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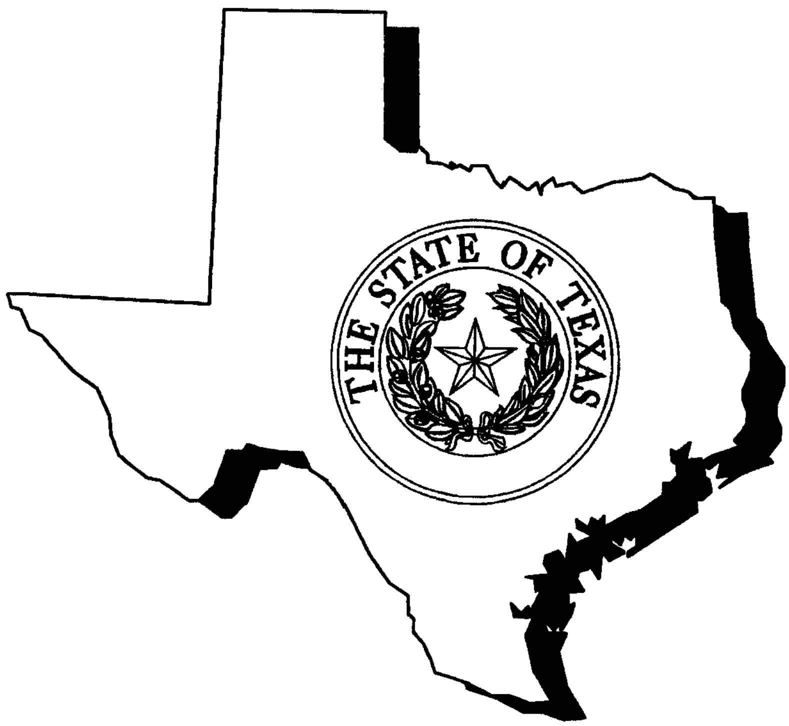
SOAH DOCKET NO. 473-12-6206
DOCKET NO. 40346

APPLICATION OF ENTERGY TEXAS, INC. FOR APPROVAL TO TRANSFER OPERATIONAL CONTROL OF ITS TRANSMISSION ASSETS TO THE MISO RTO	§ § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**



DIRECT TESTIMONY OF

CHRIS ROELSE, P.E.

INFRASTRUCTURE & RELIABILITY DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

July 16, 2012

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WORKPAPERS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, occupation and business address.

A. My name is Chris Roelse. I am employed by the Public Utility Commission of Texas ("PUC" or "the Commission") as an Electric Utility Engineer in the Infrastructure and Reliability Division. My business address is 1701 N. Congress Avenue, Austin, TX 78711-3326.

Q. Please briefly outline your educational and professional background.

A. I have a Bachelor of Science Degree in Mechanical Engineering. My professional experience includes manufacturing of semiconductor capital equipment, design, troubleshooting, documentation, process and product improvements. I have been with the Commission for over three years and have experience in evaluating and making recommendations on Certificates of Convenience and Necessity (CCN) and rate cases, and participating in annual transmission planning presentations by regulated utilities. A more detailed resume is provided in Exhibit CR-1.

Q. Are you a registered professional engineer?

A. Yes, License Number 110241 in the State of Texas.

Q. Have you filed testimony at the Commission?

A. A list of dockets in which I have filed testimony is provided in Exhibit CR-2.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to consider whether the transfer of operational control of Entergy Texas, Inc. (ETI) transmission assets to the Midwest Independent Transmission System Operator, Inc. (MISO) Regional Transmission Organization (RTO) is in the public interest, and in doing so, consider whether such a transaction adversely affects the reliability of service, availability of service, or cost of service. In particular, I will address issues 2, 3, 4, 7, 7a, 7b, 7c, 7d, 9, 9a, 9b, 14, 15, 16, 18, and 19 in the Preliminary Order, which was filed in this docket on May 22, 2012.

Q. What information have you relied upon in your analysis and evaluation of the application?

A. I have relied upon my review and analysis of the Application and its attachments.[1] I relied upon the direct testimonies and supplemental direct testimonies filed in this proceeding by or on behalf of ETI and the intervenors, as well as responses to requests for information (RFIs) filed by parties to this proceeding.

III. RECOMMENDATIONS AND CONCLUSIONS

Q. What regulations have you referred to in making your evaluation and arriving at your conclusions and recommendations?

A. PURA §§39.915(a) and (b) and 39.457(l) and (m). The relevant language in these sections is nearly identical.

Sec. 39.915. CONSIDERATION AND APPROVAL OF CERTAIN TRANSACTIONS.

(a) To protect retail customers in this state, and to ensure the continuation of cost-effective energy efficiency measures and delivery systems, notwithstanding any other provisions of this title, an electric utility or transmission and distribution utility must report to and obtain approval of the commission before closing any transaction in which:

[1] *Application of Entergy Texas, Inc. for Approval to Transfer Operational Control of Its Transmission Assets to the MISO RTO*, Docket No. 40346, Application at 2 (April 30,2012) (Application).

> (1) The electric utility or transmission and distribution utility will be merged or consolidated with another electric utility or transmission and distribution utility:
> (2) At least 50 percent of the stock of the electric utility or transmission and distribution utility will be transferred or sold; or
> (3) A controlling interest or operational control of the electric utility or transmission and distribution utility will be transferred.
>
> (b) The commission shall approve a transaction under Subsection (a) if the commission finds that the transaction is in the public interest. In making its determination, the commission shall consider whether the transaction will adversely affect the reliability of service, availability of service, or cost of service of the electric utility or transmission and distribution utility. The commission shall make the determination concerning a transaction under this subsection not later than the 180[th] day after the date the commission receives the relevant report. If the commission has not made a determination before the 181[st] day after that date, the transaction is considered approved.

Q. Please summarize the conclusion that you have reached as a result of your analysis.

A. I have reached the following conclusions concerning the transfer of operational control of ETI's transmission assets to the MISO RTO:

1. It does not adversely affect the reliability of transmission service.
2. It does not adversely affect the availability of transmission service.
3. When considering the affects to the reliability and availability of transmission service only, it is in the public interest.
4. Transmission costs are addressed in the direct testimonies of Shawn Carraher and Julia Frayer on behalf of Commission Staff.
5. I recommend the conditions and limitations discussed below.

