Exhibit No.:	
Issues:	Ameren Missouri Transmission Alternatives
Witness:	Adam C. McKinnie
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Surrebuttal Testimony
Case No.:	EO-2011-0128
Date Testimony Prepared:	February 6, 2012

MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

SURREBUTTAL TESTIMONY

OF

ADAM C. McKINNIE

AMEREN MISSOURI

CASE NO. EO-2011-0128

Jefferson City, Missouri
February 2012

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System Operator, Inc.	))))))	Case No. EO-2011-0128

AFFIDAVIT OF ADAM C. McKINNIE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Adam C. McKinnie, of lawful age, on his oath states: that he has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 17 pages of Surrebuttal Testimony to be presented in the above case, that the answers in the following Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

AL McK

Adam C. McKinnie

Subscribed and sworn to before me this 6th day of February, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer
Notary Public

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SURREBUTTAL TESTIMONY

OF

ADAM C. McKINNIE

AMEREN MISSOURI

CASE NO. ER-2011-0128

SURREBUTTAL TESTIMONY

OF

ADAM C. McKINNIE

AMEREN MISSOURI

CASE NO. ER-2011-0128

Q. Are you the same Adam C. McKinnie who filed Rebuttal, Supplemental Rebuttal, and Second Supplemental Rebuttal Testimony and Testimony in Support of Non-Unanimous Stipulation and Agreement in this docket?

A. Yes, I am.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to respond to the Supplemental Rebuttal Testimony of Office of Public Counsel (OPC) witness Ryan Kind filed on January 18, 2012.

<u>FERC Order No. 1000 and Right of First Refusal</u>

Q. Beginning on page 5 of Mr. Kind's Supplemental Rebuttal Testimony he reiterates what he calls "four new developments" that he addressed in his rebuttal testimony, and then goes on to relate how those developments are addressed in the Non-Unanimous Stipulation and Agreement. Are there any developments that Mr. Kind has failed to specifically mention or discuss?

A. Yes, Mr. Kind did not specifically mention or discuss the Federal Energy Regulatory Commission's (FERC) issuance of Order No. 1000 (FERC Order 1000). FERC Order 1000 was issued July 21, 2011. The Midwest ISO is required to make a tariff filing at FERC to bring itself into compliance regarding FERC Order 1000 for all issues other than cost allocation by October 2012, and required to make a tariff filing at FERC regarding cost allocation issues by April 2013.

Q. In short, why does FERC Order 1000 impact this case and Mr. Kind's testimony?

A. FERC Order 1000 changes how transmission builders are selected by a regional transmission organization (RTO) to build transmission projects.

FERC Order 1000, 136 FERC ¶ 61,051, Para. 225 defines "nonincumbent transmission developer" and "incumbent transmission developer/provider" as follows

> . . . For purposes of this Final Rule, "nonincumbent transmission developer" refers to two categories of transmission developer: (1) a transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, and as we explained in the Proposed Rule, an "incumbent transmission developer/provider" is an entity that develops a transmission project within its own retail distribution service territory or footprint. [Footnote omitted.]

Currently, the Midwest ISO, in essence is operating in a manner pre-FERC Order 1000. Pre-FERC Order 1000 FERC allowed RTOs such as the Midwest ISO to file tariffs and adopt governing documents that gave incumbent transmission owners the right to build transmission projects the RTO had approved in the incumbent transmission owner's region. In the Midwest ISO, this concept of a transmission owner having a right to build transmission projects includes other members of the transmission owner's holding company that are also transmission owners.

The Midwest ISO Transmission Owner's Agreement (TOA) does this in a twofold manner. First, the term "owner" is defined in the Midwest ISO TOA as:

> **P. Owner. Version: 0.0.0 Effective: 7/31/2010**
> A utility or other entity which owns, operates, or controls facilities for the transmission of electricity in interstate commerce (as determined by the

> Midwest ISO by applying the seven-factor (7-factor) test of the FERC set forth in FERC Order No. 888, 61 Fed. Reg. 21,540, 21,620 (1996), or any successor test adopted by the FERC) and which is a signatory to this Agreement. A public utility holding company system shall be treated as a single Owner for purposes of this Agreement. Each Owner shall pay the applicable membership fees and become a Member. Any termination of a utility's or entity's status as an Owner shall be determined pursuant to this Agreement.

Then, in the Appendix B Planning Framework (Version: 0:0:0 Effective: 7/31/2010) portion of the TOA, the section labeled "VI. Development of the Midwest ISO Transmission Plan," the Midwest ISO gives the "owner" and other transmission owning members of its holding company the right and obligation to build transmission interconnecting to its existing system:

> The Planning Staff shall present the Midwest ISO Plan, along with a summary of relevant alternatives that were not selected, to the Board for approval on a biennial basis, or more frequently if needed. The proposed Midwest ISO Plan shall include specific projects already approved as a result of the Midwest ISO entering into service agreements with transmission customers where such agreements provide for identification of needed transmission construction, its timetable, cost, and Owner or other parties' construction responsibilities. *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. [Italics added.]

This latter portion, giving an incumbent transmission owner the right to build projects interconnected to its existing system, is known as the Federal "right of first refusal" (RoFR). This Federal RoFR has appeared in various documents approved by FERC, including tariffs and other agreements subject to FERC jurisdiction. For example, as noted above, it is in the Midwest ISO TOA contained in the Midwest ISO Tariff at FERC as Rate Schedule 01.

FERC Order 1000 eliminates the Federal RoFR, with four caveats. This is described in Slide 17 of the FERC staff briefing outlining FERC Order 1000, Schedule ACM-1. I have attended this FERC staff briefing and other FERC staff, Midwest ISO, and Southwest Power Pool presentations on FERC Order 1000, including one FERC staff presentation to the National Association of State Utility Consumer Advocates (NASUCA). I have inserted citations to some of the relevant FERC Order 1000 paragraphs and footnotes as follows:

> Rule removes any federal right of first refusal from Commission-approved tariffs and agreements with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to four limitations [FERC ORDER 1000, Paras. 253, 313]:
>
> – This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation [FERC ORDER 1000, Para. 318]
>
> – This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring [FERC ORDER 1000, Para. 319]
>
> – This allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers [FERC ORDER 1000, Para. 321 footnote 302]
>
> – Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities [FERC ORDER 1000, Para. 253 footnote 231]

Q. At page 6 of his Supplemental Rebuttal Testimony, does Mr. Kind refer to Section 5.3 of the Service Agreement between the Midwest ISO and Ameren Services Company, as agent for Ameren Missouri?

A. Yes, at lines 8-13.

Q. Has Mr. Kind previously addressed Section 5.3 of the Service Agreement in his testimony in this proceeding regarding his concern about the Commission continuing to set the transmission component of Ameren Missouri's bundled retail load?

A. Yes. In his Rebuttal Testimony at page 10, lines 29 - 33, he states that with the creation of ATX (Ameren Transmission Company) and Ameren's stated intention for ATX to invest in and own new transmission:

> . . . the provisions in Section 5.3 of the Service Agreement are no longer sufficient to "ensure that the Commission continues to set the transmission component of Ameren Missouri's bundled retail load."

Q. Has Mr. Kind provided any additional information explaining why Section 5.3 is no longer adequate to ensure that the Commission continues to set the transmission component of Ameren Missouri's bundled retail load even under the Case No. EO-2008-0134 Stipulation And Agreement?

A. Yes. At page 13, lines 1-9 of his Rebuttal Testimony, there is a discussion of the Midwest ISO TOA. Mr. Kind testifies that the Midwest ISO TOA's definition of "Owner" states "a public utility holding company system shall be treated as a single Owner for purposes of this agreement." Thus, Mr. Kind states "the Ameren holding company (Ameren) will be able to choose to have ATX build transmission projects in Missouri, instead of UE."

Q. Does Ameren Missouri concur with Mr. Kind's interpretation of the definition of "Owner" in the Midwest ISO's TOA?

A. Yes, it appears so. Ameren Missouri Witness Maureen A. Borkowski explained in her Surrebuttal Testimony that under the Midwest ISO TOA, each of the Ameren transmission-owning companies, Ameren Missouri, Ameren Transmission Company of Illinois (ATXI), and Ameren Illinois Company (AIC), has the right and obligation to build a transmission project that connects to the transmission owner's combined system, pre-FERC Order No. 1000, page 8, line 21 - page 9, line 2.

Q. Does Mr. Kind allude in his Supplemental Rebuttal testimony to the Federal RoFR, which is affected by FERC Order 1000?

A. Possibly yes, at page 7, lines 18-21:

> . . . In those prior cases there was never any reason to consider the possibility of UE giving up the *rights* that it had under the MISO Transmission Owners Agreement to construct and own new transmission facilities in Missouri that are part of the MISO transmission expansion plan. . . . [Italics added.]

