Planning Advisory Committee
March 5, 2008 – Meeting Minutes
Lakeside Corporate Center

Meeting called to order at 11:35 am.

Roll Call

Chair Julie Voeck	Mark Wehlage, VITO Sector
*Kavita Maini, End User Sector	Mike Shields, Power Marketer Sector
*Patrick Gerum, Coop/Muni/TDU Alternate	Flora Flygt, MSAT Sector
*Beth Soholt, Environmental Sector	*Don Neumeyer, Regulatory Sector (proxy for Daniel Ebert)

Attendees

Lin Franks, IPL	Jeremiah Doner, Midwest ISO
Jennifer Curran, Midwest ISO	Jim Musial, Detroit Edison
Mike Shields, DTE Energy	Dale Osborn, Midwest ISO
John Bloemer, Duke Energy	Ed Kirschner, Duke Energy
Chris Miller, FERC	David Sapper, CES
Clair Moeller, Midwest ISO	Flora Flygt, ATC
Barbara Smith, IN Office/Utility Consumer	Van Greening, ITC
Kevin Murray, CMTC	Rich Cottrell, Consumers Energy
*Hamish Wong, WPS	*Jennifer Easler, IA OCA
*Stewart Bayer, NIPSCO	*David Nick, DTE
*Megan Wisersky, MGE	*Patrick Gerum, WE Energies
*Parveen Baig, IA IUB	*Jennifer Ayers-Brasher, EON
*Don Neumeyer, WI PSC	*Jon Riley, AEP
*Jason Cross, OH PUC	*William VanderLaan, ILL ICC
*George Kogut, FE	*Mike Proctor, MO PSC
*Jeff Eddy, ITC	*Purvi Patel, ITC
*Gary Fuerst, FE	*Wenchun Zhu, ATC
*Andy Dotterweich, Consumers Energy	*George Stevens, IN URC
*Scott Deffenderfer, Ameren	*John Dwyer, IA OCA
*Kavita Maini, KM Energy	*Antonio Sammut, ITC
*Matt Holtz, NIPSCO	*Sally Talberg, MI PSC
*Carl Bridenbaugh, FE	*Gary Brownfield, Ameren
*Alison Johnson, Midwest ISO	*Mark Kempker, IPL
*Chancy Bittner, IUB	*Ed Pfeiffer, Ameren
*Kent Kajula, DTE	*Steve Rose, CWLP
*Jeff Hackman, Ameren	*John Kayser, Alliant
*Jeff Eddy, ITC	*Al Such, IPL
*Wanda Jones, MI PSC	*Steve Leovy
Jarrad Miland, Midwest ISO	

*Participation by phone

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Approval of Meeting Minutes
The February 6, 2008 meeting minutes were approved with the addition of Steve Gaarde's attendance.

Midwest ISO Planning Objectives Discussion
Jennifer Curran discussed the *Midwest ISO Planning Approach* presentation.

From the Midwest ISO perspective, what does "value" mean?
We're looking at Midwest ISO stakeholders, focusing on the end-use consumer, and looking at other benefits to consumers in the footprint. The challenge is breaking apart and identifying ways to maximize benefits to all parties.
How will you avoid competing objectives?
We're looking at many things and trying to reveal questions and the answers to those questions; it isn't the same as building a plan that supports one or the other. We have to look at all facets, do analysis, put on the table and have discussions, ultimately moving to a recommendation.

On page 5, what is meant by "increased transmission build" in the first bullet point?
More – faster or higher voltage; something different or more in terms of amount than we see today.
Why is that issue listed when it should be a given?
The issue is not everyone agrees with how much more transmission means. Some are concerned with a buildout of transmission that will be disproportionately costed to them. We don't see as *any,* we see as *how much*. Regulators have to agree with what we're going to build.
When going before docket, you have to have documentation. As an independent engineer, we can't accept that it's automatic. You have to have a business case if you're going to do anything, particularly in a proceeding for imminent domain.

On page 6 regarding the current paradigm comment, you need to add using demand response. Also, in the power marketing sector you think you should be using the resource planning approach? Looking at transmission as an alternative to generation, you need to look at the capacity of full Integrated Resource Plan (IRP) type of approach.
We will say explicitly in the next couple of slides that we're not doing IRP type planning.
We're spending lots of money doing demand side management and burning up MWh. It might be more cost effective to go after losses and be more green on the transmission side than chase a few dollars on the demand side.
The thought today is that we have higher reserve margins and lower transfer capability. By improving transfer capability, could we reduce reserve margins? That's the question we're trying to answer.
Thinking about the slide conceptually, Midwest ISO is already projecting that it will significantly reduce contingency reserves with ASM and contingency reserve sharing. I think the number projected is around 2100 MW. You get down to 1500 MW and I think

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that is the minimum level to recognize a N-1 contingency. In theory, it suggests that there's only about 600 MW of reduced contingency reserves.
We're trying not to confuse operating and planning reserves. Looking at the right side of the curve on page 7, if you had infinite transfer capability, the forced outage rate and generation capacity available for emergencies could always get from/to anywhere you needed. That's the amount of spare generation you can call on as an insurance pool to maintain contingency reserves. How much capacity you need depends on the efficiency of delivering from one side to the other.
This is a good example of what we need to strive for. The relevant first guiding principle is making benefits available to customers. Here we're focusing on one piece of the picture: reserve margins. There are lot of other pieces we need to look at.

With regard to providing the most options in long-term planning, there is a cost. I don't think we can just focus on one plan no matter what the cost just because it provides the most options.
We agree that there is a cost/benefit tradeoff.

How does Midwest ISO prioritize transmission studies?
There is no exact answer; all are important and resources are allocated appropriately, relative prioritization may be variable by timing and requirements.

Participants discussed the idea of modifying the list of studies to combine the futures and JCSP work; Midwest ISO will work on identifying a new name for what is currently referred to as the long-term economic plan.

Is this a combination of planning staff, software and operating staff, or just planning?
(see chart on next page)
Transmission Asset Management Department staff.

Midwest ISO has approximately 500 employees. What percentage of total employees would this be?
Approximately 80 employees or Approximately 11 percent. (Note: Midwest ISO has more than 500 employees)
The OMS has recommended that the Midwest ISO increase transmission staff resources. Where are those reflected?
Mostly in the long-term planning, targeted studies and other categories.

On page 12 (Conditions Precedent to Increased Transmission Build), participants discussed opinions with assumptions around wind and RPS mandates. Specifically, opinions were given on actual vs. assumed mandates used in models. Most felt that the assumption used by Midwest ISO was valid: consensus around regional energy policy

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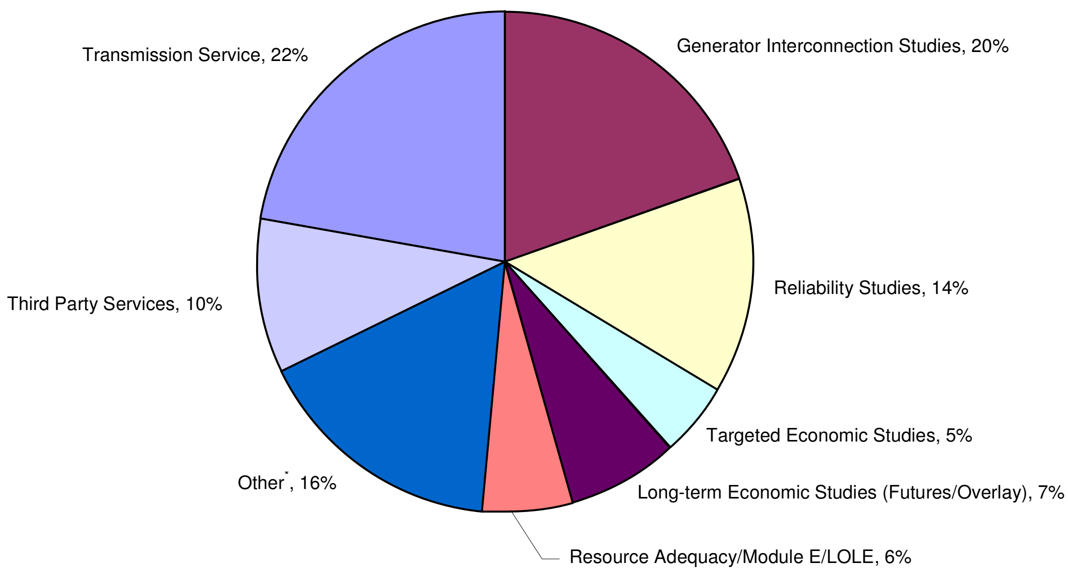
does not exist today around wind, for example, across the Midwest ISO footprint. Stakeholders discussed MTEP and RECB cost sharing criteria/thresholds.