Q. What conditions or limitations, if any, do you conclude should be placed on the transfer of operational control of ETI's transmission assets to the MISO RTO or to ensure that a transfer, if approved, proceeds in an appropriate manner?

A. In my opinion, the transfer of operational control of ETI's transmission assets to the MISO RTO should be dependent upon the regulatory approval of Entergy Arkansas, Inc. (EAI) and the other Entergy Operating Companies' transfer to the MISO RTO. Without EAI joining MISO, the physical interconnection requirement between MISO and the other Entergy Operating Companies will not be satisfied. Additionally, ETI's application and all the cost-benefit analyses and studies that have been conducted by Entergy are based on EAI and the other Operating Companies transferring to MISO.

IV. STAFF ANALYSIS

Q. Please describe the transmission service that is provided over Entergy's transmission system today.

A. Transmission service across the Entergy transmission system currently is pursuant to the terms and conditions of the Entergy Open Access Transmission Tariff (OATT).[2] The Entergy energy delivery function plans, engineers, constructs, and operates 16,500 miles of 69kV to 500kV transmission lines on behalf of the Operating Companies.[3] The Independent Coordinator of Transmission (ICT) for the Entergy transmission system is the reliability coordinator for grid security and stability and administers Entergy's OATT Tariff and planning functions.[4] The Operating Companies use each other's transmission facilities under provisions of Service Schedule MSS-2 (Transmission Equalization) of the System Agreement.[5] The transmission service is based on a system of "physical rights", where transmission reservations are provided to customers on a "first come, first served"

[2] Direct Testimony of Michael M. Schnitzer at 19:4-5.
[3] http://www.entergy.com/energydelivery/default.aspx
[4] http://www.entergy.com/energydelivery/transmission_system_facts.aspx
[5] Direct Testimony of Michael M. Schnitzer at 19:16-18.

basis, which does not take into account the economics of the parties requesting transmission service.[6] Granting transmission service for one customer's use of a high cost resource could prevent a subsequent request by another transmission customer to make deliveries from a lower cost resource.[7] The result is transmission congestion and the denial of transmission service in the days or months ahead of actual operations.[8] Congestion on the transmission system is managed in real-time primarily through the North American Electric Reliability Corporation's (NERC) Transmission Loading Relief (TLR) procedures.[9] Under these procedures, transmission services with equal curtailment priority that are affecting congested facilities are curtailed on a pro rata basis.[10] As a result of the curtailment, the affected party must use alternative, more expensive resources to serve its load or otherwise meet its obligations. Therefore, TLRs have an economic effect on the party whose transmission transaction is curtailed; however, the TLRs themselves do not take economics into account. The Entergy Operating Companies have recognized the shortcomings of the current *pro forma* OATT and have sought to implement a more efficient method of granting transmission service on the Entergy Transmission System.[11] A significant step was the implementation of the current ICT arrangement which operates the Entergy Transmission System, is the reliability coordinator, produces regional planning assessments, and oversees the operation of an enhanced weekly procurement process for obtaining competitive energy supply.

[6] *Id.* at 20:7-10.
[7] *Id.* at 20:12-15.
[8] *Id.* at 21:15-17.
[9] *Id.* at 21:1-3.
[10] *Id.* at 21:4-7.
[11] *Id.* at 6:12-17.

Q. Please discuss the concerns that led to the development of the ICT.

A. Since 1998, over 17,000 MW of additional merchant generation interconnected to the Entergy transmission system, which already had connected a regulated generation fleet of about 25,000 MW.[12] In 2003, The Entergy Operating Companies had just over 20,000 MW of total peak load.[13] This situation where the amount of generating capacity significantly exceeded (and continues to exceed) peak load, is a reason for issues on the Entergy transmission system that have not been present or as critical elsewhere, and created concerns about independence and transparency in the provision of transmission service.[14] The Operating Companies' efforts initially focused on creating an independent transmission company that would own and operate the Entergy transmission system, but in response to comments on that proposal and FERC's policy guidance, the Operating Companies focused on establishing a joint RTO with SPP, but that proposal was rejected by FERC on July 12, 2001.[15] FERC ordered the Entergy Operating Companies to explore a broader RTO in the Southeast.[16] The Operating Companies' attempted to establish the SeTrans RTO, but regulators in the Southeast region raised concerns, and FERC issued an order terminating proceedings related to the SeTrans RTO on July 15, 2005.[17] The ICT proposal, which was first filed even before SeTrans RTO efforts were terminated, was developed to establish greater independence and transparency in the operation of the Entergy transmission system and to address concerns that were specific to the Entergy Region.[18] On April 26, 2006 FERC approved the arrangement under

[12] *Id.* at 24:18-21 and 25:1.
[13] *Id.* at 25:1-2.
[14] *Id.* at 25:2-7.
[15] *Id.* at 23:9-15.
[16] *Id.* at 23:15-16.
[17] *Id.* at 23:17-19 and 24:1-7.
[18] *Id.* at 24:8-12.

which the Southwest Power Pool (SPP) functions as the ICT for the Entergy Transmission System.[19]

Q. Please describe the role of the ICT.

A. The ICT's responsibilities include the authority to grant or deny requests for transmission service under the OATT, calculate available flowgate capability, administer the Entergy Open Access Same-Time Information System (OASIS), and perform an enhanced planning function.[20] The ICT also functions as the reliability coordinator for the Entergy System and oversees operation of the Weekly Procurement Process (WPP).[21] The WPP allows merchant generators to competitively bid to provide power to meet Entergy's system requirements for the upcoming week and determines whether accepting some or all of the bids, taking into account the expected configuration and limits on the transmission system, will produce a more economic mix of resources than the Operating Companies' existing resources.[22]

Q. How is transmission congestion managed in MISO's Day 2 Market?

A. The central concept underlying Day 2 Markets is the recognition that when there is congestion on the transmission system, the incremental cost of energy will not be the same at each location. That incremental cost at a particular point on the grid is known as the Locational Marginal Price (LMP), which is used to manage congestion in a Day 2 Market. LMPs represent the cost to serve a hypothetical additional megawatt of load in