The Federal RoFR, affected by FERC Order 1000, currently gives Ameren Missouri the first right to build transmission in the Ameren Missouri service territory, but the Midwest ISO TOA gives the right and obligation to not only Ameren Missouri, but also to other members of the Ameren holding company both pre- and post-FERC Order 1000 for transmission projects for which Ameren Missouri retains the Federal RoFR until it ends.

Q. Does Mr. Kind mention in his Supplemental Rebuttal Testimony that this right will not exist in the future for transmission projects as a result of FERC Order 1000 except as you have noted above?

A. No.

Q On page 10 of his Supplemental Rebuttal Testimony, beginning on line 25, Mr. Kind puts forth an assumption where "ATX or one of its subsidiaries constructs and owns transmission facilities in Missouri that would have otherwise been constructed and owned by UE." Is this a reasonable assumption in post-FERC Order 1000?

A. No, it is not. The transmission projects that Ms. Borkowski describes in her Surrebuttal Testimony on page 6, beginning at line 5, will no longer have a Federal RoFR. Ms. Borkowski describes the remaining Federal RoFR and plans for Ameren Missouri and other Ameren affiliates to build transmission projects in Missouri as follows:

> . . . Ameren Missouri intends to build projects the Midwest ISO designates as "Baseline Reliability" projects and "Generation Interconnection" and

> "Transmission Service" projects if the generation or transmission customer for whom the project is constructed is Ameren Missouri. ATX or another Ameren subsidiary intends to build other transmission in Missouri. This would include projects the Midwest ISO designates as Multi-Value Projects ("MVPs"), Market Efficiency Projects ("MEPs"), and Generation Interconnection and Transmission Service Projects built for customers other than Ameren Missouri. These projects are all justified and approved for inclusion in the Midwest ISO Transmission Expansion Plan for reasons other than the need to provide reliable service to Ameren Missouri customers. Their costs are primarily allocated to entities other than Ameren Missouri. In fact, Ameren Missouri would be allocated far less than half of the cost of any of these projects. . . .

This "other transmission" described in the above excerpt will be subject to regional cost allocation – that is, paid for by regions other than where the project is built. The first bullet of the FERC Staff briefing of Slide 17 states that the FERC Order 1000 Federal RoFR elimination "does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation."

The following chart from a slide included in a Midwest ISO staff presentation called "MISO Transmission Cost Allocation Overview" dated October 3, 2011, describes the different types of transmission projects within the MISO footprint, including their cost allocation ("titled "Allocation to Beneficiaries"):

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission Owner identified project that does not qualify for other cost allocation mechanisms.	Paid by requestor (local zone)
Generation Interconnection Project	Interconnection Request	Paid for by requestor; 345 kV and above 10% postage stamp to load
Market Efficiency Project[1]	Reduce market congestion when benefits are 1.2 to 3 times in excess of cost	Distribute to planning regions commensurate with expected benefit; 345 kV and above 20% postage stamp to load
Baseline Reliability Project	NERC Reliability Criteria	Primarily shared locally through Line Outage Distribution Factor Methodology; 345 kV and above 20% postage stamp to load
Multi Value Project	Address energy policy laws and/or provide widespread benefits across footprint	100% postage stamp to load

The full Midwest ISO staff presentation is attached as Schedule ACM-2.

The Market Efficiency Projects and the MultiValue Projects in the chart above have cost allocation shared regionally (especially the MultiValue Projects). These are the sort of projects described by Ms Borkowski as intending to be built by ATX or another Ameren subsidiary, and the type of projects that will not be covered by the Federal RoFR post-FERC Order 1000.

Q. Are you aware whether the Midwest ISO staff has made any presentation on which planned transmission construction projects will retain the Federal RoFR in the Midwest ISO after FERC Order 1000?

A. The Midwest ISO staff held its first "Order 1000 Right of First Refusal (RoFR) Workshop" on Wednesday February 1, 2012. At the workshop, stakeholders gave presentations on Federal RoFR, including what transmission projects they saw as retaining the Federal RoFR and which ones would not.

The Midwest ISO staff indicated at the end of the workshop that it would draw up a straw proposal on Federal RoFR issues, including which projects would retain the Federal RoFR, for the next Midwest ISO "Order 1000 Right of First Refusal (RoFR) Workshop" scheduled for February 29, 2012.

<u>Commission's Ability to Set the Transmission Component of the Bundled Retail Rate</u>

Q. At page 8, lines 22-23 of his Supplemental Rebuttal Testimony, does Mr. Kind provide an explanation as to how his statement "one must assume that all of the signatories to the Agreement believe that the Commission **currently** has this jurisdiction" [Emphasis in original] over the transmission component of the rates set for Bundled Retail Load, applies to Staff's position in this case?

A. No. Although I understand Mr. Kind is not an attorney, he provides no reference to page 20, line 22 - page 21, line 6 of my Rebuttal Testimony, in this case where I stated:

> Q. Do you know whether, in the legal opinion of Staff Counsel's Office, Ameren Missouri Affiliates, including Ameren Transmission Company ("ATX"), need a Commission Certificate of Convenience and Necessity (CCN) in order to construct, own, and operate certain transmission facilities in the state of Missouri?
>
> A. It is my understanding that it is Staff Counsel's Office legal opinion that Ameren Missouri affiliates, including ATX, would need a CCN (as described in RSMo 393.170 and 393.190.1) to construct, own, and operate certain transmission facilities in Missouri.

Again, I am not an attorney and will leave the matter of Staff's position that Ameren Missouri affiliates building transmission require a CCN from the Commission to Staff attorneys, but this position of the Staff is directly related to the Staff's position on the Commission's jurisdiction over the transmission component of the rates set for Bundled Retail Load. Staff counsel advises me that Section 393.170 is the CCN statutory section, and contains a provision in Section 393.170.3 that "[t]he commission may by its order impose such condition or conditions as it may deem reasonable and necessary" as part of the grant of a CCN.

Q. In your opinion, does Mr. Kind's Supplemental Rebuttal Testimony indicate the Staff's position results in a loss of Missouri Commission jurisdiction?

A. Yes, on page 10, lines 22 – 24, Mr. Kind states: "Subsection 10.j. is essentially a Band-Aid. It is designed to last for just a few years and ignores the harm from the loss of jurisdiction that will last for decades." Further, on page 11 of his Supplemental Rebuttal Testimony, beginning on line 3, Mr. Kind describes a situation in which Ameren Missouri customers would pay charges based on ATX considerations, including the MISO tariff-authorized 12.38% return on equity. These statements ignore Staff's position regarding the requirement of a CCN for non-Ameren Missouri builders of transmission in Ameren Missouri's service territory, and the fact that Ameren Missouri will have to return to the Commission for further authorization to continue to participate in the Midwest ISO.

On advice of Staff counsel, a future CCN case for an Ameren Missouri affiliate to construct transmission facilities would be a vehicle for the Commission to effectuate conditions to preserve Commission control over the transmission component of the bundled retail rate to Ameren Missouri retail customers. For example, the Commission could order conditions or accept parties' stipulation and agreement that would allow Ameren Missouri customers to pay rates including costs for transmission projects constructed by the Ameren Missouri affiliate as if Ameren Missouri were constructing the projects. Again, on advice of Staff counsel, if the Ameren Missouri affiliate did not file with the Commission for a CCN but just commenced to construct transmission facilities, the Staff Counsel's Department could commence proceedings against the Ameren Missouri affiliate for failure to apply for a CCN. Some other entity, such as OPC, might also commence similar proceedings.

Q. Does Mr. Kind provide an "Alternative Approach" on page 13, of his Supplemental Rebuttal Testimony, to Subsection 10.j. of the Non-unanimous Stipulation and Agreement?

A. Yes, he does, starting on line 12. Mr. Kind provides some alternative language regarding "Transmission Rate Incentives:"

> *Transmission Rate Incentives. Ameren Missouri acknowledges that the Service Agreement's primary function is to ensure that the MoPSC continues to set the transmission component of Ameren Missouri's rates to serve its Bundled Retail Load. Consistent with Section 3.1 of the Service Agreement and its primary function, to the extent that the FERC offers "Transmission Rate Incentives" pursuant to Section 219 of FERC Order No. 679 as part of the revenue requirement for providing Transmission Service (as that term is defined in the Service Agreement) to wholesale customers within the Ameren zone, such "Transmission Rate Incentives" shall not apply to the transmission component of rates set for Bundled Retail Load by the MoPSC.* [Italics in original.]

Mr. Kind says this language will, on page 13, beginning on line 22:

> . . . (1) provide long-term and comprehensive rate protection to UE's Missouri retail customers; and (2) not diminish the Commission's jurisdiction over the transmission component of the rates set for Bundled Retail Load.

