits to others merely because the RTO has no way of billing those others outside the RTO for the costs. Under such circumstances, projects will likely not be built because the intra-RTO customers expected to pay will balk with protestations that the benefits they receive do not equal or exceed the costs they must pay. In either case, the needs of the larger inter-RTO region are not well served.

Ideally, the geographic coverage of transmission planning processes would be coterminous with the flow of benefits from the transmission projects examined in such planning process. So, whenever intra-RTO planning finds projects for which benefits flow outside the RTO, a joint planning process with that transmission planning entity and its state policy-makers and stakeholders must be initiated. In most cases, the flow of benefits from any particular project will be largely confined to the RTO's immediate neighbor. For this reason, the OMS recommends the establishment of standing joint planning processes with each of the Midwest ISO's neighboring transmission planning entities. However, in other cases, the benefits of a particular project may flow to even larger geographic regions, and, potentially, to the entire Eastern Interconnection. Therefore, the EISPC process may fulfill this needed element of transmission planning. The OMS is confident the Commission will be following the EISPC process to ensure that these broad geographic issues are sufficiently addressed in that process.

In the context of inter-RTO, and broader, transmission planning processes, the Commission should consider adopting rules or guidelines for inter-RTO transmission cost allocation. The guidelines must allow the RTO in whose footprint the transmission project will be built to assess costs, bill and collect from, the appropriate entities outside the RTO for costs of the project consistent with their benefits.

The state regulators are in the best position to judge the RTOs' beneficiary analyses. To the extent that a state's electric consumers will truly obtain benefits in accordance with the RTO's analysis, it can be expected that the state regulator will allow the recovery of the costs, provided that the costs are prudent and do not exceed the benefits that a project provides. Because, as explained above, if transmission costs are not reasonably allocated proportionate to benefits, it is likely that valuable transmission projects will not get built.

The Commission and the RTOs must work with the state commissions to establish how benefits of transmission projects will be measured and how the distribution of those benefits will be assessed.[15] The Commission and the RTOs must enable the state commissions to conduct their own independent analyses of benefits and beneficiaries. Unless sufficient data, information, analytical tools and capability to operate the analytical tools are provided to the state regulators, state regulators and the electric consumers they represent may balk at the prospect of incurring the costs of transmission projects.

- **Should each transmission provider hold an open season solicitation of interest for needed transmission projects identified through the transmission planning process in order to assist in cost allocation determinations?**

While an open season is unusual for electric operations, holding open season solicitations for proposed transmission projects has the potential to provide several benefits. In particular, an open season would likely provide information concerning the degree of interest in constructing the line and would assist in deciding questions regarding the size, type and timing of the project to best meet the requirements of the system. In instances where cost allocation uncertainty exists, holding open season solicitations could provide beneficial information regarding how

[15] The Commission stated in Order 890, "The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), 118 FERC 61,119, at P 560 (2007)

many interconnecting projects are interested and how much energy these parties expect to transmit over the proposed transmission lines.

However, open season solicitations may be helpful in certain states or regions, but may conflict in others because different transmission owner business models are utilized. Therefore, any policies relating to open season solicitations should be mindful of any interconnection requirements or other similar efforts will have to be sufficiently flexible to account for these state and regional differences.

If the Commission were to pursue the concept of an open season process, the OMS would expect that all qualified developers would be permitted to compete to build the transmission projects that are determined to be necessary under the relevant regional or inter-regional transmission planning process. In most cases, the winners of the open season would have to qualify as a public utility under applicable state law and would need to be held to their commitments made in the open season bidding. A competitive process should produce the most cost-effective option for constructing a needed expansion of the transmission grid. A workable competitive process should be based on established criteria and standards for determining the most cost-effective bid such as:

(1) *Optimizing* (not maximizing) renewable integration;
(2) Ability to obtain timely permits and other authorizations;
(3) Capability to obtain timely financing; and
(4) Other relevant economic factors.

While transmission owners may be in a good position to establish these criteria, independent developers will likely be able to exert some competitive pressure on these transmission owners.. The state commissions, as facilitators of the regional or inter-regional planning and cost allocation process would be in a good position to decide which entity/entities could most cost-effectively construct and own the transmission project.

- **How can the customers that benefit from a particular facility be determined? Is there a preferred method? Should the method vary depending on the nature of the facility?**

It is difficult to determine the particular customers that benefit from a specific transmission facility. There does not seem to be a widely accepted, preferred method that is applied in the United States. The OMS CARP group has been examining various methods this year. In particular, the CARP group has been exploring the injection/withdrawal cost allocation methodology. One aspect of a flow-based, injection/withdrawal cost allocation method is that the determination of beneficiaries is dynamic. The underpinning of this methodology is to model the generalized access and use of the current network. The results of this model then guide the allocation of costs of future transmission facilities. The OMS CARP group expects to complete its evaluation of the injection/withdrawal approach by the end of 2009.