Allocation of Transmission Asset Management Resources



* Other includes Seasonal Assessment, Regulatory Support, Seams Reliability Study, Valuation Measures, etc.

Clair Moeller commented that as we've talked about the risk of reinvigorating RPS mandates, there are estimates of around 15000 MW of existing RPS that utilities need to meet – or show cause why they can't. If we build transmission to accommodate that, it is likely that they will trip the RECB cost sharing criteria, however those projects would be shared around a reliability driven algorithm: LODF. The probability that our existing RECB allocation fairly allocates costs is a mismatch we're worried about. What we don't want is a cost allocation mechanism to cause people to leave the Midwest ISO because of a perception that the cost sharing is unfair. Cost sharing with no neighbors is no fun. *It would be useful to provide details and an example at the Advisory Committee meeting next week. We would also like to see a robust business case that although the benefits need to be identified, another point is that the impacts need to be clearly defined and evaluated.*

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Chair Voeck stated that the PAC has been invited to make a presentation at the March 12 Advisory Committee meeting. She and Beth Soholt felt it was important to talk about plans the PAC has for 2008. Participants felt that the charter and Workplan would be a good starting point for the discussion. A comment was also made that discussion of the reporting structure issue would be valid in this forum. Another comment was made that the presentation should focus on sharing information around work being done, not debate.

Participants discussed the idea of having OMS weigh in on policies/principles giving guidance as to what regulators might be looking for, though it may be an item for a different forum than the AC meeting. The suggestion was made that rather than asking them to lay out concepts ahead of talking about specific plans, we ask for their comment on specific options once plans are unfolding. Another stakeholder suggested that examples be provided for clarity.

A stakeholder commented on the issue of role clarity in terms of regulators being judges, and the larger issue of who does plans/studies, and how they get sorted out in MTEP, and suggested that the issue be included in the AC presentation as something we're still working on.

Don Neumeyer agreed to discuss guiding principles for transmission planning with OMS.

Summary of discussion by Chair Voeck:

The view of the stakeholders is that the work performed for the Long Term Plans, the Futures Based Overlay is very closely related to the work Midwest ISO is doing for the Joint Common System Plan (JCSP). The stakeholders have requested that Midwest ISO look into how these two activities can be more closely linked or combined for communication of Midwest ISO's planning activities.

The stakeholders also asked that Midwest ISO revise how it currently presents information in the long term plans or futures based overlays. Currently the future overlays are communicated as transmission plans with transmission facilities and projects, which to some appears to be a commitment that there would be efforts put in place to build the specific facilities identified in the futures. The PAC would like the future overlays to be presented as long term studies and not portrayed as transmission plans.

Action Items:

- Midwest ISO to combine Joint Coordinated System Plan and Long-Term Economic Plan into a single item, with two sub-bullets, on the list

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- Midwest ISO to consider alternate names for what are currently called Long Term Plans (stakeholder suggestions included exploratory or study)
- PAC members to consider sector viewpoints on list of planning activities and relative prioritization to April Planning Advisory Committee meeting

Input from PAC to MISO Planning Staff
Chair Voeck commented that the Midwest ISO was asked to include in materials the presentation given previously on planning activities for 2008. A summary of activities was overviewed. She asked if, as stakeholders, we are comfortable with the direction these plans are going, or they need refocusing.

Transmission Planning Activity for 2008
1. 2013/2018 (5-10 Year) NERC Reliability Assessment
2. Continue Work on Long-term Plans – Futures Based Overlay
3. Joint Coordinated System Plan (MISO/PJM/TVA/SPP)
4. Targeted Studies
   - Narrowly Constrained Areas
   - Regional Generation Outlet
   - ITC 765 kV
   - Southwestern Indiana Economic Transmission
   - Others (CAPX, Eastern IOWA Congestion, etc.)

5. Valuation Measures Development

A stakeholder made the following comment regarding the Indiana study:
It is meant to fix an existing constraint problem in that region, to minimize losses. It might become more exaggerated in the future and is a good place for low cost generation. It is being looked at in parallel with the 765 kV solution. One issue from the generation perspective is timing with implementation. From the local perspective, the wires can't get in the sky fast enough. To keep studying forever seems like we're never going to get it done.

Midwest ISO discussed the timeline for this study. If the TO wants to build transmission now, they may proceed but it may not meet criteria for cost sharing. The study is focusing now on identifying regional benefits. There's more value to a project beyond the lights not going out and better LMPs. We believe there are a few things missing in that, as do some of our stakeholders. One of the features of a study like this is that you may not show a great economic need in Indiana, but if you combine it with other projects on the board, it may become a more desirable project from a business case standpoint; we want to evaluate the possibility.

A stakeholder asked about regional generation outlet, which is a new name for what was formerly regionally planned generation interconnection projects, a study to identify what

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the projects are, how you subscribe to them, cost sharing, etc. Regional generation outlet could produce projects which become regionally planned generation interconnection projects under that methodology; it's not predetermined, but that's the expectation.
Has a geographic area been designated?
Not necessarily, but we think we're starting with the western part of the footprint.

Jeff Webb discussed the NCA study. There are 3 currently in the footprint. We have indicated our belief that upgrades we are otherwise doing in MTEP, mainly for reliability, will address 2 of them. We don't see projects fixing the other one and expect that they will continue to be NCAs going forward. We want to target in particular that area to identify first what upgrades might relieve those flowgates. Through further analysis, we will look at benefits of doing those upgrades, which probably will mean doing a RECB II pass on it. There likely is some economic congestion that RECB metrics might address. If that isn't the case, we might be able to make some claims about who we perceive to be the beneficiaries. We can't do a study on how to move forward with those upgrades until we see what would be required under the tariff. We may identify upgrades that would resolve them and may not have a mechanism to move them forward; there may not be a case. Another thought we had is that for the other constraints, the question has been raised that if you have a reliability upgrade that fixes a constraint as part of the NCA, maybe that upgrade isn't big enough to resolve the constraint. To thoroughly flesh out we'd have to do PROMOD analysis around the NCA including reliability upgrades and see if they were cleared by the upgrades.

The study is being pursued because The Board asked repeatedly why we had market limited conditions; we thought it was our obligation to look at since it's a constrained part of the market. The scope is in the process of being drafted.

The TDU/Muni/Coop Representative Patrick Gerum commented that with financing methods, there can be voluntary sponsorship for those projects that don't qualify for cost sharing under RECB. The amount of discussion we had around targeted studies is reflective of the interest customers have in some of these issues, and reflective of priority. Many customers can't wait 20 years for something to happen and need short-term and mid-term plans to help address some of these issues. Addressing feedback for the 2008 Transmission Planning Activities, From the TDU perspective, addressing regional generation outlet issues is a priority. The NERC reliability assessment is" bread and butter" work. O the 5 Activities the "Futures" related work represents 2 out of the 5 activities (#2 and 3) and there are only 5% of the MISO resources allocated to those particular efforts. A major issue the TDU sector has with the characterization of "Futures" studies is that they are identified as "plans". We (TDU sector) would say it's not a plan, but an exploratory study. We see that the "Futures" analysis would have some benefit, and aren't saying they shouldn't be done. It's important to have a feedback mechanism for policies that have been put into place without the benefit of the information that these

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studies could provide. We would like to increase the priority of some of the targeted studies and allocate more resources to better develop the process if possible. With regard to the objectives of the "Futures" studies and delivery of 20% to the Eastern Interconnect, does the Midwest ISO have an obligation to build to meet this scenario? With 20% RPS mandates, there are a lot of issues with operations, feasibility, saturation and pricing impacts that still need to be addressed.