Q. Is Mr. Kind proposing language different from prior stipulation and agreements from previous cases involving Ameren Missouri participation in the Midwest ISO?

A. Yes. It appears that Mr. Kind's suggested language is intended to cover items he lists on page 12, lines 15-17 of his Supplemental Rebuttal Testimony (abandoned plant recovery, recovery on a current basis instead of capitalizing precommercial operations expenses, and accelerated depreciation) in addition to capital structure, return on equity (ROE), and construction work in progress (CWIP). After FERC's adoption of Order No. 679, Promoting Transmission Investment Through Pricing Reform, issued July 20, 2006, various parties in Case No. EO-2008-0134, Ameren Missouri's Midwest ISO case preceding Ameren Missouri's present Midwest ISO case, executed a Stipulation and Agreement in settlement of Case No. EO-2008-0134. The section on incentive adders in the Case No. EO-2008-0134 Stipulation and Agreement was no more specific than Section 10.c. in the present Non-unanimous Stipulation and Agreement.

Mr. Kind's proposed language, among other things, refers to Section 219 of FERC Order No. 679, which I think is an incorrect reference. Mr. Kind probably meant to refer to the new Section 219 of the Federal Power Act.

Q. What about Mr. Kind's argument that the Non-unanimous Stipulation and Agreement does not provide long-term rate protection?

A. As I have previously addressed, it is the Staff Counsel Department's position that an Ameren Corporation entity that seeks to construct transmission in Missouri needs a CCN from this Commission. Also, Ameren Missouri must return to the Commission in the future for continuing authority to participate in the Midwest ISO.

<u>When the Midwest ISO Has Indicated the Federal RoFR Will End</u>

Q. Can you provide any additional detail regarding which transmission projects in Midwest ISO in Missouri will have the Federal RoFR, and which will not?

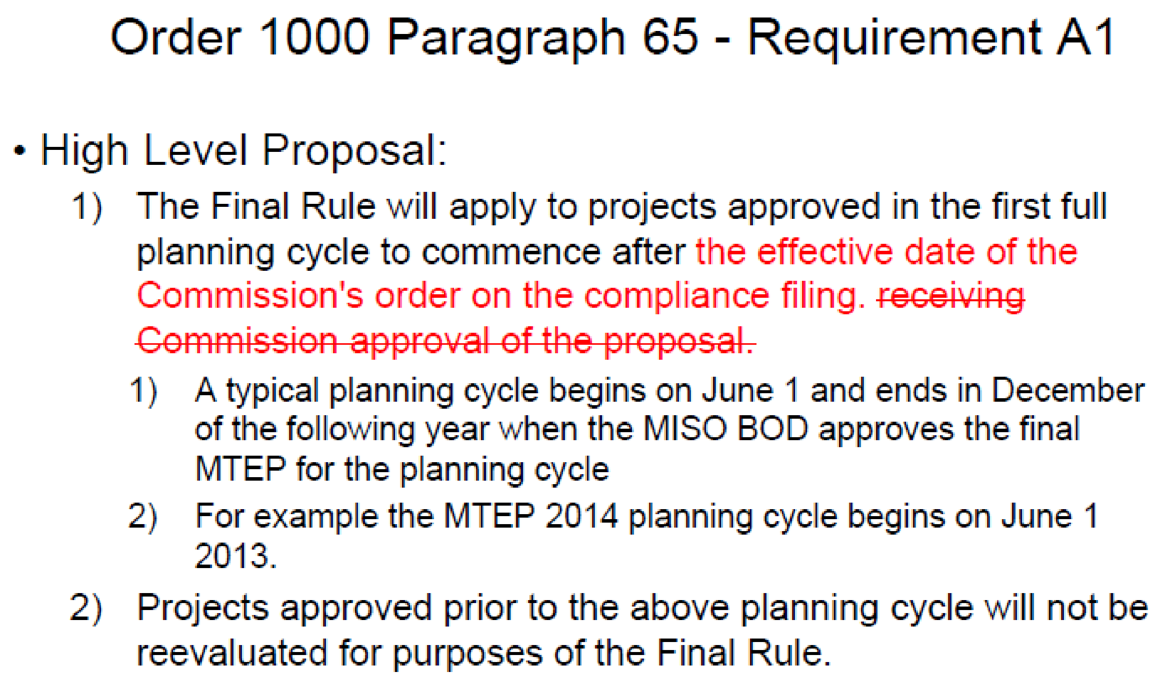
A. Yes. First, there is Paragraph 65 of FERC Order 1000:

> We also clarify that the requirements of this Final Rule are intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule. The requirements of this Final Rule will apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's

> filing adopting the transmission planning and cost allocation reforms of the *pro forma* OATT required by this Final Rule. We appreciate that transmission facilities often are subject to continuing evaluation as development schedules and transmission needs change, and that the issuance of this Final Rule is likely to fall in the middle of ongoing planning cycles. Each region is to determine at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the requirements of this Final Rule. Our intent here is that this Final Rule not delay current studies being undertaken pursuant to existing regional transmission planning processes or impede progress on implementing existing transmission plans. We direct public utility transmission providers to explain in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule. [Footnote omitted.]

In addition, the Midwest ISO Staff, as part of its proposal on how to comply with FERC Order 1000, made a presentation at the January 25, 2012 Planning Activities Committee (PAC) meeting, discussing when the effects of FERC Order 1000, including the removal of the Federal RoFR, would apply to projects approved by the Midwest ISO Board of Directors (BOD). The full presentation is attached as Schedule ACM-3.

Slide 5 of the presentation contains the following:



The preceding slide states in part "[t]he high level proposal attempts to establish a clean break by beginning the implementation of the provisions of the compliance filing with the start of a new planning cycle. As such, MISO would like to slightly modify the wording of the high level proposal as shown in red on the following slide."

I asked for and received clarification from Midwest ISO staff analysts Matthew Tackett and Laura Rauch. According to the Midwest ISO staff's interpretation, under the "High Level Proposal" above, the Federal RoFR would still be in place for all MISO Transmission Expansion Plans (MTEPs) up to at least MTEP14 – that is, the projects approved by the MISO Board of Directors at the end of the year 2014. An e-mail providing that clarification is attached as Schedule ACM-4.

Q. Under what circumstances would MTEP14 be the first set of Midwest ISO Board of Directors approved transmission projects without a Federal RoFR under the Midwest ISO staff proposal?

A. The Midwest ISO is required to make a compliance filing with FERC to meet all requirements of FERC Order 1000 except interregional cost allocation by October 2012. The Midwest ISO staff's proposal is to have FERC Order 1000 requirements, including the removal of the Federal RoFR, apply to the first full planning cycle after the effective date of the FERC Order on that October 2012 compliance filing.

The Midwest ISO planning cycles are 18-month periods of time, beginning in June and concluding in December of the following year. For example, the MTEP14 planning cycle begins in June 2013 and lasts until December 2014.

If FERC issues an Order on the Midwest ISO October 2012 compliance filing with an effective date before June 1, 2013, the MTEP14 planning cycle would be the first planning cycle to begin after the effective date.

However, if the effective date of the FERC Order on the MISO October 2012 compliance filing is after June 1, 2013, then MTEP15, with analysis beginning on June 1, 2014, would be the first planning cycle without a Federal RoFR.

The following chart shows the starting and ending dates of the most recent Midwest ISO planning cycle and future planning cycles, and how the effective date of the FERC Order for the Midwest ISO FERC Order 1000 compliance filing due October 2012 would affect which planning cycles have the Federal RoFR:

Federal RoFR Exists in the Midwest ISO Transmission Owners Agreement.

June 2010 → December 2011 = MTEP11
Includes the Mark Twain Project MVP in Missouri
June 2011 → December 2012 = MTEP12
June 2012 → December 2013 = MTEP13

Midwest ISO Staff Expects Federal RoFR Ends For Certain "Categories" of Projects, Based on the Date of FERC Order Approving MISO Compliance Filing Due October 2012. All Future MTEPs Will Not Have the Federal RoFR except as noted above on page 4.

June 2013 → December 2014 = MTEP14
June 2014 → December 2015 = MTEP15

Q. Is there a Federal RoFR for projects, including the MVPs, scheduled to be built in Missouri that were approved by the Midwest ISO Board of Directors in December 2011?

A. Yes, there is since the planning cycle was from June 2010 to December 2011, and during that entire period of time the Federal RoFR was in effect.

Q. Does MTEP11 include the Mark Twain MVP in northern Missouri, planned to go from Ottuma, IA to Adair, Missouri and then east to Palmyra, Missouri?