[19] Evaluation Report at 33.
[20] *Id.* at 33-34.
[21] Direct Testimony of Michael M. Schnitzer at 22:14-16.
[22] http://www.spp.org/publications/Entergy-SPP_WPP_Process_Launches.pdf

an hour at a specific location, using the lowest offer cost of all available generation while observing all transmission and system reliability limits. In LMP-based markets, an LMP is calculated at every point, or "node," on the transmission system for every hour of every day. The calculation of LMPs is partially based on the transmission system characteristics, including the endpoints of each transmission link, the electrical characteristics of each link, and the reliability constraints that must be met. The calculation of LMPs is also based on supply offers and schedules as well as demand schedules. When congestion arises on a transmission grid, the least cost supply of energy resources cannot be used to serve load in the affected areas, and more expensive resources must be dispatched. In a Day 2 Market, this occurs ahead of time through the RTO day-ahead market and in real-time in the real-time energy markets. LMPs provide market-based price signals, taking congestion into consideration, that are used to determine the next lowest cost mix of resources that can be used to serve the affected load. The least-cost supply of electricity is delivered while respecting the physical limitation of the transmission grid. In the day-ahead market, Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR) get issued based on transmission capacity and as a means to provide a financial hedging mechanism to load serving entities and other market participants against congestion charges. An ARR is a market participant's entitlement to a portion of the revenue generated in FTR auctions. An FTR gives the holder a right to a payment (or an obligation to pay a charge) based on the difference between day-ahead LMPs at the points of withdrawal and injection of energy.

Q. What reliability benefits to ETI's transmission system does Entergy expect from a transfer of operational control to the MISO RTO?

A. ETI witness Mr. Michael Schnitzer states on pages 60 and 61 of his direct testimony that MISO is required to meet the minimum NERC standards for maintaining reliability. Mr. Schnitzer states that in MISO's Day 2 Market, ETI will have access to more generation that will be available in real-time and without the need to schedule a purchase and arrange for transmission service. But, there will be congestion on the transmission system, just as there is congestion on the transmission system today, and as a result there will be costs due to the congestion. Please see the direct testimony of Shawn Carraher concerning ARRs and FTRs for further discussion on this issue. Mr. Schnitzer maintains that the increased access to more generation in real-time will help to ensure that there is a set of generators on-line and available at the appropriate times to manage the power system within safe parameters. He states that TLRs often require long periods of time to bring transmission within required operational limits, and sometimes require several attempts. When transmission congestion arises in an LMP-based market, a new dispatch is determined on a five-minute interval, which should increase reliability.[23] Furthermore, he states that MISO's Value Proposition discusses many of the reliability benefits provided by MISO, including (a) an enhanced transmission system monitoring tool that can evaluate over 7,000 contingencies every five minutes, (b) managing congestion in real time with LMP-based dispatch, rather than solely through the use of TLRs, (c) improved back-up capability to mitigate the effects of significant events or disturbances, and (d) enhanced review of region-wide operational performance.[24]

[23] Direct Testimony of Michael M. Schnitzer at 60:19-21 and 61:1.
[24] *Id.* at 61:1-8.

Q. Does Entergy expect there to be reliability benefits to ETI if it were to transfer operational control to the SPP RTO?

A. The SPP RTO is also required to meet the minimum NERC standards for maintaining the reliability of the grid, since all registered transmission operator and balancing authorities must meet this requirement. Many of the reliability benefits that follow from joining an RTO arise through participation in a Day 2 Market; however, SPP does not currently have a Day 2 Market in place. In April 2011, the SPP Board of Directors approved the final protocols defining the market design that would be implemented, but SPP does not anticipate implementing a Day 2 Market until March 2014.[25] SPP states that they have had the benefit of knowledge and lessons learned from other market implementation efforts to help them establish a solid implementation plan and fully expect to implement their Day 2 Market on time and within budget.[26] However, Entergy states that the costs and benefits are substantially less certain and entail greater risk with the SPP RTO option, whereas MISO's Day 2 Market is about eight years ahead of SPP's in its development and evolution and has a proven track record.[27]

Q. Are there other benefits to joining the SPP RTO?

A. Yes. There are currently 45 interconnections between SPP members and the Entergy Operating Companies, of which nine are interconnections with SPP RTO market

[25] Application, Exhibit A, Attachment B (Evaluation Report) at 23.
[26] Direct Testimony of Carl A. Monroe on behalf of SPP at 54:15-16 and 55:2-3 (July 6, 2012).
[27] Application, Exhibit A, Attachment B (Evaluation Report) at 23.

members.[28] It can be reasonably assumed that there will be one or more interconnections in service at any point in time between SPP RTO market participants and Entergy because of the multiple interconnections, which will likely not be the case between MISO members and Entergy since there is only a single 1000 MW interconnection.

Q. Please describe the Entergy Transmission Planning Standards used today.

A. The Entergy Local Planning Criteria[29] is used in performing planning studies for the Entergy transmission system, and is used to gauge the system's security and adequacy and is based on NERC's reliability standards and other applicable regulatory standards.[30] The Entergy Local Planning Criteria uses more stringent planning standards for load pockets in order to maintain adequate reliability of service.[31] A load pocket it is an area with limited transmission ties interconnecting it with adjoining areas, and therefore must be served at least in part by local generation. Load pocket areas on the Entergy Transmission System are planned to withstand the loss of both (a) the largest transmission facility in the area, and (b) the largest generating facility committed inside the area.[32] The application of these criteria is more stringent than those currently required by the NERC reliability standards. Entergy's Western Region, where ETI partially resides, is an example of a load pocket where these more stringent criteria are used.

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[28] ETI response to Staff RFI 7-3a. ETI noted 41 interconnections in its application, but noted that there are three new interconnections and a tie that is normally open in the response, accounting for the four additional interconnections.

[29] Viewable at http://www.oatioasis.com/EES/EESdocs/transmission_local_planning_criteria.pdf

[30] Direct Testimony of Richard C. Riley at 65:16-16-20.