Dale Osborn clarified that the Joint Coordinated System Plan (JCSP) has 3 sections:
1) DOE is paying for the development of a time synchronized wind model using a consistent set of assumptions which covers 90% of the potential land based wind generation in the U. S. Eastern Interconnection.
2) Midwest ISO and other participants are developing a conceptual transmission expansion that would go with a 20% energy wind generation scenario; and about a 5% wind energy wind energy scenario that is based on the present wind mandates in the U.S. Eastern Interconnection.
3) DOE is paying for the execution of a wind integration study for the JCSP study area. The Midwest ISO will participate in that study supplying information, and that study will identify what limitations are on the 20% wind energy future. It should include operator and planning inputs and is a tremendous opportunity to get these questions answered. It will not involve financial inputs from the Midwest ISO.

Are you looking for feedback on the presentation, what's being done on these studies, or just saying these are the things the Midwest ISO is doing and do we agree they're valuable things to do?
Chair Voeck said that the idea is to find out whether or not the PAC believes the planning activities the Midwest ISO set out for in 2008 cover the things we want them to look at. Do we need to make adjustments to the associated objectives? Chair Voeck would not envision that the PAC report at the Advisory Committee would go over specifics of this discussion, rather the PAC's role in providing guidance.

Stakeholders commented that the slide on 2008 studies should be shown at the AC. The suggestion was made for the participants to order the studies in order of preference, however other felt that wouldn't be possible and the level of priority could change over time. Interest was expressed in joining efforts of the futures based overlay with JCSP; however Chair Voeck said that would have to be an item for discussion at a future meeting.

Patrick Gerum identified that during the development of the "cross border" cost allocation for reliability the "futures" scenario designs were not contemplated by many of the participants. The Midwest ISO can not ignore lower costs for TOs and end users as a primary driver for project justifications. If there are proposed system improvements involving a lot of wind going east, the justification review not only needs to look at the benefits but also the negative impacts to MISO customers.

Jeff Webb discussed reliability study in the JCSP. There's a separate question around which reliability projects might find something uniquely not found in other plans – which of those should fall into cost allocation cross-border? That's probably a question we should take up again as we meet on cross-border cost-sharing, for which a filing is due in August. Once we have the mechanism understood and the BPM/tariff in place for cross-border sharing, then we would apply that cost-sharing. Now, we have a final order on how we share reliability projects; the filing in August will be with regard to economics. Anything out of the JCSP study fitting reliability or economic criteria we then would apply cross-border cost-sharing.

Looking on the website under expansion planning projects, there are folders set up for most of these projects, but not the NCAs.
The scope document is in development and information should be posted as soon as available.

Order 890 Transmission Service Impacts
Eric Laverty overviewed impacts to Long Term Transmission Service Requests as a result of Order 890, and reasoning for the change in process. There is now a specific deadline and penalty structure for impact studies completed after 60 days. Process changes will include simplifying the study scope, engaging TOs when only when necessary and making transmission customers aware of the standard and simplified scope.

A participant inquired about the idea of Midwest ISO paying TOs to do studies, and Eric said that concept is still being considered. If a TO was going to perform a study, we have always contracted and paid them. What hasn't been paid for to date is the ad hoc group participation for peer review. Where that comes in is the bottom row on the Truth Table (see pg. 6 of presentation). The immediate kickback from the transmission customer is paying everybody in the footprint to review every study. What we propose here is that we know where constraints are and facilities, and engage those entities; it puts a break on the transmission customer and cuts down on having to look at every single study.

Queue Process Improvement Update/Draft Solution Review
Jennifer Curran overviewed queue evolution graphs; the Midwest ISO is seeing more and larger requests. Despite discussion on difficulties and length of time to get through the queue, the requests continue to flow in. Jennifer discussed process objectives and overviewed changes; at a high level we're addressing taking the current feasibility study and making it more useful. There are three pathways through the study process, which has less emphasis on order and an optional "fast path" (Definitive Planning) for requests meeting customer and system readiness criteria. Projects not meeting "fast path" criteria would follow a process similar to today's (System Planning & Analysis).

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Jennifer discussed the proposed deposit and suspension requirements. Deposits will be sized to actual study costs and will be collected up front rather than at multiple points in the process. In definitive planning, study costs are partially or wholly non-refundable. Studies will be allowed to go into suspension only for Force Majeure and will require a non-refundable payment at the time of suspension. 40% of all requests reach IA status, and 25% of those have gone into suspension, effecting 80% of future queued projects. Issues discussed by the IPTF were ensuring milestones that were not unduly discriminatory, and allowing flexibility for those moving through the queue in such a way that it wouldn't create uncertainty for later queued projects.

There is still a "physics" problem that will need to be addressed by the IPTF following the tariff filing of the new process. Transmission capacity on the system is limited, particularly in prime wind locations, and the cost for network upgrades is often greater than a single generator can bear. The process isn't trying to solve a wind problem, but rather queue issues. The Buffalo Ridge area was referenced where no amount of study process improvement will fix issues related to lack of generation outlet. This proposal also doesn't address cost sharing/RECB issues.

The IPTF is continuing to work on process details and group study requirements, aiming for a vote in late March/early April. The recommendation will come to the PAC for discussion and/or voting, then will be raised to the AC. Tariff language and the BPM will be circulated with a targeted filing date of April 30 or May 15.
It would be important for this group to vote endorsement of what the IPTF does. Also, this may require calling a special AC meeting given that the annual stakeholder meeting will take place in April.
Should we go forward with April filing, we've already discussed with the AC Chair the possibility of a special meeting.

Getting rid of suspensions or limiting the conditions will definitely help the process. This is probably the best we can do to shrink the process (fastlane). The real key may be getting the actual wires in the air so these things can connect and run. A key message people need to understand is that if governors are wanting more renewables and we can't get there, it's an issue. This is the best approach possible to shorten time in the queue; there needs to be understanding that until the physics piece is fixed there are still going to be major issues.
We have discussed the 3 P's to fixing: process, physics, politics/policy. All the issues with right-of-way, cost sharing and other issues need to come together to solve the problem.

After filing with FERC, do you know how long it takes for approval?
Because they're not looking at doing a rule making, it should be faster. They're indicating with a technical conference that they're focused on the issue. It should be

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months rather than years for the approval, and also depends on interventions, etc. We're hopeful that we can get a response and through the transition period yet this year.

The next meeting of the IPTF will be March 13.

Ad Hoc RECB Issues Update

Mark Kempker discussed work done by the PAC focus group. Several meetings were held since the last PAC meeting. As a reminder, this group is intending to try to address some of the MTEP issues that have come up, and other issues that seem to come up and never get a resolution. The group started off with one item to try to work through the process of how to resolve issues and do the best job resolving issues. The first one selected was Underground/Overhead (UG/OH) issue. It's simple to understand the item and we could focus more on the process for how to get to a resolution. The group may have to use a different process going forward.

The group conducted a survey on the issue, which came down to two different business models/practices that people have for UG transmission. One is characterized by a group that has plans to install and intends to pass costs to rate payers and also plans to submit costs of all UG to Midwest ISO for consideration for cost sharing under Attachment FF. The second group is different and didn't have UG or plan to install, but would bill to individual customer in their service territory the difference in price between UG/OH. Both practices are acceptable, but very different. The issue comes together when you bring cost allocation into the picture. Each policy should be able to stand alone and each should be able to retain their own policy.

The next meeting will be March 7, intending to summarize where we are on this issue and set future discussion items. Please email Mark or Julie for further information on participation.

Mark Kempker: mark.kempker@aes.com
Julie Voeck: jvoeck@atcllc.com

Chair Voeck suggested formalizing the group as more issues are coming to light, such as cost allocation and policies raised by the Planning Subcommittee.

PS Update

The PS spent time at the last meeting discussing RECB implementation issues originally identified as planning study focused in nature. The PS determined they were not and referred them to the ad hoc PAC focus group. Jennifer will communicate to Jeff Webb and Ruth Kloecker that the PAC needs to review the PS charter/Workplan for review in May.

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LTTRPWG Update
The working group met twice and has completed its work. Changes identified are necessary on the market side, not in planning.

A participant suggested that Lin Franks come back to the PAC to discuss in further detail.