A. Yes, it does.

Q. Under the Midwest ISO Staff proposal from the January 25, 2012 PAC Meeting, will there be a Federal RoFR for any projects approved by the Midwest ISO Board of Directors in late 2012 for MTEP12?

A. Yes, there would be since the planning cycle will be from June 2011 to December 2012, and the Midwest ISO has stated that its plan is to make the FERC Order compliance filing in October 2012.

Arkansas Public Service Commission Docket No. 10-011-U, Order No. 54

Q. Does Mr. Kind quote from an October 28, 2011 Arkansas Public Service Commission (Arkansas Commission) Order No. 54 in Docket No. 10-011-U at page 24 of his

Supplemental Rebuttal Testimony respecting Entergy Arkansas, Inc.'s post-Entergy System Agreement reorganization options?

A. Yes, he does, but there is a subsequent Order No. 56, dated December 6, 2011, of the Arkansas Commission of which he does not make note. Entergy Arkansas, Inc. filed a Petition for Clarification, Or, In the Alternative, Rehearing, respecting Order No. 54. The General Staff of the Commission filed a response stating that Order No. 54 was not a final and appealable Order. In Order No. 56, the Arkansas Commission stated that it issued Order No. 54 providing guidance to Entergy Arkansas, Inc. and Order No. 54 is not a final decision:

> Order No. 54 was intended to provide EAI [Entergy Arkansas, Inc.] guidance as it prepares to operate post-ESA [Entergy System Agreement] on or before December 18, 2013. Order No. 54 is not a final decision by the Commission regarding the matters in this Docket. As a result, EAI's alternative request for a rehearing is moot.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Federal Energy Regulatory Commission

FINAL RULE ON

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Briefing on Order No. 1000 Presented by
Federal Energy Regulatory Commission Staff

The statements herein do not necessarily reflect the views of the Commission

Timeline

Federal Energy Regulatory Commission

- Order No. 888 in 1996
  - Requires open access to transmission facilities to address undue discrimination and to bring more efficient, lower cost power to the Nation's electricity consumers
- Order No. 890 in 2007
  - Requires coordinated, open and transparent regional transmission planning processes to address undue discrimination
- Order No. 1000 in 2011
  - Requires transmission planning at the regional level to consider and evaluate possible transmission alternatives and produce a regional transmission plan
  - Requires the cost of transmission solutions chosen to meet regional transmission needs to be allocated fairly to beneficiaries

2

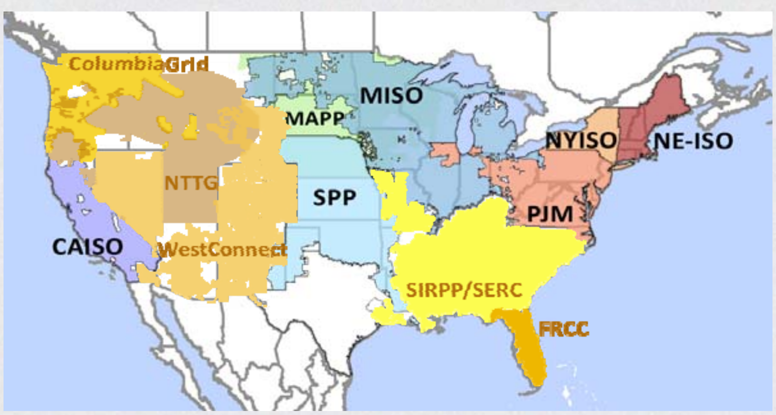
Order No. 1000

Federal Energy Regulatory Commission

- Planning Requirements
- Cost Allocation Requirements
- Nonincumbent Developer Requirements
- Compliance

Current Transmission Planning Regions *

Federal Energy Regulatory Commission



- This map is for illustration purposes only. This map generally depicts the borders of regional transmission planning processes through which transmission providers have complied with Order No. 890. Those borders may not be depicted precisely for several reasons (e.g., not all transmission providers complying with Order No. 890 have a defined service territory). Additionally, transmission planning regions could alter because transmission providers may choose to change regions.
- Source: Derived from Energy Velocity

Important Terms

Federal Energy Regulatory Commission

- Rule distinguishes between a transmission facility "in a regional transmission plan" and "selected in a regional transmission plan for purposes of cost allocation"
- Rule's requirements apply to "new transmission facilities," which are those subject to evaluation or reevaluation within local or regional transmission planning processes after the effective date of compliance filings

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Federal Energy Regulatory Commission

PLANNING REQUIREMENTS

6

Planning Requirements

Federal Energy Regulatory Commission

1. Public utility transmission providers are required to participate in a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations
3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if more efficient or cost-effective solutions are available

7

Regional Planning

Federal Energy Regulatory Commission

- Each transmission planning region must produce a regional transmission plan reflecting solutions that meet the region’s needs more efficiently or cost-effectively
- Stakeholders must have an opportunity to participate in identifying and evaluating potential solutions to regional needs

8

Planning for Public Policy Requirements

Federal Energy Regulatory Commission

- Each public utility transmission provider must establish procedures to:
  - Identify transmission needs driven by public policy requirements
  - Evaluate potential solutions to those needs
- Public policy requirements are defined as enacted statutes and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level
- No mandate to include any specific requirement

9

Interregional Coordination

Federal Energy Regulatory Commission

- Each pair of neighboring transmission planning regions must:
  - Share information regarding the respective needs of each region and potential solutions to those needs
  - Identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs
- Interregional transmission facilities are those that are located in two or more neighboring transmission planning regions
- No requirement to produce an interregional transmission plan or engage in interconnectionwide planning

10

COST ALLOCATION REQUIREMENTS

Federal Energy Regulatory Commission

11

Cost Allocation Requirements

Federal Energy Regulatory Commission

1. Regional transmission planning process must have a regional cost allocation method for a new transmission facility selected in the regional transmission plan for purposes of cost allocation
   - Cost allocation method must satisfy six regional cost allocation principles
2. Neighboring transmission planning regions must have a common interregional cost allocation method for a new interregional transmission facility that the regions select
   - Cost allocation method must satisfy six similar interregional cost allocation principles
3. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method

12

Cost Allocation Principles

Federal Energy Regulatory Commission

- Costs allocated "roughly commensurate" with estimated benefits
- Those who do not benefit from transmission do not have to pay for it
- Benefit-to-cost thresholds must not exclude projects with significant net benefits
- No allocation of costs outside a region unless other region agrees
- Cost allocation methods and identification of beneficiaries must be transparent
- Different allocation methods could apply to different types of transmission facilities

13

Cost Allocation

Federal Energy Regulatory Commission

- The rule does not require a one-size fits all method for allocating costs of transmission facilities
  - Each region is to develop its own proposed cost allocation method(s)
- If region can't decide on a cost allocation method, then FERC would decide based on the record
- No interconnectionwide cost allocation

14

Federal Energy Regulatory Commission

NONINCUMBENT DEVELOPER REQUIREMENTS

15

Nonincumbent Developers

Federal Energy Regulatory Commission

- Rule promotes competition in regional transmission planning processes to support efficient and cost effective transmission development
- Rule requires the development of a not unduly discriminatory regional process for transmission project submission, evaluation, and selection

16

Nonincumbent Developers

Federal Energy Regulatory Commission

Rule removes any federal right of first refusal from Commission-approved tariffs and agreements with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:

- This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation
- This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring
- This allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers
- Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities

17

Compliance

Federal Energy Regulatory Commission

- Each transmission provider is required to make a compliance filing within twelve months of the effective date of the Final Rule
- The compliance filings for interregional transmission coordination and interregional cost allocation must be filed within eighteen months of the effective date

18

Outreach

Federal Energy Regulatory Commission

FERC plans 3 webinars (early Fall) to aid compliance:

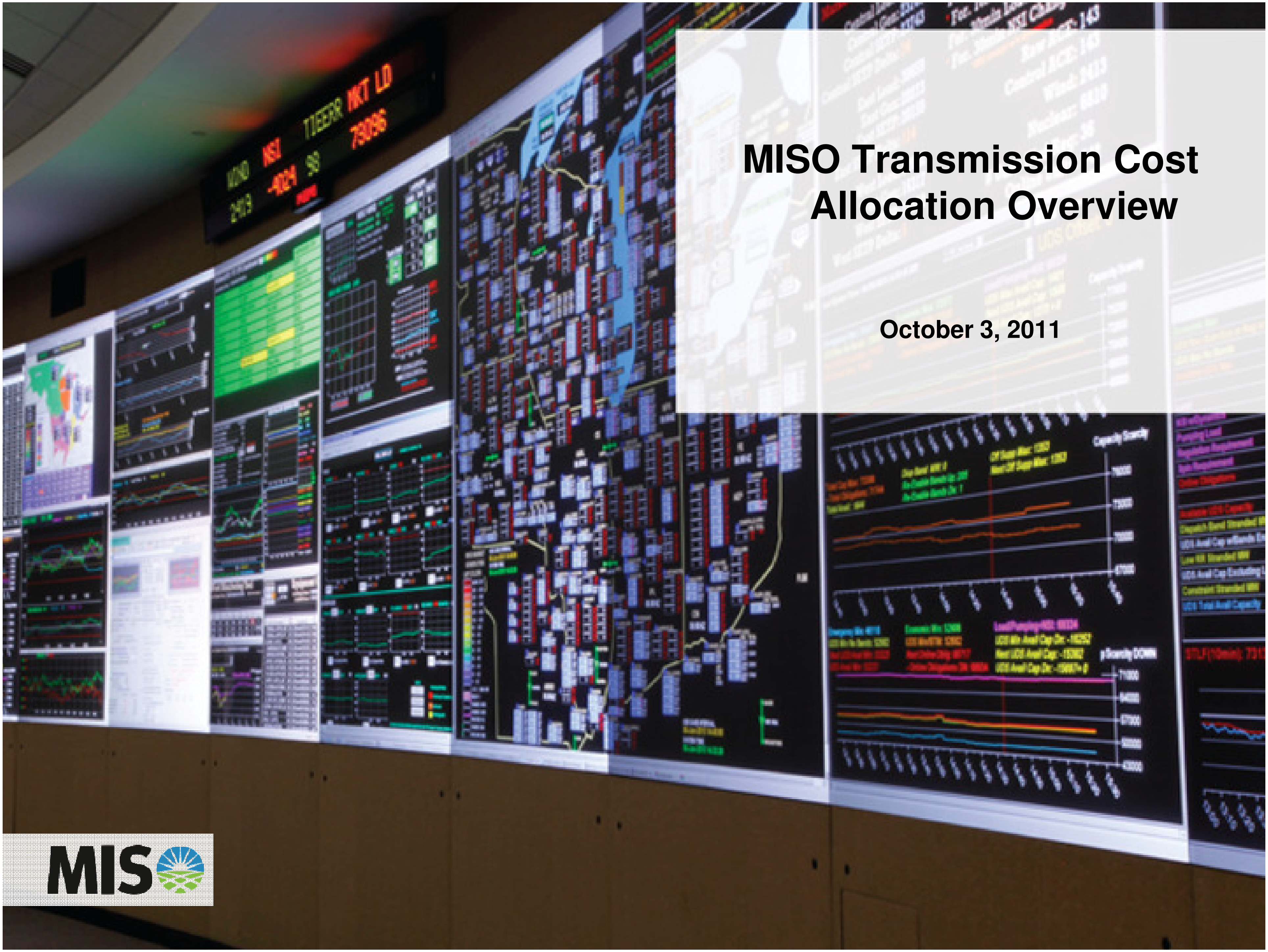
- RTO regions
- Eastern (non-RTO)
- Western (non- RTO)

For updates, please follow us:

Twitter twitter.com/ferc

Facebook facebook.com/ferc.gov

RSS ferc.gov/xml/whats-new.xml



MISO Transmission Cost Allocation Overview

October 3, 2011

MISO

The MISO transmission cost allocation approach seeks to match the business case with the allocation method*

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission Owner identified project that does not qualify for other cost allocation mechanisms.	Paid by requestor (local zone)
Generation Interconnection Project	Interconnection Request	Paid for by requestor; 345 kV and above 10% postage stamp to load
Market Efficiency Project[1]	Reduce market congestion when benefits are 1.2 to 3 times in excess of cost	Distribute to planning regions commensurate with expected benefit; 345 kV and above 20% postage stamp to load
Baseline Reliability Project	NERC Reliability Criteria	Primarily shared locally through Line Outage Distribution Factor Methodology; 345 kV and above 20% postage stamp to load
Multi Value Project	Address energy policy laws and/or provide widespread benefits across footprint	100% postage stamp to load

1. Market Efficiency Project cost allocation methodology currently under review by stakeholders

MISO

** For additional information see Attachment FF of the Tariff at https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx*

Baseline Reliability Projects

- Qualification
  - Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Entities and applicable to the MISO Transmission System
  - Project cost must be greater than $5 million or represent 5% of the constructing Transmission Owner's Net Transmission Plant per Attachment O
- Cost Allocation
  - For network upgrades between 100 kV and 345 kV
    - 100% of costs allocated to affected pricing zones based on Line Outage Distribution Factor (LODF)
  - For network upgrades ≥ 345 kV
    - 20% of costs allocated system-wide to all load based on load ratio share
    - 80% of costs allocated to affected pricing zones based on Line Outage Distribution Factor (LODF)

MISO

Baseline Reliability Projects – LODF Methodology

- LODF determines the impact of the new facility on other existing components of the transmission system to determine the allocation of costs across pricing zones
  - Calculated using PSS/E MUST to estimate power flow under two scenarios (i.e. system with and without the new facility)
  - Output is the absolute percentage change in power flow over existing components between the two scenarios
    - $LODF = Abs((PF_2 – PF_1) / PF_2)$
  - Individual values are weighted by line mileage and summed to determine share of project cost allocated to each pricing zone

Generation Interconnection Projects

- Qualification
  - Network upgrades identified through Interconnection study are eligible for sharing
  - No minimum project cost requirement
- Cost Allocation
  - Generator pays 100% of network upgrades less than 345kV
  - Generator pays 90% of network upgrades greater than or equal to 345kV with the remaining 10% shared system-wide based on load ratio share

MISO

Generation Interconnection Projects

- Prior to construction the Interconnection Customer funds 100% of network upgrades
- Upon Commercial Operation, the Transmission Owner has one of two options:
  - Repay 100% of the costs to the Interconnection Customer and charge a monthly payment to recover the 90% or 100% generator piece, or
  - Repay 10% of the costs to Interconnection Customer if Network Upgrades are 345 kV or greater
- Shared Network Upgrades
  - Allows first-movers to recover costs from later generators who benefit from their existing Network Upgrades
  - Identification based on physical location of interconnection point or flow-based screening criteria to measure impact on eligible upgrades
  - Eligibility for refund limited to five years after in-service date
- ATC and all ITC zones have 100% reimbursement to generators

MISO

Market Efficiency Projects

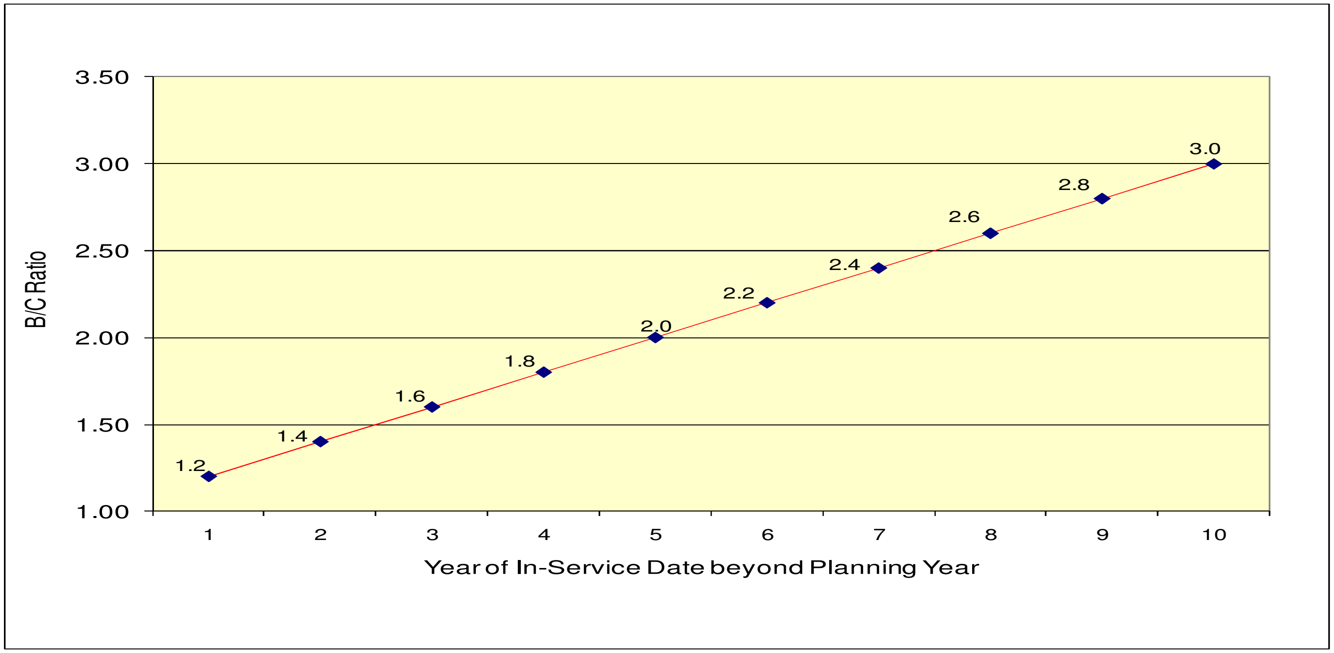
- Qualification
  - Network upgrades that are shown to have regional economic benefits as demonstrated through multi-metric and multi-year planning guided by the Planning Advisory Committee
  - Involve facilities operating at voltages ≥ 345 kV
  - Project cost must be > $5 million
    - With at least 50% of the project cost associated with 345 kV or above facilities
  - Annual Benefits calculated using the following two metrics:
    - 70% Adjusted Production Cost Savings
      - Adjusted Production Cost is equal to the total production cost of the generation fleet adjusted for import costs and export revenue
    - 30% Load Cost Savings
      - Load Cost is equal to the MW of load multiplied by the load-weighted LMP
    - "Savings" for each metric is the difference between two cases: 1) base case without the project; and 2) case with the project
    - Weighted-Gain No Loss provision prohibits allocation of costs to planning sub-regions that do not see benefits from project