[31] *Id.* at 66:10-13.

[32] *Id.* at 66:14-18.

Q. Please describe MISO's Transmission Planning Standards that would apply if ETI were to transfer operational control of their transmission assets.

A. MISO's planning process applies NERC standards to all of their members, except to the extent that a member's local planning standard is more stringent than a NERC standard, and in that case, the more stringent local standard applies to that member.[33] Mr. Riley states that the Operating Companies' current transmission planning reliability standards thus comply with those that will apply under MISO membership.[34]

Q. In your opinion, would the transfer of operational control of ETI's transmission assets to the MISO RTO adversely affect the reliability of transmission service?

A. In my opinion, the transfer of operational control of ETI's transmission assets to the MISO RTO would not adversely affect the reliability of transmission service. An RTO will provide reliability benefits by providing a real-time market-based congestion management approach, an enhanced transmission monitoring tool, and provide an enhanced view of region-wide performance.

Q. Does Entergy expect the transfer of operational control of ETI's transmission assets to the MISO RTO to provide benefits regarding the availability of transmission service, and if so, what are they?

A. Yes. Mr. Schnitzer explains on page 63 of his direct testimony that the physical transmission rights under the pro forma OATT and the TLR process do not seek to obtain

[33] *Id.* at 65:6-9.
[34] *Id.* at 65:10-12.

the most efficient use of available transmission capacity in terms of the economics of granting service or in selecting service to be curtailed. MISO's Day 2 Market congestion management approach results in more efficient utilization of available transmission capacity by taking into account the relative cost of generation, and using the lowest overall cost re-dispatch options to manage congestion. In a Day 2 Market, the availability of transmission service is not dependent on transmission service requests or the resulting physical rights to the system, as is the case under the OATT.

Q. In your opinion, would the transfer of operational control of ETI's transmission assets to the MISO RTO adversely affect the availability of transmission service?

A. In my opinion, there has been no evidence provided that shows that the transfer of operational control of ETI's transmission assets to the MISO RTO would adversely affect the availability of transmission service. A Day 2 RTO market approach of calculating electricity prices at thousands of pricing points, or nodes on the electricity grid should create greater transparency of congestion and congestion costs. The improved price transparency should result in more efficient utilization of available transmission capacity.

Q. Please explain the Joint Operating Agreement (JOA) and how it would address compensation regarding loop flows?

A. The JOA allocates firm flow rights across critical flowgates.[35] Under the JOA, MISO and SPP are each entitled to use, without compensation, their respective shares of those flowgates.[36] The JOA does not require compensation when an RTO's use exceeds its share of an allocated flowgate and the flowgate is not congested.[37] The only circumstance providing compensation to the affected RTO is when an RTO uses more than its share of an allocated flowgate and the flowgate is congested.[38] FERC has made it clear that if the Entergy Region joins MISO, then issues related to the effects on the SPP member systems from market flows between MISO and the Entergy Region will be addressed within the context of the JOA.[39] However, the changes to the JOA and the effects of the changes are not known.

Q. What are the loop-flow impacts when comparing the Join MISO and Join SPP options?

A. SPP retained Charles Rivers Associates (CRA) to perform an assessment of the potential change in energy flows on the SPP transmission system assuming the Entergy Operating Companies and Cleco Power integrate into MISO. The assessment estimated the amount of additional congestion on flowgates and estimated the amount of additional generation redispatch that would be required to manage the congestion on flowgates under a market-to-market congestion management procedure.[40] However, a market-to-market congestion

[35] Supplemental Direct Testimony of Michael M. Schnitzer at 13:1-2. Flowgates are defined as designated points on the transmission system through which reliability coordinators use mechanisms to calculate the power flow from a seller to a buyer that crosses one or more balancing authority boundaries.
[36] Supplemental Direct Testimony of Michael M. Schnitzer at 13:2-3 (June 1, 2012).
[37] *Id.* at 13:3-5.
[38] *Id.* at 13:5-8.
[39] *Id.* at 13:9-12.
[40] Direct Testimony of Ralph L. Luciani on behalf of SPP at 5:4-8 (July 6, 2012).

management procedure under the JOA is not currently in place but is being discussed between SPP and MISO.[41] Such a procedure could not be in place for at least one year after SPP's Day 2 market is implemented.[42] Using an average redispatch cost to relieve congestion, the results show there would be compensation due to SPP of roughly $6.5 million/year (based on 2013 transmission topology).[43] The assessment estimates a compensation amount of $3.5 million/year (based on 2013 transmission topology) would be due to SPP under the JOA between MISO and SPP based on flowgate specific shadow prices.[44] In rebuttal testimony of Mr. Schnitzer provided on behalf of EAI, he maintains the $3.5 million/year figure is more relevant since it uses flowgate specific shadow prices associated with the constrained flowgates.[45] However, he believes the $3.5 million/year compensation is over-stated because of approved projects that are in EAI's construction plan that are expected to be in service in the summer of 2014 and can reasonably be expected to reduce congestion on flowgates and increase MISO's allocated share of flowgate capacity.[46] Southwestern Electric Power Company (SWEPCO), which is in the SPP footprint, expects higher generation redispatch costs due to the additional loop flow and congestion that would result from ETI joining MISO.[47] SWEPCO estimates its cost impact of additional loop flow and congestion on its transmission system from ETI transferring to MISO to be approximately $119,000/year based on 2013 transmission

[41] Rebuttal Testimony of Michael M. Schnitzer, Energy Arkansas, Inc. (Docket No. 10-011-U) at 12:13-15. (ETI response to Staff RFI 6-18 (June 19, 2012).).
[42] Direct Testimony of Ralph L. Luciani on behalf of SPP at 6:8-10.
[43] *Id.* at 12:7-8.
[44] *Id.* at 12:12-14. Shadow price is a measure of the economic value created by relieving the constraint.
[45] Rebuttal Testimony of Michael M. Schnitzer, Energy Arkansas, Inc. (Docket No. 10-011-U) at 22:15-19.
[46] *Id.* at 23:8-16.
[47] Direct Testimony of Kip M. Fox on behalf of SWEPCO at 10:8-9 (July 6, 2012).

topology, with approximately $56,000/year of these being allocated to SWEPCO Texas ratepayers.[48]

Q. Is there sufficient transmission capacity to and in Entergy to enable any Texas customer on the Entergy system to enjoy the economic and reliability benefits of MISO's wholesale market?