Addressing Order 890 – SPMs
Jim Musial discussed concerns predicated by the clock ticking on when the next Subregional Planning Meeting (SPM) is going to be held; in the BPM it indicates certain activities are going to take place in the near future. It's supposed to be a meaningful dialogue after reviewing projects presented in January meeting. The tariff only requires 2 SPMs, and the next one may be next bite at apple. Without sufficient information we won't be able to participate in meeting fully

- If we desire additional information on projects presented at the meeting; is Midwest ISO the appropriate body to whom we would request?
- If that information is going to take time in being issued, will there be adjustments made to SPM meeting schedule to allow for review for the projects once the information has been made available?

Are you going to be working with the Midwest ISO to resolve issues or is there something the PAC needs to address?
Jim indicated that he did clarify that the Midwest ISO would be the appropriate entity; some TOs have turned over local planning process into regional. Jeff Webb indicated that we should feel free to work with the local TO in that regard as well. We also recognized that this is the first time going through the process. Early on the TOs were asked mid-December to provide information on upcoming projects so they could be posted for January; this didn't give anyone much time to put together information. He indicated that Midwest ISO staff will be posting additional information in the next 10 dyas or so. We will continue to work with Jeff and Midwest ISO on our issues.

Formation of environmental group
Dale Osborn discussed the concept of getting people together to work on environmental and right-of-way issues. Pamela Rasmussen (Xcel) offered to be the initial chair; she should be contacted by anyone wishing to participate. She will be working on the scope formed at presented at the next meeting with more detail.

The meeting adjourned at 3:32 pm.

2008 Meeting Schedule (all times are Eastern prevailing)
Lunch will be available at 11:00 am with a meeting start time of NOON.

Date	Day	Location	Time
April 2	Wednesday	LCC-B	11:00 to 3:30

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May 7	Wednesday	LCC-2, 3	11:00 to 3:30
June 4	Wednesday	LCC-A	11:00 to 3:30
July 9	Wednesday	LCC-A	11:00 to 3:30
August 6	Wednesday	LCC-A	11:00 to 3:30
September 3	Wednesday	LCC-A	11:00 to 3:30
October 8	Wednesday	LCC-A	11:00 to 3:30
November 6	Thursday	LCC-A	11:00 to 3:30
December 3	Wednesday	LCC-A	11:00 to 3:30

Planning Advisory Committee
Carmel, IN
September 28, 2011
10:00 am to 4:00 pm ET
Dial-in and WebEx information available at www.misoenergy.org

Minutes

1. **Administrative Items (B. McKee)**
   a. **Welcome and Roll Call**
   Meeting called to order at 10:00 am ET.

   Attendees:
   Chair: Bob McKee
   Vice Chair: Julie Voeck
   MISO Liaison: Jeff Webb
   Stakeholder Relations: Amanda Brower

   Coordinating: Not Present
   End Users: Not Present
   Environmental: S. Brady
   IPP: J. Voeck
   Muni/Coop/TDU: N. Balu
   Power Marketers: M. Shields
   Public Consumer: Not Present
   State Regulatory: A. McKinnie
   Transmission Owners: D. Kramer/D. Kline

   A. Collier (ACES)
   A. Jayam Prabhakar (MISO)
   a. Jensen (MidAmerican)
   A. McKinnie (PSC-MO)
   A. Ranaweera (MISO)
   B. Donovan (NIPSCO)
   B. Greene (Duke)
   B. Ho (NRDC)
   B. Kruse (Calpine)
   B. Malcolm (MISO)
   B. Mukanik (Manitoba Hydro)
   B. Smith (OMS)
   B. Stearney (MN PUC)
   B. Tallman (LGE-KU)
   C. Hagman (ATC)
   C. Hammarlund (MN Power)
   C. Keilen (PSC-MI)
   C. Long (Entergy)
   C. Marshall (ITC)
   C. Miller (FERC)
   C. Wetterlin (Xcel)
   D. Boeshaar (We Energies)
   D. Duebner (MISO)
   D. Hastings (Consultant)
   D. Janicki (Edison Mission)
   D. Jenner (Duke)
   D. Johnston (IURC)
   D. Kramer (Ameren)
   D. Lopez (MISO)
   D. Neumeyer (PSC-WI)
   D. Sapper (CES)
   D. Van Beek (MISO)
   E. Kirschner (Duke)
   G. Dawe (Duke)
   G. Jenkins (CES)
   G. Skarbakka (Iberdrola)
   G. Weiss (Ameren)
   H. Schwab (ITC)
   J. Alholinna (GRE)
   J. Bakke (MISO)
   J. Beattie (Consumers)
   J. Borrell (Consultant)
   J. Doll (Otter Tail)
   J. Doner (MISO)
   J. Flucke (KCPL)
   J. Henry (We Energies)
   J. Lawhorn (MISO)
   J. Maddock (MDU)
   J. Moore (ELPC)
   J. Moser (MISO)
   J. Musial (Detroit Edison)
   J. Myrom (MidAmerican)
   J. Nelson (Xcel)
   J. Payne (Entergy)
   J. Schmidt (Ventyx)
   J. Smith (MISO)
   J. Strong (FERC)

J. Swanson (MidAmerican)
J. Thomasen (MGE)
J. Thompson (Otter Tail)
J. Urban (PSC-WI)
J. Van Deusen (PSC-MI)
J. Weiers (OTP)
J. Yates (Eco Energy)
J. Young (Dairyland)
K. Barczak (DTE)
K. Bilas (MISO)
K. Feliks (AEP)
K. Henderson (MN Power)
K. Kohlrus (CWLP)
K. Loehr
K. Maini (MIC)
K. Nekola (Clean Wisconsin)
K. Pike (Duke)
K. Shipp (Ameren)
K. Vongkhamchanh (Entergy)
L. Franks (IPL)
L. Frisk-Thompson (CMMPA)
L. Hecker (MISO)
L. Rauch (MISO)
M. Berlinski (Beacon)
M. Dykstra (MPPA)
M. Groszek (NIPSCO)
M. Heraeus (MISO)
M. Myhre (Alliant)
M. Rahman (ETA)
M. Satyanaryan (Enxco)
M. Seymour (Iberdrola)
M. Shaw (Exelon)
M. Shields (DTE0
M. Steckelberg (GRE)
M. Tackett (MISO)
M. Vrbas (PS Analytics)
M. Wisersky (MGE)
R. Konidena (MISO)
R. Lamnick
R. McCausland (Ameren)
R. Mork (IN OUCC)
R. Pulkrabek (MISO)
R. Rismiller (ICC)
R. Snyer (IN OUCC)
R. Walter (Alliant)
R. Westphal (MISO)
S. Ahman (FERC)
S. Bayer (NIPSCO)
S. Burgdorf (Consumers)
S. Change (MISO)
S. Deffenderfer (Ameren)
S. Hansen (MN PUC)
S. Komperda
S. Leovy (WPPI)
S. Neu (ATC)
S. Offenhauser (Enxco)
S. Porter (DPC)
S. Rose (CWLP)
S. Whiton (PSC MI)
S. Wills (Ameren)
T. Elliot (IURC)
T. Jankowski (We Energies)
T. King (Wolverine)
T. Vitez (ITC)
W. VanderLaan (ICC)
W. Yeager (Duke)
Y. Gu (MISO)
Z. Magos (FERC)
Z. Zhou (MISO)

b. **Review / Approve Agenda**√
Several revisions were made to accommodate presenter schedules. The agenda was approved.

c. **Approval of August 24th Meeting Minutes**√
Minutes approved as posted.

d. **Call for Leadership Nominations**
The nomination period for PAC chair and vice chair is open through through October 12, 2011. Additional nominations will be taken from the floor at the October PAC meeting and if either election is contested a vote will be conducted through an e-mail ballot. The term of service will be November 2011 – December 2012.

e. **Review of 2012 Schedule**
Stakeholders were asked to review the schedule and provide any comments by next month's meeting.