** Market Efficiency Project cost allocation methodology currently under review at the RECBTF.

Market Efficiency Projects B/C Ratio Criteria

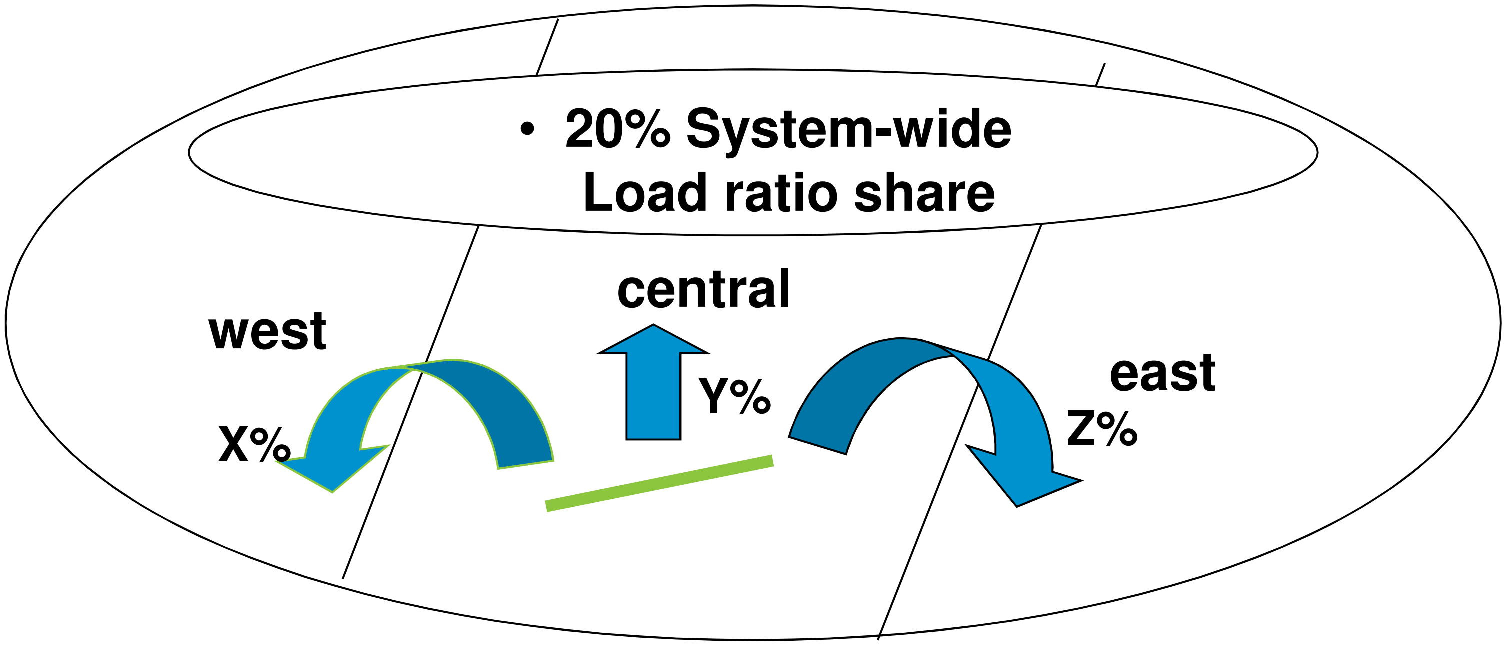
- Must meet a sliding-scale benefit/cost ratio threshold based on the project's in-service date:

$$Benefit/Cost\ Ratio = \frac{\sum_{i=0}^{N} (70\%\ Annual\ APC\ Savings_N + 30\%\ Load\ LMP\ Savings_N) \big/ (1 + D.R.)^t}{\sum_{i=0}^{N} Annual\ Revenue\ Requirement_N / (1 + D.R.)^t}$$



** Market Efficiency Project cost allocation methodology currently under review at the RECBTF.

Market Efficiency Project Cost Allocation Methodology



- 80% of project costs to Planning Sub-Regions based on share of congestion-based benefit metric (X,Y,Z)
  - Load ratio share within each Planning Sub-Region
- 20% system-wide based on load ratio share

** Market Efficiency Project cost allocation methodology currently under review at the RECBTF.

Multi Value Projects

Multi Value Projects must meet one of the three Tariff defined criteria

Criterion 1

A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

Criterion 2

A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.

Criterion 3

A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.6 of Attachment FF.

Other MVP Requirements

- Must be evaluated as part of a portfolio of projects, as designated in the MISO transmission expansion planning process, whose benefits are spread broadly across the footprint
- Must not be in-service, under construction or approved by the MISO Board prior to July 16, 2010 or the date a Transmission Owner becomes a signatory member of the ISO Agreement, whichever is later
- Must have a project cost greater than $20 million or represent 5% of the constructing Transmission Owner's net transmission plant as defined in Attachment O
- Must be evaluated through the MISO transmission expansion planning process and approved by the MISO Board of Directors

Other MVP Requirements, cont.

- Project must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV
- Projects driven solely by an Interconnection Request or Transmission Service Request do not qualify
- Cannot contain facilities in the MISO excludes list, Attachment FF-1

Other MVP Requirements, cont.

- Should a project qualify as a Multi Value Project and also qualify as either a Baseline Reliability Project, Market Efficiency Project, or both, the project will be designated as a Multi Value Project and not as a Baseline Reliability Project or Market Efficiency Project.
- Any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits will not qualify for cost sharing.
- Any DC transmission line and associated terminal equipment will not qualify for cost sharing when scheduling and dispatch of the DC transmission line is not turned over to the MISO markets, real-time control of the DC transmission line is not turned over to the MISO automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service.

MVP Benefit-to-Cost Ratio Calculation for Qualification under Criterion 2 or 3

- Total MVP B/C Ratio =

  $\sum$ PV Projects Benefits(yr_i) / $\sum$ PV Project Costs(yr_i)
- Total MVP B/C Ratio must be greater than or equal to 1.0 for further consideration as an MVP under Criteria 2 or 3
- Benefits and Costs (i.e. Annual Revenue Requirement) are calculated for the first 20 years of a project's useful life
- Risk-adjusted discount rate will be used
- Types of quantifiable benefits to be considered in calculating the Total MVP B/C ratio are listed on the next page

MISO

Examples of Economic Value Identified in Tariff that May be Quantified for Multi Value Projects

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

Multi Value Project Cost Allocation Methodology

- 100% of the annual revenue requirements for Multi Value Projects are allocated on a system-wide basis to Transmission Customers that withdraw energy from the MISO system including export and through transactions sinking outside the MISO region (excluding PJM), and recovered through an MVP Usage Charge as described in Attachment MM.

Calculation of Annual Revenue Requirements and Rates for Cost Shared Transmission Projects

MISO

Calculating Annual Revenue Requirements for Cost Shared Transmission

- Transmission Owner provided information
  - All TOs submit Attachment O data
    - Submitted either by May 1 for historic TOs or December 1 for forward-looking TOs
    - TO's Att. O revenue requirement to determine Schedule 7, 8, and 9 rates are adjusted based on Att. GG (BRP, GIP, MEP) and MM (MVP) revenue requirement amount calculated to avoid over-recovery
  - TOs that have eligible cost shared projects submit Attachment GG template for BRPs, GIPs, and MEPs or Attachment MM template for Multi Value Projects
    - Necessary information to complete Attachment GG/MM comes from Attachment O and the "MTEP Project Completion" template
    - Att. GG/MM is used to calculate the Annual Revenue Requirement for eligible cost shared projects
      - TOs that have received FERC approval for Construction Work In Progress (CWIP) can submit revenue requirements for recovery prior to a project being in-service
  - Methodology to calculate Annual Revenue Requirement is the same for Attachment GG (BRP, GIP, MEP) and Attachment MM (Multi Value Projects)

Calculating Annual Revenue Requirements for Cost Shared Transmission (cont.)