A. As part of Entergy's regular transmission planning process, and included on Page 7 of Mr. Riley's supplemental Direct Testimony, ETI identified several transmission reliability projects that are planned to be in service prior to the proposed transfer to MISO. The studies by Charles River Associates (CRA) in its Cost Benefit Analyses (CBAs) and by the Entergy Operating Companies in their May 12, 2011 *Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO* (Evaluation Report) were based on having these transmission facilities in service during the timeframes of the studies.[49] The benefits of RTO membership identified in the results of those studies are consistent with the transmission topology as reflected in the models used in the studies. Therefore, the transmission capacity to and within the ETI transmission system is, or is expected to be, sufficient to provide the economic benefits identified in the studies.[50] MISO witness Jennifer Curran explained that additional transmission is not necessary to integrate the Entergy Operating Companies into MISO.[51] MISO has stated that they have not conducted any preliminary studies of reliability-driven transmission projects or

[48] *Id.* at 10:16-21.
[49] Supplemental Direct Testimony of Richard C. Riley at 2:12-18 (June 1, 2012).
[50] *Id.* at 2:11-17.
[51] Direct Testimony of Jennifer Curran on behalf of MISO at 23:17 (July 6, 2012).

transmission reinforcements that need to be done for Entergy to join MISO, and maintain that such studies are not needed.[52] The exact effects on Entergy's transmission system are unknown until Entergy actually transfers to MISO, at which time it could become more apparent that additional transmission projects or upgrades are needed in the Entergy region. The possibility of such transmission projects being needed should be considered as part of the cost-benefit analysis, as referred to in the direct testimony of Staff Witness Shawn Carraher.

Q. What are the economic costs associated with existing transmission constraints on the Entergy system?

A. ETI states that there has been no analysis performed to quantify the historical estimated costs of transmission constraints based on TLRs.[53]

Q. Have there been any studies conducted to analyze existing transmission constraints in the ETI region?

A. Mr. Riley discusses two studies that have been conducted on pages 4-6 of his supplemental direct testimony. These studies were conducted to analyze existing constraints in the ETI region, and were not analyzed under conditions of ETI being part of an RTO. First, the Minimizing Bulk Power Costs study was prepared by ABB, Inc. at the request of the Entergy Regional State Committee (E-RSC). This study analyzed the West of the Atchafalaya Basin (WOTAB) Region, which is partially within Texas and partially within Louisiana, and the Western Region, which is entirely within Texas. For

[52] MISO response to Staff RFI 5-1 and 5-2 (July 12, 2012).
[53] ETI response to Staff RFI 5-5 (June 18, 2012).

the WOTAB Region, no economically beneficial projects were identified in the 2013 model. Some large transmission projects were identified to permit the displacement of over 3,100 MW of legacy generating capacity in 2022, but resulted in expected benefits to be less than half the cost.[54] Smaller transmission portfolios were identified that warrant further study for the 2022 model of the WOTAB Region, and the Company is committed to working with the applicable parties on such further analysis. No potential economic projects were identified in the models for the Western Region.[55] The study concluded that for the particular transmission portfolios studied in the Western Region, the capital costs of these transmission upgrades exceeded the benefits. Second, the ICT performs the ICT Strategic Transmission Expansion Plan (ISTEP) each year, and as part of this process, the ICT performed screening studies of five potentially economical transmission projects that are selected through voting by stakeholders.[56] Each year, the Entergy Operating Companies receive the ISTEP results and perform more detailed studies of those projects that appear to be of greater economic benefit to the Operating Companies' customers. To date, this process has identified one project in Arkansas that was not already in Entergy's Construction Plan.[57]

Q. Does ETI have any plans to relieve any known or anticipated transmission constraints before the effective date that it joins MISO, and if so, what are those plans and what are the costs?

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[54] Supplemental Direct Testimony of Richard C. Riley at 4:15-20 and 5:1-11.
[55] *Id.* at 5:12-13.
[56] *Id.* at 6:3-6.
[57] *Id.* at 6:10-12.

A. As stated above, ETI identified twelve transmission upgrade projects they plan to have in service before their proposed integration into MISO; however, these projects were identified as part of their regular planning process and are not upgrades needed to integrate into MISO.[58] ETI states that congestion relief has not been listed as the primary driver for these projects, but maintains that they may result in relieving congestion because the project may increase the capacity of the limiting element of a commonly invoked flowgate or may result in eliminating the contingent element of a commonly invoked flowgate.[59] Therefore, it is not known for certain whether these projects will provide any congestion relief. Estimated costs for these projects have been included as a confidential workpaper to my testimony.[60] If ETI joins MISO, ETI does not believe additional transmission upgrades or improvements will be required that would not otherwise be needed in order to meet MISO reliability standards.[61] As explained previously, MISO has stated that they have not conducted any preliminary studies of reliability-driven transmission projects or transmission reinforcements that need to be done for Entergy to join MISO, and maintain that such studies are not needed. However, the risk of additional transmission being needed does not fall on ETI, but rather on the ratepayers. Ultimately, if additional transmission is needed as a result of transferring to MISO, the Commission should determine whether it was foreseeable that the particular project is needed and whether ETI should bear any financial responsibility in any future proceeding to consider cost recovery for the project.

[58] Supplemental Direct Testimony of Richard C. Riley at 6 and 7.
[59] ETI Response to Staff RFI 6-6 (June 18, 2012).
[60] Entergy confidential response to Staff RFI 3-21 (June 11, 2012).
[61] Direct Testimony of Richard C. Riley at 67:3-5.

Q. Is ETI's participation in MISO dependent on Entergy Arkansas, Inc.'s (EAI) or any other Entergy operating company's participation in MISO?