2. **Top Congested Flowgate Study Update (Z. Zhou)**
Zheng provided an update on this study as posted with meeting materials. An appendix is available for those seeking further detail. The next meeting for the Technical Review Group (TRG) for the study is October 12. MISO was asked about the consistency with which flowgates were determined for inclusion in the study relative to in-service dates of MVPs. Jeff Webb indicated that this is something that would continue to be revisited as the MVPs progressed. Some concern was also expressed about projects moving from one appendix to

another in MTEP based on proposed eligibility criteria for RECB II Market Efficiency Projects; Jeff indicated that none of these projects are targeted for MTEP11 and would only be approved based on whatever is in the current tariff.

3. **Cross States Air Pollution Rule (J. Smith / R. Westphal)**
   An EPA Rule Impact Rule Workshop has been scheduled for October 13. Many of the questions and discussion from the PAC meeting was referred to this workshop to be addressed. Registration and additional information may be accessed at: https://www.misoenergy.org/Events/Pages/EPA20111013.aspx . Stakeholders were invited to provide questions that they would like MISO to address in the workshop.

   Ryan was asked about the calculation used on slide 5 of the presentation, which used public information available on the EPA website. The intent of the calculation is to indicate that we should see less production from coal units based on proposed changes. Information related to retirements has been shared with affected unit owners, but will not be made widely available to stakeholders at less than a fleet-level basis.

   The draft report is being finalized as comments are being responded to. There will be minimal substantive changes to the report and publication is targeted by no later than the end of October. The data in the report is not changing. MISO was asked to continue performing EPA rule studies as the rules are finalized.

4. **Module E Capacity Tracking Tool Overview (C. Clark)**

- This was a follow up discussion from the last meeting. Carmen provided an overview of the MECT Tool that is targeted for use starting in the MTEP13 planning cycle to track demand growth rates, energy growth rates, and projected DSM for use for MTEP economic study assumptions. EE registration will be part of the RAR construct proposal, which will be considered after an order is received from FERC on MISO's proposal. In the next PAC meeting there will be a discussion about what changes are needed to the MECT Tool for caputuring the information needed for the MTEP assumptions.

5. **MTEP Substantive Feedback Review√ (L. Rauch / R. Pulkrabek)**
   Laura thanked stakeholders for input provided on the MTEP11 report and provided an overview of the major areas where comments were received and MISO responses. The full document of comments and responses is provided with meeting materials.

   The following motion was moved by Dan Kline, Shawn Brady. Motion passed with four in favor, 2 abstentions.

   Advice to the Advisory Committee on input for MTEP 11:

   The Planning Advisory Committee (PAC) sectors have reviewed and discussed the draft MTEP 11 Report that MISO will send to the Advisory Committee (AC) and MISO Board of Directors for approval in December. The PAC sectors have provided written comments and suggestions for improvement of MISO's planning activities to be included in future planning processes. PAC sector members are willing to present their comments at a future AC or Board meeting and to answer any questions that the AC or Board may have regarding the comments and recommendations. Although various points for improvement have been raised, the PAC believes that the MTEP 11 report should proceed to the Board of Directors for approval.

6. **Energy Storage Study Update (D. Van Beek)**

Dave provided an overview of EGEAS for modeling in the Energy Storage Study. Three long-term storage types were identified for analysis: pumped storage hydro (PSH), compressed air storage (CAES) and battery. CAES was discussed in this presentation. PSH and battery were used similarly in the model and not picked in the model so he only looked at CAES at this time. Dave discussed key sensitivities and Phase I EGEAS findings. Work now will shift more to PLEXOS modeling. The next study meeting will be October 4.

7. **Demand and Energy Growth Rate Assumptions (R. Konidena)**
Rao provided a summary of the proposed approach for MTEP12 as posted with meeting materials. Participants discussed demand/energy growth rate assumptions with adjusted growth rates from MTEP11. The proposed values were adjusted based on feedback from stakeholders and are still open to further adjustments.

JT and Bob discussed a targeted meeting with SPP to develop a joint scenario that would have similar assumptions. Stakeholders were in favor of having this meeting and suggested a mutual meeting location on December 1, with the November 30 PAC meeting moved as well. MISO will work with SPP to see what space is available and a notice will be sent to stakeholders.

At the October PAC meeting the group will continue to discuss the method for developing demand and energy growth rates and the futures that will be used for MTEP 12. It is anticipated that the PAC will select the futures and identify demand and energy growth rate assumptions for MTEP 12 on November 30 and then to start EGEAS forecasting runs November 30 – March 2012.

8. **Wind Planning Analysis Task Team Recommendations (D. Duebner)**
This group met as a subgroup of the PSC at the directive of the PAC. David reviewed the deliverables from the group and a summary of findings. When doing reliability planning MISO is looking for stressed conditions. Two motions were presented to the PSC and both were supported. MISO recommended that the PAC support the ATC motion to include a 0% wind Light Load model in planning studies. The PAC agreed that the WPATT and PSC had reviewed this issue thoroughly and should move forward with the recommended approach.

9. **RECB1 Cost Allocation Methodology for Complex Projects (D. Duebner)**
David provided an overview of RECB1 subregional allocation methodology, existing methodology for complex projects, and proposed methodology for complex projects. MISO recommended that the Transmission Planning BPM be updated to reflect that this methodology be used for subregional allocation LODF calculation of complex projects. This methodology would be used any time an LODF allocation is appropriate for the project being evaluated and where the usual method of allowing the MUST application to product the distribution factor does not work. It will not be used for Generation Interconnection Projects. The PAC agreed that this should move forward, and MISO was asked to notify the PSC that the methodology is being applied so it could be reviewed.

10. **Order 1000 Discussion (J. Moser)**
FERC staff was on hand to address questions relating to the order. Jesse reviewed the proposed plan for working through Order 1000 issues with stakeholders through the MISO stakeholder process and with other RTOs. Two compliance filings are required: October 11, 2012 (regional) and April 11, 2013 (interregional). MISO proposed that the PAC would undertake regional planning items and that the RECBTF would undertake regional cost allocation items. Stakeholder workshops will be scheduled for interregional planning, cost allocation purposes, and the elimination of federal right of first refusal. This will be discussed

with the PAC again on October 25 and the RECBTF on October 27. Coordination workshops are TBD; MISO hopes to have dates to share at the October meeting.

11. Committee Updates

a. Interconnection Process Task Force (R. Oye)
No update given.

b. LOLE Working Group (J. Beattie)
Last meeting: September 7
MISO reviewed preliminary results for LOLE analysis, discussed PRM vs. resources in external zones and PRM vs. external tie limits. A conference call was added for October 5 and the next regular meeting was moved to October 14 with a goal to provide a report to the PAC before the November 1 deadline.

12. New Business
Bob introduced an action item from the Steering Committee to discuss any possible changes to the stakeholder committee structure that may be needed to accommodate the integration of Entergy. He indicated that this would be a discussion item next month.

13. Adjourn
Meeting adjourned at 3:30 pm ET.

Next Meeting: October 26, 2011

RECB Task Force
Carmel, IN
May 27, 2009 9:00 to 4:00 ET
MINUTES

Meeting called to order at 9 am ET.

1) Standing Items **Azar** **9:00**
a. Roll Call

Attendees in the Room:

Chair Comm. Lauren Azar, PSC WI
Midwest ISO Liaison, Jennifer Curran
Jennifer Ayers-Brasher, E.On Clim. & Renew.
Chancy Bittner, IUB
Nicholas Bowden, IL Commerce Comm.
Al Freeman, PSC MI
Anna Giovinetto, RES Americas
Linda Horn, Wisconsin Electric
Dennis Kramer, Ameren
Gary Mathis, MGE
Darcy Neigum, Montana-Dakota Utilities Co.
Tanya Paslawski, ITC Holdings
Chris Plante, WPSC
Wendy Reed, Wright & Talisman
Richard Seide for RES Americas
JoAnn Thompson, Otter Tail Power Co.
Bill Smith, OMS
Gary Fuerst, FirstEnergy
Kevin Largura, NIPSCO
Jeremiah Doner, Midwest ISO
David Sapper, CES
Matt Tackett, Midwest ISO
Patrick Clarey, FERC
Vice Chair Paul Jett, Duke Energy
Amanda Brower, Midwest ISO
Stewart Bayer, NIPSCO
Marty Blake, Hoosier Energy/SIPC
Lin Franks, IPL
Steven Gaarde, Consumers Energy
Mike Gregerson, Midwest Governors Assoc.
David Johnston, IURC
Matt Lacey, GRE
Natalie McIntire, Wind on the Wires
David Nick, DTE
Randel Pilo, PSC WI
Laura Rauch, Midwest ISO
Bryan Rushing, LS Power
Mike Taylor, ITC
Marya White, MN Office of Energy Security
Purvi Patel, ITC
Chris Kopel, Iberdrola
Joyce Davidson, Midwest ISO
Jeff Webb, Midwest ISO
Wanda Jones, PSC MI
Chris Miller, FERC
Gail Maly, WI PSC