- Annual Allocation factors are calculated for each of the following cost of service elements based on the current cost structure for the entire Transmission Owner system:
  - Operation and Maintenance Expense (based on Gross Transmission Plant)
    - includes Transmission O&M and Administrative & General Expenses
  - General and Common Depreciation Expense (based on Gross Transmission Plant)
    - examples include office buildings, computers, etc…
  - Taxes Other than Income Taxes (based on Gross Transmission Plant)
    - examples include payroll and property taxes
  - Income Taxes (based on Net Transmission Plant)
    - Federal and State Income Taxes
  - Return on Rate Base (based on Net Transmission Plant)
    - Rate of Return based on the Weighted Average Cost of Capital including long-term debt, preferred stock, and common stock
      - For those under FERC jurisdiction the Return on Equity must be approved by FERC
- In addition to the five cost of service elements a project specific depreciation expense is included in the annual revenue requirement
- Total Annual Revenue Requirement for a project is equal to the five cost of service elements plus the project specific depreciation expense

MISO

Overview of Schedule 26

- Schedule 26 – Network Upgrade Charge for BRP, GIP, and MEP
  - Demand based charge for Transmission Service in addition to Schedules 7, 8, or 9 depending on the type and duration of Transmission Service taken
  - For Point-to-Point Transmission Service that sinks in PJM Schedule 26 is discounted to zero
  - Load served under Grandfathered Agreements are not charged Schedule 26
  - Rates updated January 1 and June 1 of each year
  - Invoiced Monthly

Overview of Schedule 26-A

- MVPs are charged to Monthly Net Actual Energy Withdrawals (MNAEW), Export Schedules, and Through Schedules proportional to the amount of energy withdrawn from the system
  - Export and Through Schedules sinking in PJM are excluded from MVP charges
- Formulas used to calculate MVP Usage Rate ($/MWh)
  - MVP Usage Rate = (Total MVP Annual Revenue Requirements * Monthly Withdrawal Weighting Factor) / (Monthly Net Actual Energy Withdrawals + monthly Real-Time Export Schedules + monthly Real-Time Through Schedules + MWhs of service provided under GFAs)
  - Monthly Withdrawal Weighting Factor = Applicable Month Prior Year Withdrawals / Total Prior Year Withdrawals

– Invoiced Monthly

MISO

Cross-Border Cost Sharing with PJM

Cross-Border Cost Sharing with PJM

- Cross-Border Baseline Reliability Project (CBBRP) Criteria:
  - Must be a Baseline Reliability Project as defined in the MISO and PJM Tariffs
  - A minimum of $10 million in Project Cost must be allocated to the RTO in which the project is not constructed
  - RTO where is project is not constructed must contribute at least 5% to the total loading on the constrained facility
  - Costs allocated to each RTO based on a DFAX calculation that determines the MW flow impact attributable to each RTO on the constraint requiring the upgrade
  - Each RTO will then allocate their respective shares in accordance with their Tariff
  - Annual Revenue Requirements determined by Attachment CC (similar to Attachment GG and MM) if the project is located in MISO and charged through Schedule 25

MISO

** Additional detail available in the JOA between MISO and PJM in Article IX.

Cross-Border Cost Sharing with PJM (cont.)

- Cross-Border Market Efficiency Project
  - Must have an estimated Project Cost of $20 million or greater
  - Project must meet a Benefits-to-Cost threshold of 1.25 based on the following Benefits and Costs calculation:
    - Annual Benefit Metric = (70% of change in APC + 30% of change in Net Load Payment)
      - Net Load Payment = (Load LMP * Load) – Value of Congestion Hedging Transmission Rights
    - Annual Project Costs are based on annual charge rate of the constructing Transmission Owner
    - Calculated over first 10 years of project life with a maximum planning horizon of 20 years from the current year
    - Present value of annual benefits and costs calculated using a discount rate based on the weighted average cost of capital for Transmission Owners in each RTO

** Additional detail available in the JOA between MISO and PJM in Article IX.

Cross-Border Cost Sharing with PJM (cont.)

- Cross-Border Market Efficiency Project
  - Project costs are allocated to each RTO based on their share of the benefits
  - Each RTO based on the costs allocated to them will evaluate the project against their respective criteria for economic projects. If a project meets the PJM but not MISO criteria the project would not qualify for cross-border cost sharing.
  - Annual Revenue Requirements determined by Attachment CC (similar to Attachment GG and MM) if the project is located in MISO and charged through Schedule 25

** Additional detail available in the JOA between MISO and PJM in Article IX.

Additional Questions:

Contact:
Jeremiah Doner
317-249-5717
jdoner@misoenergy.org

Order 1000 Discussion Local and Regional Planning Requirements

January 25, 2012

MISO

Order 1000 Paragraph 65 - Requirement A1

- Requirement:

  We also clarify that the requirements of this Final Rule are intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule. The requirements of this Final Rule will apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's filing adopting the transmission planning and cost allocation reforms of the pro forma OATT required by this Final Rule. We appreciate that transmission facilities often are subject to continuing evaluation as development schedules and transmission needs change, and that the issuance of this Final Rule is likely to fall in the middle of ongoing planning cycles. **Each region is to determine at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the requirements of this Final Rule.** Our intent here is that this Final Rule not delay current studies being undertaken pursuant to existing regional transmission planning processes or impede progress on implementing existing transmission plans. We direct public utility transmission providers to explain in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule.

- MISO Assessment:

  Action required

Order 1000 Paragraph 65 - Requirement A1

- Three stakeholders commented
- Key takeaways:
  - The tariff should be modified such that projects are only subject to reevaluation until approved by the State commissions.
  - MISO has not explained how it will determine which transmission facilities are subject to the Final Rule.
  - Tariff changes to implement the final rule should be made effective when the compliance filing is made in October 2012.

Order 1000 Paragraph 65 - Requirement A1

- MISO Response:
  - MISO believes this paragraph addresses the issue of setting the effective date of the compliance filing in a manner not to impede ongoing transmission planning processes.
  - MISO does not believe this paragraph is intended to address the generic subject of project reevaluation after approval.
  - The high level proposal attempts to establish a clean break by beginning the implementation of the provisions of the compliance filing with the start of a new planning cycle.
  - As such, MISO would like to slightly modify the wording of the high level proposal as shown in red on the following slide.

Order 1000 Paragraph 65 - Requirement A1

- High Level Proposal:
  1) The Final Rule will apply to projects approved in the first full planning cycle to commence after the effective date of the Commission's order on the compliance filing. ~~receiving Commission approval of the proposal.~~
     1) A typical planning cycle begins on June 1 and ends in December of the following year when the MISO BOD approves the final MTEP for the planning cycle
     2) For example the MTEP 2014 planning cycle begins on June 1 2013.
  2) Projects approved prior to the above planning cycle will not be reevaluated for purposes of the Final Rule.

Order 1000 Paragraph 82 - Requirement A2

- Requirement:

  Requires amending OATT to provide for consideration of transmission needs driven by Public Policy Requirements.

- MISO Assessment:

  Believed to be compliant

Order 1000 Paragraph 82 - Requirement A2

- Three stakeholders commented
- Key takeaways
  - –Only MVPs provide for public policy benefits, thus projects not part of a regional portfolio that have only local public policy benefits are not included.
  - –The restriction in Criterion 1 that MVPs address only "energy policy mandates or laws" that "directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation" is too narrow and does not include all possible public policy needs.

Order 1000 Paragraph 82 - Requirement A2

- MISO Response:
  - –MVPs represent a "project type" that allow for region allocation of the costs of project portfolios with regional benefits.
  - –MVPs are more of a cost allocation mechanism than a planning mechanism to consider public policy needs.
  - –Attachment FF- Section I.A.5 and Module A Section II.1.667b, which were developed and/or revised in conjunction with the MVP tariff filing, provide the mechanism to incorporate public policy needs into the MISO transmission planning process.
  - –Order 1000 Paragraph 214. “We do not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations.. . .”