A. ETI states that it would be technically possible for the other Operating Companies to join MISO if EAI does not join MISO, but several issues would need to be addressed. One issue discussed is that MISO's Transmission Owners Agreement (TOA) requires that a new transmission owning member own or control facilities that are physically interconnected with those of an existing MISO Transmission Owner.[62] This interconnection requirement is satisfied if EAI joins MISO, since EAI is interconnected with Ameren, through a 1,000 MW transmission path under the Interchange Agreement among EAI, Ameren and Associated Electric Cooperative, Inc.[63] If EAI were not to join MISO, this interconnection requirement could possibly be waived by the MISO Board if it results in significant net benefits to MISO and its members.[64] If EAI does not join MISO, this waiver would be required for any of the other Operating Companies to join MISO.[65] Additionally, because all six Operating Companies have proposed to join MISO, scenarios in which some of the Operating Companies were to join MISO and others do not, and the implications of such scenarios on contract paths between the Entergy Operating Companies (except EAI) and MISO have not been analyzed.[66] Also, ETI has stated that a cost-benefit analysis has not been developed that doesn't include EAI joining MISO.[67] Lastly, in the supplemental direct testimony of Mr. Schnitzer he states that because of the joint dispatch provisions under the Entergy System Agreement, all Operating Companies participating in the System Agreement must integrate into

[62] Direct Testimony of Michael M. Schnitzer at 15:26-29.
[63] Evaluation Report at 75-76.
[64] Direct Testimony of Michael M. Schnitzer at 15:29 and 16:1-2.
[65] *Id.* at 16:2-3.
[66] *Id.* at 14:17-19 and 15:1-2.
[67] ETI response to TIEC RFI 1-13 (June 18, 2012).

MISO (or any RTO) or none will be able to integrate."[68] In my opinion, because of the reasons discussed above, ETI's participation in MISO is dependent on EAI's participation as well as the other Operating Companies participation in MISO.

Q. If EAI does not receive approval from the Arkansas Public Service Commission to join MISO, is there an adequate alternate contract path for Entergy to participate in MISO?

A. Entergy has not identified an alternate contract path if EAI does not join MISO. Mr. Schnitzer stated on page 14 of his supplemental direct testimony that Entergy has not attempted to identify possible alternative contract paths for ETI to integrate into MISO in the event EAI does not integrate into MISO.[69] ETI will be taking a risk in joining MISO without EAI also joining since the 1000 MW contract path between MISO and the other Operating Companies would not exist and since a cost-benefit analysis has not been developed that doesn't include EAI joining MISO.

Q. If the Commission denies ETI's proposed transaction, but one or more of the other Entergy Operating Companies become participants in MISO, what would the effects be, if any, on ETI's reliability and availability of service?

A. Mr. Schnitzer addressed a similar question on page 15 of his supplemental direct testimony; however, he identified no reliability or availability of service effects in such a scenario. He stated that all Operating Companies participating in the system agreement

[68] Supplemental Direct Testimony of Michael M. Schnitzer at 15: 14-18.
[69] *Id.* at 14:11-13.

must all integrate to MISO, or none will be able to integrate, because of the joint dispatch provisions in the agreement.[70] All the cost-benefit analyses were based on EAI and all the other Operating Companies moving to MISO, and ETI has not studied the scenario of whether one or more of the Operating Companies do not move to MISO. When EAI terminates its participation in the System Agreement on December 19, 2013, the current joint commitment and dispatch that includes all six Operating Companies will change.

Q. Is there a better alternative than transferring operational control of Entergy's transmission assets to the MISO RTO?

A. Besides continuing operations under the Status Quo arrangement (the ITC arrangement), there have been two alternatives considered and studied; transfer to the MISO RTO or transfer to the SPP RTO. There have been no specific adverse impacts to the reliability or availability of transmission service identified for either of these alternatives. In my opinion, the transfer of operational control to the MISO RTO is in the public interest with regards to reliability and availability of service.

Q. Does this conclude your testimony?

A. Yes.

[70] *Id.* at 15:14-17.

Exhibit CR-1

Statement of Qualifications
Chris Roelse

I received a Bachelor of Science in Mechanical Engineering from the University of Texas (UT) at Austin.

In 1995, I joined Applied Materials (Austin, Texas) as a Manufacturing Technologist. I was production team leader for the manufacturing of semiconductor capital equipment. I was responsible for meeting production schedules, manufacturing new products, implementing process improvements, and training new employees. In 1997, I took a Mechanical Engineering position where I was responsible for quoting, designing, testing, and documenting customer requested non-standard designs into the product. In 1999, I took a position as Final Test Engineering Technician where I was responsible for testing and troubleshooting multi-million dollar equipment prior to being shipped to the customer. In 2001, I transferred into a Manufacturing Engineering position where I was responsible for transitioning new products from pilot manufacturing to volume production. Responsibilities included troubleshooting, engineering changes, product and process documentation, and cost reduction projects.

In 2005, I joined Accretech, USA (Austin, Texas) as a Manufacturing Engineer where I was responsible for the manufacturing of a new product in the semiconductor capital equipment industry. My responsibilities included manufacturing processes, material acquisition, outsourcing, product/process documentation, troubleshooting, engineering projects, and compliance with safety and industry standards. I was promoted to Manufacturing Engineering Manager becoming responsible for engineers on multiple product lines.

In January 2009, I started my employment with the Commission as an Engineering Specialist.

I am a licensed professional engineer in the State of Texas (License No. 110241).

Exhibit CR-2

List of Dockets Containing Testimony of Chris Roelse

PUC Docket Number	Description
37464	Application of Oncor Electric Delivery Company, LLC to Amend its Certificate of Convenience and Necessity for a Proposed CREZ 345-kV Transmission Line in Brown, Mills, Lampasas, McCulloch and San Saba Counties.
36995	Application of Oncor Electric Delivery Company, LLC to Amend a Certificate of Convenience and Necessity for a Proposed Transmission Line within Bell, Falls, Milam, and Robertson Counties.
38230	Application of Lone Star Transmission, LLC for a Certificate of Convenience and Necessity for the Central A to Central C to Sam Switch/Navarro Proposed CREZ Transmission Line
38435	Application of Cross Texas Transmission, LLC for a Certificate of Convenience and Necessity for the Silverton to Tesla 345-kV CREZ Transmission Line in Briscoe, Childress, Cottle, Floyd, Hall, and Motley Counties.
38562	Application of Electric Transmission Texas LLC for a Certificate of Convenience and Necessity for the Riley to Edith Clarke to Cottonwood 345-kV CREZ Transmission Line In Wilbarger, Hardeman, Foard, Knox, Cottle, King, Motley, and Dickens Counties.
38750	Application of Sharyland Utilities, L.P. for a Certificate of Convenience and Necessity for the Hereford to Nazareth to Silverton 345-kV CREZ Transmission Line in Briscoe, Castro, Deaf Smith, Randall, and Swisher Counties.