Attendees on the Phone:

Tanya Peters, Clipper Wind
Brian Dekiep, MT PSC
Betsey Rubio, Clipper Wind
Blaine Erhardt, BEPC
Brian Giggee, MDU
Cathy Brewster, Midwest ISO
Chris Constantine, FirstEnergy
Dennis Kramer, Ameren
Dave Newberry, MidAmerican
Don Neumeyer, PSC WI
John Dwyer, IA OCA
Greg Gudeman, Ameren
Jason Cross, OH PUC
Jeremy Hagemeyer, MO PSC
Joanne Borrell, FirstEnergy
Angela Maiko, GRE
Beth Soholt, Wind on the Wires
Bill Greene, Duke
Bob Burner, Duke
Brian Zavesky, MR Energy
Chad Geiger, Wolverine
Cindy Hammarlund, MN Power
Daniel Kline, Xcel
David Duebner, Midwest ISO
Eric Williams, Midwest ISO
Gary Husky, Vectren
Ian Benson, Xcel
Jeremy Fischer, MDU
Jerry Lein, ND PSC

John Kayser, Alliant Energy
Julie Voeck, NextEra Energy
Keven Szarkowski, BEPC
Kwafo Adarkwa, ITC
Luis Leon, Otter Tail
Mal Bertsch, ATC
Megan Wisersky, MGE
Michael Erbrick, EMELP
Mike Steckelberg, GRE
Ming Ni, Midwest ISO
Rhonda Peters, Clipper Wind
Rudy Rivas, Clipper Wind
Steve Offenhauser, enXco
Terri Eaton, Xcel
Tom Mielnik, MidAmerican
Joseph Stephanoff, ITC
Kara Henderson, MN Power
Kevin Shipp, Ameren
Lee Barrett, Duke Energy
William VanderLaan, ICC
Mary Ann Groszek, NIPSCO
Melissa Seymour, Iberdrola
Mike Donahue, MN Power
Tom Whitaker, Infinity Wind
Ray Cuadra, NIPSCO
Robert Walter, Alliant
Steve Leovy, WPPI
Steve Rose, CWLP
Todd Butkowski
Tony Yonnone, Horizon Wind

b. Review of Agenda

No changes to the agenda.

c. Approval of Meeting Minutes: May 12, 2009 √

Two names were corrected. Kevin Largura moved to approve minutes; Lin Franks seconded. Minutes were approved by voice vote.

2) Review of Midwest ISO Proposal

Jennifer Curran reviewed a portion of the group study 5 projects impacted under current RECB I GIP methodology. Midwest ISO has not done a consumer rate analysis. Most of the group 5 projects tend to be towards the Iowa state line; all IAs executed are subject to the cost allocation in place at the time they are signed.

Jennifer discussed the RECB Phase I recommendation and rationale, cost causer approach. Upgrades at 345 kV and above will be allocated 90% to Interconnecting generators and 10% postage stamp to Midwest ISO. Network upgrades below 345 kV will be allocated 100% to interconnecting generators. These allocations are not contingent upon the interconnecting generator being a network resource or executing at least a one-year power purchase agreement (PPA) to serve Midwest ISO load.

Straw poll votes in the last meeting seemed to reflect the majority of sector positions, indicating what the response would be from the Advisory Committee. Jennifer verified that those voting in straw polls did not vote in duplicate; detailed results will not be published. One comment received is that the free-rider or late-comer issue is an increasing concern as we look to put costs on the generator. This is not within the scope of what was defined in the charter for Phase I and stakeholders were asked for any ideas to resolve or if it could be included in Phase I.

90-95% of the network upgrades currently in the queue have a least one shared upgrade. Cost sharing for shared upgrades in group studies (Multi-Party Facilities Construction Agreement-MPFCA) is being dealt with by the IPTF. Their next meeting is Friday, May 29.

Discussion: Rate recovery for generator funded upgrades where TOs will remain the owner and operator of the transmission lines.

Concern was expressed that a temporary fix could inadvertently have more longevity than expected if Phase II gets drawn out. Midwest ISO will not file a request with a sunset date and intends to continue diligently with Phase II work. ATC and ITC will need to determine what they would like to do with the attachment in respect to their own tariffs.

In the last meeting, the idea was discussed for Otter Tail to address their issues with allocation independently; they were amenable to that given assurances from other stakeholders that they wouldn't be challenged at

FERC. They did not receive those assurances, leading the RECBTF to a more broad-based discussion. Also discussed was the idea of a circuit breaker approach, which was determined not to be feasible in the tight timeframe. Concern was expressed by a stakeholder that in relieving the “Otter Tail” problem it creates a benefit to every other TO unrelated to those interconnection requests. Other stakeholders commented that limiting a fix strictly to one entity would cause discrimination issues.

Discussion: free-rider and first-mover issues. Midwest ISO has not discussed how grouping would occur in terms of which generators are co-funding a network upgrade; it would have to be defined under Attachment X and the MPFCA.

WOW: This proposal meets the needs of transmission providers and doesn’t address needs of generators to enter the market and is discriminatory. The proposal is not balanced and doesn’t recognize full benefits. What is the commitment from TOs to come back and work on this with us in Phase II? We will not support this proposal in a RECBTF vote or at FERC.
Iberdrola: The proposal to put funding on generators is going to have a chilling affect on the wind industry, who may not be able to financially absorb the hit to be delivered with these projects. We too will fight this at FERC.
Comm. Azar: My personal commitment is to continue to drive forward with Phase II. We have a commitment to get Phase I done and to solve the short-term problem, then move quickly in to Phase II. We will not sit back and just wait for things to happen. We have asked in Phase II that participants provide information on what they consider to be the barriers to entry. This is also mirrored in work done by the OMS CARP group, UMTDI and RGOS. A pending congressional conference could affect how we move forward in Phase II as well.

DTE: It’s a fallacy to suggest generators or TOs are paying for this when ultimately it’s end use customers. Loads are benefiting from these upgrades so LSEs not benefiting shouldn’t pay. This debate has been characterized as generators vs TOs. DTE is an LSE serving load in southeast MI; we have an RPS requirement for the state of MI that has to be served by wind within MI. We’re going to be paying for upgrades and transmission to bring it to our customers.

SIPC/HE: We agree with DTE: the purpose is to get costs to those who are really benefiting. This is a targeting mechanism; the other way was to go straight to the PPA which wasn’t supported.

GRE: The generic nature of this isn’t just to Otter Tail but will affect all the small utilities in western Midwest ISO who are bearing the brunt of upgrades.

Comm. Azar: Would the wind industry be more supportive of this proposal if there was a sunset provision?
WOW: That could work if there was a robust free-rider or late-comer approach to go along with it that could address the fact that for a time parties would be faced with an allocation that could change.
Iberdrola: We would be willing to accept something like this to solve the Otter Tail problem, but you have converted to the entire footprint. This is a fundamental change in assumptions and in some cases whether or not we have a viable project anymore. The issue of a sunset date doesn’t necessarily solve issues for us.

RES: The largest wind developer in the world is telling you that financially they’re going to struggle. Have you looked at how community development entities will move forward? My sense is you’re going to break projects. There is a policy issue with who’s going to be hit the hardest. At least in the queue reform process we broke it down to categories of MW.
J Curran: We discussed that issue as well and are cognizant that this is an issue. There are many policy issues being balanced here. Ultimately, for better or worse, it puts the question back to states of policy and funding.

Comm. Azar’s recommendation was to consider the following requests made by wind developers, given that failure at FERC is not an option:

1) Circuit breaker methodology by which we do a surgical strike in Phase I, finding the group of individuals affected by the problem in the tariff and implement a fix only to those individuals based on a set of criteria. (IPL was asked to give their presentation from the last meeting.) One of the problems was a set of criteria we could use to define.