- **Should costs for base upgrades needed for existing reliability or economics be allocated differently than excess capacity expected to be needed for later developed resources? Should the allocation of costs for certain projects take into account the risk of under-subscribed "right sized" lines? If so, how should costs be re-allocated over time as such lines become subscribed by new customers?**

In a world where there is a significant need for new transmission, the distinction between base reliability and market-based projects is at a minimum blurred and in reality, no longer needed. Defining "right sized" as posed in the question is challenging. Because of the overall need for further transmission, which is expected to continue to grow into the future, it makes some sense to purposely right size facilities to avoid having to "tear down and rebuild" in the near future or to have to come back in the and create additional transmission corridors to serve that next increment of future customer growth.

However, the "right sizing" concept may pose challenges to regulators and policymakers. Whether to support and how to address deliberately over-sizing (assumed to equate to "right-sizing") proposed transmission projects is a thorny issue that speaks directly to state and federal policies and laws. For example, as discussed above, over-sizing a project proposal can put state regulators and policy-makers in a difficult position because most state law (and federal law) have various "public interest" and "used and useful" laws that typically discourage purposely constructing transmission capacity that will not be used when the line is put into service but is expected to be used in years to come. Such "right-sizing" of facilities is especially challenging for state regulators when the transmission project is over-built to serve projected needs in a different state. All of this is not to say that policies and laws may not start to be re-shaped to accommodate this change in thinking but it will not be done overnight.

- **Should cost allocation mechanisms continue to differ based on whether a project is deemed necessary based on reliability and adherence to approved reliability standards versus economic considerations?**

Reliability and economic considerations are both important reasons for transmission development, but this question fails to capture a significant reason why transmission development is necessary today. The fact is, most transmission development today is being discussed in order to fulfill policy considerations of encouraging and requiring additional renewable energy generation. Future development is likely going to be based on policy requirements to mitigate and reduce carbon dioxide emissions. While any development of new transmission will likely result in reliability and economic benefits, the cost allocation or cost recovery mechanisms may have to be focused on the policy reasons for the development.

Over time, any project will lower the risks of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefit. Given that both economic and reliability projects create costs and benefits on the integrated transmission system, transmission projects should be considered as a whole. Failing to acknowledge this new reality will allow some transmission projects to be constructed because they provide what are perceived to be "reliability benefits" while other "economic projects" are rejected for insufficient benefits despite allowing access to regions with lower cost generation resources. Such an outcome effectively imparts an artificial dividing line between projects that both contain an economic and reliability component. Furthermore, by reflexively approving every proposed reliability project, the Commission would potentially be ignoring more cost-effective solutions to serving incremental load such as targeted demand response or distributed generation.

- **How should non-quantifiable costs or benefits be identified, factored in or otherwise weighted?**

As noted above, the Commission must be sure to evenly address the existing non-quantifiable costs and benefits, which while difficult to fit into a numeric equation~~, definitely exist~~. Indeed, non-quantified information should be factored in with quantified information. After the quantifiable factual and policy information is presented and vetted, non-quantifiable costs or benefits should be recognized and factored into the support or opposition to a case.

- **Should the determination of beneficiaries of a transmission facility include generators as well as loads?**

Both generators and load benefit from the construction and operation of interconnecting transmission. In fact, it is difficult to imagine that an RTO could develop a workable or comprehensive set of benefits metrics that did not take into account the positive benefits obtained by generators (either existing or new) from new transmission projects. While it is basically true that, in the end, load pays for all transmission costs, allocating costs to generators proportionate to their benefits will better target the "correct" set of load as the generators attempt to recover their costs from their customers.[16]

- **Should benefits be recalculated over time? Would recalculations negatively affect usage decisions?**

The distribution of beneficiaries should be re-examined from time-to-time. As the electric system and its uses change over time, the beneficiaries of transmission projects are also likely to change over time. Re-examination of beneficiaries would also help to eliminate free riders on the transmission system.

Adjustments to a project's cost allocation to reflect changes in the beneficiary distribution over time need not create uncertainty for project developers provided that there is certainty that the transmission project costs will be recovered from a cost-causer or a beneficiary. The "someone" need not be fixed over the life of the facility in order for the developer to have reasonable assurance about the opportunity to recover its costs.

II. CONCLUSION

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments regarding the issues discussed in these comments. The following members generally support these comments.

Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Michigan Public Service Commission

[16] The OMS notes that the Commission has approved a cost allocation treatment that reimburses generators for 100% of qualifying interconnection costs in the ATC, ITC/METC, and ITC Midwest pricing zones of the Midwest ISO. The recent Commission order ER09-1431 RECB Phase I solution did not supersede the previously approved methodology for these zones. To the extent that these OMS comments do not contradict the policies approved by the Commission for these pricing zones, the Michigan PSC supports the OMS comments in this regard. Through the ongoing cost allocation forums such as CARP and RECB Phase II, etc the Michigan PSC will be examining alternative methodologies.

Minnesota Public Utilities Commission
Montana Public Service Commission
North Dakota Public Service Commission
Public Utilities Commission of Ohio
Pennsylvania Public Utility Commission
South Dakota Public Utilities Commission
Wisconsin Public Service Commission

The Illinois Commerce Commission and Missouri Public Service Commission abstained from the vote on these comments. The Manitoba Public Utilities Board did not participate in this pleading.

The Iowa Office of Consumer Advocate and the Minnesota Office of Energy Security, as associate members of the OMS, participated in these comments and generally support these comments. LISTING WILL REFLECT FINAL VOTES

Respectfully Submitted,

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Dated: November __, 2009