Exhibit CR-2

List of Dockets Containing Testimony of Chris Roelse

39479	Application of LCRA Transmission Services Corporation to Amend a Certificate of Convenience and Necessity for the Proposed Cushman to Highway 123 138-kV Transmission Line in Guadalupe County.
39896	Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs
40020	Application of Lone Star Transmission, LLC for Authority to Establish Interim and Final Rates and Tariffs

WORKPAPERS

Entergy.
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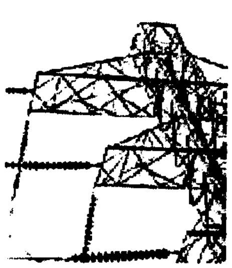
Entergy's Energy Delivery Function

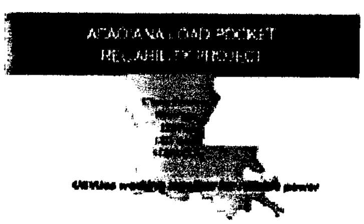
- Regional Transmission Organization
- Entergy to Divest and Merge Electric Transmission Business Into ITC Holdings, Creating Industry Leading Electric Transmission Company



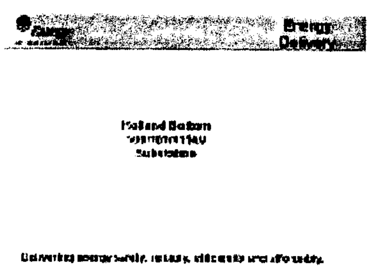
Entergy's energy delivery system moves high voltage bulk electric power across an interconnected grid of wires and substations.

The Entergy transmission system spans four states, 114,000 square miles and six regulatory jurisdictions (including the Federal Energy Regulatory Commission).

The energy delivery function plans, engineers, builds and operates 16,500 miles of 69kV - 500kV transmission lines. As a member of the Southeastern Electric Reliability Council, Entergy is committed to serving its customers reliably across its interconnected grid of wires and substations.



Acadiana Load Pocket Reliability Project presentation



Holland Bottom presentation

The system moves bulk power from generating plants to distribution points for delivery to wholesale customers and cooperatives as well as to approximately 2.7 million retail customers of Entergy Arkansas, Inc., Entergy Louisiana, LLC and Entergy Gulf States Utilities, L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc. and Entergy Texas, Inc.

The system operations center in Pine Bluff, Ark. has overall responsibility for operations. Transmission operations centers for Entergy's operating companies are located in the areas those companies serve.

The Entergy transmission system is part of the Eastern Interconnection, the network of interconnected transmission systems that move bulk power throughout the eastern third of the United States and eastern Canada.

Entergy's energy delivery function headquarters is in Jackson, Miss.

Disclaimer: This web site is provided for the convenience of Entergy's transmission

service customers. While every effort is made to ensure the information contained herein is accurate, Entergy does not guarantee its accuracy or that the transfer capability information contained herein is available. Entergy's official transfer capability information is posted on the Entergy OASIS in accordance with FERC directives. Entergy shall not be liable for damage, loss, injury, or any other claims of whatever nature arising from the publication of the information at this site Please review this page periodically to see if any enhancements or new features have been added.

http://www.entergy.com/energydelivery/transmission_system_facts.aspx

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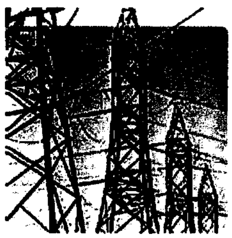
Transmission System Facts



- 16,500-plus miles of inter-connected lines; approximately 1,300 substations; serves six operating companies
- Governed by six regulatory agencies.
- Entergy's Independent Coordinator of Transmission is the Federal Energy Regulatory Commission-approved Reliability Coordinator for grid security and stability and administers Entergy's Open Access Transmission Tariff and planning functions.
- The Southwest Power Pool serves as the Independent Coordinator of Transmission.
- Among other duties, the ICT serves as the Reliability Coordinator and Tariff Administrator for Entergy's transmission system.

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http://www.spp.org/publications/Entergy-SPP WPP Process Launches.pdf

SPP Southwest Power Pool

FOR IMMEDIATE RELEASE

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Entergy and SPP ICT Weekly Procurement Process Successfully Launches

March 30, 2009, LITTLE ROCK, ARKANSAS – Entergy Services, Inc.'s first Weekly Procurement Process (WPP) was successfully completed on Friday, March 27 with oversight from Southwest Power Pool, Inc., which serves as the Independent Coordinator of Transmission (ICT) for Entergy. Implementing the WPP marks the culmination of a collaborative effort to develop a creative generation bid-based process that considers transmission limitations.

According to Mark McCulla, Entergy vice president of transmission regulatory compliance, "The power market in Entergy's service area is robust and dynamic. This new process is another step toward fostering market efficiencies and customer savings."

The WPP relies on a unique set of computer software that lets generators competitively bid to provide power to meet Entergy's system requirements for the upcoming week. It is an optimized procurement process, not a centralized market for energy. The WPP receives information from bidding generators and calculates whether accepting some or all of these bids, taking into account the expected configuration and limits on the transmission system, will produce a more economic mix of resources than the operating companies' existing resources.

The WPP is intended to provide Entergy and its network customers optimized, short-term (weekly) purchases of wholesale energy, factoring in the transmission system's expected capability, operating constraints, and the operating companies' existing resources. The WPP will be performed each week on Wednesday and Thursday for the upcoming operating week.