MISO

Order 1000 Paragraph 82 - Requirement A2

- MISO Response Continued:
  - **Attachment FF - Section I.A.5: Planning Criteria:** The Transmission Provider shall evaluate the system to [address] Transmission Issues in a manner consistent with the ISO Agreement and this Attachment FF.
  - **Module A Definition of Transmission Issue:** A reason to improve, expand or modify the Transmission System. These reasons may be compliance-based, economic-based, or reflect other local needs. Compliance-based reasons reflect the need to comply with all requirements imposed on the Transmission System performance by entities with jurisdiction or authority over all or part of the Transmission System including, but not necessarily limited to, ………. iv) compliance with applicable state and federal laws and v) compliance with applicable regulatory mandates and obligations, including regulatory obligations related to serving load, interconnecting generation and providing transmission service.

MISO

Order 1000 Paragraph 146 - Requirement A3

- Requirement:

  Requires participation in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order 890.

- MISO Assessment:

  Believed to be compliant

Order 1000 Paragraph 146 - Requirement A3

- One stakeholder commented
- Key takeaway
  - Uncertain as to whether or not MISO is compliant. MISO's current process does produce a regional plan, but it is not clear that MISO's current process evaluates alternatives, in consultation with stakeholders, that meet transmission needs more cost effectively than projects proposed in the local planning process.

Order 1000 Paragraph 146 - Requirement A3

- MISO Response:
  - – MISO believes it is fully compliant with this requirement. MISO produces a regional plan each year that complies with the provisions of Order 890.

MISO

Order 1000 Paragraph 148 - Requirements A4 & A5

- Requirement A4:

  Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process.

- Requirement A5:

  When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis.

- MISO Assessment: Believed to be compliant

Order 1000 Paragraph 148 - Requirements A4 & A5

- Three stakeholders commented
- Key takeaways
  – MISO is compliant
  – MISO should modify the tariff to affirmatively identify in each MTEP all alternatives transmission solutions evaluated for each project
  –Requiring contractual commitments on demand-side resources to be eligible as non-transmission alternative solutions may not fully account for demand-side resource solutions available through existing or future MISO energy, ancillary services and capacity markets.
  –Appendix B, Section IX of the Transmission Owners Agreement describes the process used by MISO in coordination with incumbent utility transmission owners to identify alternatives for further study. The language should be expanded to include non-incumbent transmission developers as well.

Order 1000 Paragraph 148 - Requirements A4 & A5

- MISO Response on Alternatives and Non-Incumbent Developers:
  - MISO conducts a thorough and transparent transmission planning process which allows for the study and consideration of alternatives in stakeholder forums such as Subregional Planning Meetings and/or Technical Study Task Forces.
  - These forums ensure the opportunity to propose alternatives and discuss among stakeholders the results of alternatives analysis.
  - The MTEP report is a high level summary of the regional transmission plan and may not include every detail discussed in the stakeholder process.
  - MISO agrees that the obligation to study alternatives as stated in Appendix B of the TOA should apply equally well to both incumbent and non-incumbent transmission developers. This will be addressed under the initiative to comply with Order 1000 requirements related to ROFR.

Order 1000 Paragraph 148 - Requirements A4 & A5

- MISO Response on Demand Side Contractual Commitments:
  - MISO has an obligation to comply with reliability standards.
  - Therefore, the developer of any solution associated with a regional transmission plan must make a good faith effort to implement the solution to ensure compliance with applicable reliability standards.
  - Appendix B - Section VI of the Transmission Owners Agreement obligates the Transmission Owners to make a good faith effort to seek regulatory approval and construct all transmission facilities approved in the regional transmission plan.
  - Since MISO does not engage in integrated resource planning, the consideration of any non-transmission solution in a regional transmission plan must carry with it a firm obligation by the proposed developer.
  - It is important to note that MISO does consider demand response solutions in the long-term planning process with or without a firm obligation.

Order 1000 Paragraph 164 - Requirement A6

- Requirement:

  Define for merchant transmission developers what information and data has to be provided to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region.

- MISO Assessment:

  Action required

- Action Item:

  MISO staff to develop straw proposal and present to PAC for comments and feedback in early 2012. Compliance with this requirement will be coordinated with compliance to address the right-of-first-refusal.

Order 1000 Paragraph 164 - Requirement A6

- One stakeholder commented
- Key takeaway
  - Merchant transmission developers must build and operate transmission projects to the host Transmission Owner's design, engineering, material, construction and operation and maintenance standards.

MISO

Order 1000 Paragraph 164 - Requirement A6

- MISO Response:
  - This requirement will be addressed in conjunction with the Order 1000 requirements related to right-of-first-refusal, and all stakeholder comments will be considered in that process.

Order 1000 Paragraphs 203 and 206 (Requirements A7 and A8)

- Requirement A7 in Paragraph 203:

  Requires amending OATT to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.

- Requirement A8 in Paragraph 206:

  Develop procedures under which public utility transmission providers and stakeholders will identify those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated.

- MISO Assessment:

  Believed to be compliant

Order 1000 Paragraphs 203 and 206 (Requirements A7 and A8)

- Four stakeholders commented
- Key takeaways
  - Procedures are not clearly stated in the tariff or BPMs.
  - More detail is needed in the tariff.
  - Information articulated in BPMs or BOD Planning Principles should be added to the tariff.
  - Further clarification is needed in the tariff on how transmission needs follow from public policy requirements. For example, it is not clear how a public policy requirement relates to a Transmission Issue, how various renewable portfolio standards in states in the MISO region affect development of MVPs, or how changes in RPS standards being take in consideration over time.

MISO

Order 1000 Paragraphs 203 and 206 (Requirements A7 and A8)

- MISO Response on Paragraph 203:
  - –Order 1000 compliance only requires language related to the requirement in paragraph 203 to be in the tariff.
  - –MISO believes that the definition of Transmission Issues in Module A and the statement in Attachment FF that the planning criteria must address Transmission Issues represents a procedure to ensure a regional transmission plan will comply with state and Federal laws as well as regulatory obligations and mandates.

Order 1000 Paragraphs 203 and 206 (Requirements A7 and A8)

- MISO Response on Paragraph 206:
  - –Order 1000 compliance does not appear to require language related to the requirement in paragraph 206 to be in the tariff.
  - –MISO believes that the requirement in paragraph 206 relates to establishing procedures that allow for the analysis to identify specific Transmission Issues related to public policy requirements.
  - –MISO contains procedures within the current Transmission Planning BPM, primarily in Section 4.3 (Short-term Planning) and Section 4.4 (Long-term Planning), that relate to performing analysis to determine, among other things, which public policy requirements require solutions.

Order 1000 Paragraph 209 - Requirement A9

- Requirement:

  Requires public utility transmission providers to post on their websites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

- MISO Assessment:

  Limited action required

MISO

Order 1000 Paragraph 209 - Requirement A9

- High Level Proposal

  Add language to tariff that requires MISO to post on its websites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

Order 1000 Paragraph 209 - Requirement A9

- Two stakeholders commented
- Key takeaways
  - Agree that MISO is not yet compliant
  - No comments on high level proposal

Order 1000 Paragraph 209 - Requirement A9

- MISO Response:
  - – MISO will pursue the high level proposal and will work with stakeholders to implement by the effective date of the compliance filing.

Mckinnie, Adam

From: Matthew H. Tackett [mtackett@misoenergy.org]
Sent: Thursday, January 26, 2012 7:38 AM
To: Mckinnie, Adam; Laura Rauch
Subject: RE: matt tacket's e mail address?

Adam.

You are correct. If the effective date of the order is prior to June 1, 2013, then MTEP14, which typically begins June 1, 2013 and extends through December 2014, would be the first planning cycle impacted by Order 1000 provisions.

Let me know if you have any other questions.

Thanks,

Matt

From: Adam McKinnie
Sent: Wednesday, January 25, 2012 4:49 PM
To: Laura Rauch
Cc: Matthew H. Tackett
Subject: RE: matt tacket's e mail address?

Thanks Laura!

Matt – quick question, wanted to make sure I got it down correctly over the phone – did you say the FERC Order 1000 impacts would affect MTEP14 as the first MTEP? Or was it MTEP13?

If the effective date of the FERC order after compliance filing for non cost allocation requirements is between October 2012 and June 2013, and June 2013 is the start of the MTEP14 cycle, that would mean MTEP14. Is that the right way to think about it?

Oh, the perils of trying to figure things out over the phone.

From: Laura Rauch [mailto:LRauch@misoenergy.org]
Sent: Wednesday, January 25, 2012 3:46 PM
To: Mckinnie, Adam
Cc: Matthew H. Tackett
Subject: RE: matt tacket's e mail address?

Tackett with two 't's – also copied on this e-mail for your convenience.

Laura Rauch, P.E.
317-249-5853
MISO

From: Adam McKinnie
Sent: Wednesday, January 25, 2012 4:45 PM

To: Laura Rauch
Subject: matt tacket's e mail address?

Want to double check a statement he made, want to make sure I'm spelling his last name right.