2) A sunset provision; Phase II is set to end in December, which is unlikely. CARP is supposed to finish by fall, perhaps the end of the year. That will likely help to shape Phase II efforts. The purpose is to make sure we finish Phase II, not go back to pre-phase I.
3) Allocation; revisit the split of 100% to generators for over 345 kV and 90% to generators for 345 kV and below.

Sunset Discussion
Comm. Azar gave notice that this proposal would roll into a straw poll at the close of the discussion. The wind industry would like to see all three items listed above included in the proposal. Participants discussed.

MN OES: I am concerned about putting a date into the application to FERC; another option is to propose a provision requested that if by a certain date FERC doesn't feel that this group is making sufficient progress on Phase II, at that point they entertain proposals for a sunset date. This would still give us the push we're all going to need to finish Phase II without having a drop-dead date.
Comm. Azar: This would be progress reports to FERC where they at any point could say we're no making enough progress.
WOW: We could support the option of making a filing to FERC that if you're close to a solution to file for an extension.
MN OES: Usually when there's a date to a filing people wait until that date to finish. There are problems with a short or long timeframe. What date do you and other wind developers feel you could live with?
WOW: The date is really about what we think is required in the process for Phase II. We would be hard pressed to meet the Phase II goal by the end of the year. We don't have a change proposal to discuss and can't make any strong commitment today.

DTE: This could create another unintended consequence: how many generators are going to sign IAs knowing there's going to be potentially a better solution?
Iberdrola: Under the new queue process your ability to suspend is gone. We have milestones and decision points to meet.

MGE: With regards to a hard date are we talking about a filing date or effective date?
Comm. Azar: Filing date. This would be a hard deadline and the effective date would correspond with our filing date. We could say to FERC that if we don't file Phase II by [to be determined] date we're reverting back to pre-Phase I. A progress report would be drafted by Comm. Azar, not Midwest ISO.
J Curran: Keep in mind that the Midwest ISO can file a solution regardless of votes taken today.

A straw poll was set up to evaluate member participant interest in a sunset date or progress reports with a more soft ending.

Should there be a hard sunset provision for Phase I or a progress report on Phase II efforts?
a) hard sunset b) progress report c) none of the above d) abstain e) someone else is voting for me f) not eligible to vote

Comm. Azar: Option b) progress report was the prevailing response. We will have quarterly progress reports as the recommendation.

Mark Kemper discussed the IPL presentation on the circuit breaker approach given in the last meeting.

Jennifer Curran provided an example of project costs under Load Ratio Share (LRS) using the circuit breaker approach, compared to today's allocation using LODF.

Midwest Independent Transmission System Operator, Inc.

	A	B	C	D	E	F	G	H	I	J	K
1											
2			**Load Ratio Share**	**Sample Share Today (LODF)**	**Project Cost Today (RECB 1) ($ millions)**	**Maximum Cost Under LRS**	**Difference**				
3	Zone 1		3%	35%	35	3	-32	←	Triggers Circuit Breaker		
4	Zone 2		7%	5%	5	7	2				
5	Zone 3		10%	10%	10	10	0				
6	Generator		N/A	50%	50	N/A					
7	**Total**			**100%**	**100**						
8											
9											
10	One Approach - Circuit Breaker Triggers 80/20 Cost Sharing (all voltages)										
11			**Base Cost**	**Additional Cost from Post Circuit Breaker Method**	**Total Cost**	**Cost Under RECB 1**	**Difference**				
12	Zone 1		3	1	4	35	31				
13	Zone 2		5	1	6	5	-1				
14	Zone 3		10	2	12	10	-2				
15	Generator		50	26	76	50	-26				
16	Previously Unaffected Zones			2	2	0	-2				
17	**Total**		68	32	100	100	0				
18											

Participants discussed pros and cons of the LRS allocation approach.

NIPCSO: The TOs are supportive of progress reports. The other issues we felt we already voted on. We don't believe in our discussions that the circuit breaker approach will work for Phase I as it is too complicated. We had discussion in the last meeting around PPAs and determined that it was too complicated. We believe the Midwest ISO proposal is simple and should be filed as soon as possible, then we should continue with Phase II.

Otter Tail: The TOs have historically been very opposed tgo cost sharing on interconnection projects when exported outside the Midwest ISO. We believe the proposal to remove a requirement to serve network load is a significant compromise. Nothing is off the table for Phase II. We have been planning our systems taking into account the optimum plans for integrating renewable resources. A circuit breaker doesn't send economic pricing signals.

NOTE: The TOs supporting the Midwest ISO proposal are those that supported the TOGA proposal: Ameren Services, CWLP (Springfield, IL), Duke Energy Services, LLC, GRE, Hoosier Energy, Minnesota Power, Montana-Dakota Utilities Co., NIPSCO, Northern States Power Company, Otter Tail, SIPC, Southern Indiana Gas & Electric Co., SMMPA, Wabash Valley Power Assoc., Inc.

The RECBTF determined that without general consensus we should move forward with the current proposal and move into Phase II. Midwest ISO will provide draft tariff language by June 4 to discuss at the June 9 meeting. The June 9 meeting was changed to a conference call to review the language, and an email vote will occur after the meeting. Phase II will start at the June 24 meeting.

Discussion turned to the possibility of a late-comer policy; this is an agenda item for the IPTF to look into. Natalie was asked to review the presentation she gave in the last IPTF meeting with expansion to current policy that would allow reimbursement of original funders by those who join within 5-10 years. Participant consensus was that this would be an item to look into for Phase II.

3) Related Initiatives

a. Upper Midwest Transmission Development Initiative Update, CARP Update

Randy Pilo overviewed work of the cost allocation subgroups. Last week they discussed suggestions for Commissioners to consider; some components suggested were along the lines of developing a package of materials on tariff design (2-3 proposals). There is also interest in flushing out beneficiaries further and letting stakeholders review the legal analysis. A monthly email update will be sent out. The UMTDI is expecting some RGOS results this summer and will start working on dollar numbers. There will be a large gathering of all UMTDI stakeholders at a date to be determined. They hope to have done by October. The end product is in the hands of Commissioners and Governors. Beyond the principals there was a lot of feedback on how to factor in benefits beyond these 5 states.

The next CARP meeting is May 28 at Midwest ISO. Feedback has been received from a number of stakeholders with regard to modeling assumptions. CARP will go through those and should finish specifying modeling parameters for indicative plans, then will send another request to stakeholders with variables determined and will ask for a very quick turnaround.

Eastern Interconnection Planning Cooperative Update
Comm. Azar commented on preliminary involvement of over 20 planning authorities in the eastern interconnect, looking to respond to a future DOE RFP for a large scale transmission study receiving funds allocated in the federal stimulus package. There is no clear indication at this point of which entity will handle the study for the eastern interconnect, thus RTOs, ISOs and other planning authorities in the eastern interconnect have decided to create a response to the RFP expected to come out in the next few months.

Earlier this month, Comm. Azar and the president of PJM convened a group of regulators to begin discussion about what role this cooperative should have in the planning process. Another meeting is planned for June. A call will be going out to Commissions and Governors for each of the 40 states in the eastern interconnect to discuss what the states want to do with regard to interconnect planning.

The group is also looking at how to actually do the work should they be selected, and what the legal arrangement is to do and fund the work. The proposal will be made available for stakeholder review when available. Midwest ISO is participating in these meetings.

Is the scope equivalent to the JCSP in terms of the approach looking at satisfaction of renewable requirements?
Comm. Azar: JCSP was not mandated by the law, which does speak to renewables. Ultimately it could be the return of the JCSP but I don't think it will be that necessarily. We hope states will weigh in on whether or not they want to see an RTO compilation or a true system plan. The timeframe for completion is 2013.

4) New Business
No new business was identified.

5) Action Items and Next Steps
The June 9 meeting was changed from in-person to conference call only. A room will be maintained in Carmel for those wishing to participate from Midwest ISO facilities.

Meeting adjourned at 2:52 pm ET.

RECB Task Force
Carmel, IN
October 27, 2011
9:00 am to 3:00 pm ET
Dial-in and WebEx information available at www.misoenergy.org

Minutes

1. **Administrative Items (D. Kline)**
   a. **Welcome and Roll Call**
   Meeting called to order at 9:00 am ET.

   Vice Chair: Dan Kline
   MISO Liaison: Jennifer Curran
   Stakeholder Relations: Amanda Brower

A. Iler (MISO)
A. McKinnie (PSC-MO)
B. Barrowes (Baker Botts)
B. Bokram (PSC-MI)
B. Burner (Duke)
B. Erhardt (BEPC)
B. Greene (Duke)
B. Malcolm (MISO)
B. McKee (ATC)
B. Rushing (LS Power)
B. Vanderlaan (ICC)
B. Yousufi (MidAmerican)
C. Allen (PSC-MS)
C. Bittner (IUB)
C. Devon (PSC-MI)
C. Hammarlund (MN Power)
C. Morakinyo (Wisconsin Electric)
C. Plante (WPSC)
C. Wetterlin (Xcel)
D. Chatterjee (MISO)
D. Duebner (MISO)
D. Johnston (IURC)
D. Kramer (Ameren)
D. Maxwell (Manitoba Hydro)
D. Neigum (MDU)
D. Neumeyer (PSC-WI)
D. Prowse (Manitoba Hydro)
D. Sapper (CES)
E. Pfeiffer (Quanta)
G. Fuerst (First Energy)
G. Mathis (MGE)
J. Borrell (Consultant)
J. Bourg (Entergy)
J. Doner (MISO)
J. Harrison (Baker Botts)
J. Hayem (Invenergy)
J. Henry (We Energies)
J. Maddock (MDU)
J. Moser (MISO)
J. Rasmussen (Duke)
J. Urban (PSC-WI)
J. Webb (MISO)
J. Weiers (Otter Tail)
K. Adarkwa (ITC)
K. Deshmukh (ITC)
K. Feliks (AEP)
K. Noral (PSC-MT)
K. Shipp (Ameren)
L. Franks (IPL)
L. Hall (MISO)
L. Hecker (MISO)
L. Melvin (Manitoba Hydro)
M. Blake (SIPC/HE)
M. Ellis (MISO)
M. Myhre (Alliant)
M. Ni (MISO)
M. Parsley (Vectren)
M. Satyanarayan (Enxco)
M. Shields (DTE)
M. Steckelberg (GRE)
M. Taylor (NIPSCO)
M. Volpe (Dynegy)
M. Vras (PS Analytics)
M. Wisersky (MGE)
N. Campbell (MN Dept. of Commerce)
P. Harrell (DC Energy)
R. Bo (MISO)
R. McCausland (Ameren)
R. Mork (IN OUCC)
R. Pilo (PSC-WI)
R. Rismiller (ICC)
S. Brady (WOW)
S. Burgdorf (Consumers)
S. Cavote (NIPSCO)
S. Chang (MISO)
S. Hansen (MN PUC)
S. Vanzante (alliant)
T. Mielnek (MidAmerican)
Tammy * (IURC or IN OUCC)
W. Reed (Wright & Talisman)
W. Yeager (Duke)
Y. Gu (MISO)
Z. Zhou (MISO)

b. **Review / Approve Agenda√**
Agenda approved as posted.

c. **Approval of July Meeting Minutes√**
Minutes approved as posted.

d. **Leadership Nominations**
The nomination period is open for 2012 committee leadership. Nominees should be sent to Amanda Brower by November 10. If the positions are uncontested it will be a voting item for the November meeting, or by email ballot
Paul Jett will not be running for the chair position. Dan Kline was nominated to serve as chair.

e. **Review 2012 Meeting Dates**
2012 meeting dates were approved.

2. **Order 1000 Regional Cost Allocation Compliance (J. Moser / J. Doner)**
There are two major compliance dates for Order 1000: October 11, 2012 (regional) and April 11, 2013 (interregional). The RECBTF will focus on the regional cost allocation portion of compliance. Jeremiah walked through what MISO feels are the eight regional cost allocation requirements that need to be addressed in the filing noting areas where MISO believes compliance already exists or where action is required. Some stakeholders disagreed that MISO was compliant with transparency of benefits and would like to see data provided at a greater level of granularity.

Stakeholders were asked to provide feedback by November 15. An email request will be sent to the RECBTF with links to materials and deadlines. This will continue to be discussed in the next meeting.

3. **MISO Proposal for MEPs (J. Moser / J. Doner)**
Jesse discussed the updated proposal and modified provision of increased granularity with allocation of cost responsibility. MISO was asked to confirm with the IMM his support of 100% adjusted production cost as discussed in separate meetings with OMS. Allocation in this proposal is based on distribution of benefits across the Local Resource Zones shown on slide 11 of the posted presentation. Some stakeholders expressed concern with the size and configuration of the proposed zones for allocation. These zones do not split any LBAs and were grouped based on a great deal of analysis including: past congestion analysis, natural boundaires, regulatory boundaries, etc.

MISO was previously asked to demonstrate the difference in distribution of benefits from Planning Sub-Region zones vs. Local Resource Zones. This was shown starting on slide 10 and discussed by Jeremiah. He also discussed a separate spreadsheet of preliminary results for the MTEP11 Top Congested Flowgate Study to show projects with costs > $5 million and a B/C ratio of 1.25 or greater. MISO was asked previously to look at tracking of approved vs. in-service project costs, which are provided on slides 14-16. This information can be provided with costs as well. Jennifer noted that there is work yet to be done on increasing transparency and work is underway on how to do that.

A filing date of march 2012 was recommended with the goal to have proposed MEP modifications in palce prior to June 2012 for BOD MTEP approval. If stakeholders have comments they should be sent in as soon as possible.

4. **Entergy Cost Allocation Transition Tariff (J. Curran)**

An introductory workshop was held on October 24 to begin discussing this issue. Jennifer discussed the drivers behind needing a cost allocation transition and the terms of the transition that would occur over five years. This tariff would apply to Entergy and similarly situated companies, it would not generically apply to any TO that might join MISO.

Participants discussed the calculations for MVP allocation to Entergy and requested further clarification of the examples. MISO was also asked to include information on what would be done if this test fails.

5. New Business

Jennifer discussed compliance items related to the MVP order on rehearing. One item is to take something out of the tariff, which will happen. The other is about devising the method for conducting the three year reevaluation. This will be a future discussion item for the RECBTF and has to be met in 180 days.

6. Adjourn

Meeting adjourned at 1:50 pm ET.

Next Meeting: November 29, 2011

Midwest Independent Transmission System Operator Inc.
P.O. Box 4202 Carmel, indiana 46082-4202
1125 Energy Park Drive St. Paul, Minnesota 55108
317.249.5400

Comparison of Pana connection cost to Ramey proposed Pawnee-Mt. Zion line cost

$ in millions

Ramey Pawnee-Mt. Zion line

	Cost	Cost to Ameren Illinois area custs:
Estimated cost of 345 kV line from Pawnee to staff's suggested Mt. Zion substation site assuming 46.2 mile line length:	$101.6	**$9.1**
Estimated cost of new Mt. Zion area substation and equipment:	$17.8	**$1.6**
Estimated cost of a rebuilding the Pana transmission substation at a new site and relocate existing transmission lines and equipment to the new substation due to mine subsidence:	$32.9	**$32.9**
Estimated Pawnee to Mt. Zion cost NOTE: This does not include the cost of possible system upgrades needed on the PJM and MISO transmission systems due to the Pawnee to Mt. Zion line. It also does not include the cost of actions to address the Decatur area reliability issues between 2016 and whenever the connection is implemented:	$152.3	
Estimated Pawnee to Mt. Zion cost paid by Ameren Illinois area customers:		**$43.6**

Pana connection

	Cost	Cost to Ameren Illinois area custs:
Estimated cost of Pana connection which addresses the Decatur area reliability issues in 2016 and relocates the existing Pana transmission lines and equipment to the new substation due to mine subsidence:	$202.9	**$18.3**
Estimated Pana connection cost	$202.9	
Estimated Pana connection cost paid by Ameren Illinois area customers:		**$18.3**