One measure of the benefits of the WPP will be the estimated production cost savings that result from the resources obtained through the WPP process. "We are pleased to have implemented this important ICT service," said Bruce Rew, SPP vice president of engineering. "This effort provides the opportunity for the ICT to realize its full benefit and potential."

The WPP is a fundamental part of the SPP ICT. The Federal Energy Regulatory Commission (FERC) approved Entergy's proposal to establish an ICT in 2006, and Entergy identified the SPP as its ICT. The ICT's responsibilities include calculating Available Flowgate Capability, granting or denying transmission service, administering Entergy's Open Access Same Time Information System, performing an enhanced planning function, and overseeing the WPP

###

Southwest Power Pool, Inc. is a group of 53 members serving more than four million customers across nine states of the Eastern Interconnection. Membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, wholesale generators, power marketers, and independent transmission companies. SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by FERC as a regional transmission organization in 2004 and a regional entity in 2007. SPP.org

Entergy Corporation is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity, and it is the second-largest nuclear generator in the United States. Entergy delivers electricity to 2.7 million utility customers in Arkansas, Louisiana, Mississippi and Texas. Entergy has annual revenues of more than $13 billion and approximately 14,300 employees. Entergy.com

ETI Response to Staff RFI 7-3a

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc.	Prepared By: Harold Keys
to the Seventh Set of Data Requests	Sponsoring Witness: Richard C. Riley
of Requesting Party: Commission Staff	Beginning Sequence No. TH96
	Ending Sequence No. TH99

Question No.: STAFF 7-3 Part No.: Addendum:

Question:

Page 75 of Exhibit A, Attachment B of the Application states that there are 41 interconnections between SPP and the Entergy Operating Companies. Please provide the following:

a. Please list each of the 41 interconnections and provide the transmission line length, line rating, line voltage, SPP member to which it interconnects, whether that SPP member is a member of the SPP RTO Market, and the Entergy Operating Company to which it interconnects.

b. Please explain if these lines can be utilized for transmitting power between Entergy and MISO and discuss transfer limits and restrictions for doing so.

c. Please explain how much generation capacity was accessible by Entergy from SPP for each of the last five years.

d. Please explain if Entergy anticipates maintaining these 41 interconnections as they currently exist if the proposed transfer of operational control to MISO RTO is approved.

e. Please explain if Entergy anticipates losing access to generation from SPP if the proposed transfer of operational control to MISO RTO is approved, and if so, how much.

Response:

a. See the table below. The list includes 45 interconnections, instead of 41, because of transmission upgrades that were recently placed in service in the Acadiana area of south Louisiana. The Acadiana projects created three new ties between EGSL and Cleco. The list also includes the normally-open tie line between the Emmet and Hope North Substations.

ETI Response to Staff RFI 7-3a

Question No.: STAFF 7-3

From			To						
(a) Entergy OpCo	(b) From Substation	(c) Voltage (kV)	(d) SPP Member company	(e) Within SPP RTO footprint? (Yes/No)	(f) To Substation	(g) Voltage (kV)	(h) Circuit ID	(i) Rating (MVA)	(j) Est. line length (miles)
EAI	Murfreesboro South	138	AEP-West	Yes	South Nashville	138	1	97	19.5
ELL	Ringold	138	Cleco	No	Carroll	138	1	137	15.2
ETI	Bon Weir	138	Cleco	No	Cooper	138	1	143	22.5
EGSL	Bayou Warehouse	138	Cleco	No	Ivanhoe	138	1	143	6
EGSL	Cecelia	138	City of Lafayette	No	Bonin	138	1	145	14.2
EAI	Calico Rock	161	SPA	No	Norfork	161	1	148	8.12
EAI	Patmos West	115	AEP-West	Yes	Fulton	115	1	150	15
EAI	Midway	161	SPA	No	Bull Shoals	161	1	162	9.1
EAI	Harrison East	161	SPA	No	Bull Shoals	161	1	223	33.8
EAI	Harrison East	161	EMDE	Yes	Ozark Beach	161	1	134	40.4
EAI	Hill Top	161	SPA	No	Bull Shoals	161	1	204	35.8
EAI	Heber Springs North	161	SPA	No	Greers Ferry	161	1	167	1.5
EAI	Hill Top	161	SPA	No	Dardanelle	161	1	189	61.9
EAI	Dardanelle	161	SPA	No	Dardanelle Dam	161	1	223	1.9
EAI	Jonesboro	161	SPA	No	Jonesboro SPA	161	1	309	0.8
EAI	Water Valley APL	161	SPA	No	Water Valley	161	1	160	
EAI	Jonesboro	161	SPA	No	Hergett	161	1	148	14.9
EAI	Trumann	161	SPA	No	Hergett	161	1	148	8.3
EAI	Harrison East	161	AEP-West	Yes	Eureka Springs	161	1	210	45.9
EGSL	Scott	138	City of Lafayette	No	Bonin	138	1	225	5.2
ETI	Toledo Bend	138	Cleco	No	Leesville	138	1	143	22.6
ELL	Gibson	138	Cleco	No	Ramos	138	1	253	8.4
EGSL	Nelson	138	Cleco	No	Deridder	138	1	262	39.6
ETI	Toledo Bend	138	Cleco	No	Fisher	138	1	143	25.8
EGSL	Richard	138	Cleco	No	Eunice	138	1	243	6.1
EGSL	Richard	138	Cleco	No	Habetz	138	1	243	13.1
EGSL	Champagne	138	Cleco	No	Plaisance	138	1	191	12.8
EGSL	Moril	138	Cleco	No	Hopkins	138	1	287	2.5
EAI	Russellville South	161	SPA	No	Dardanelle	161	1	335	3
EAI	Danville	161	AEP-West	Yes	North Magazine	161	1	335	26
ELL	Montgomery	230	Cleco	No	Clarence	230	1	414	12.8
EGSL	Nelson	230	Cleco	No	Perton	230	1	418	14.6
EGSL	Meaux	230	Cleco	No	Sellers Road	230	1	433	9.4
EGSL	Richard	138	Cleco	No	Acadia	138	1	497	0.2
EGSL	Richard	138	Cleco	No	Acadia	138	2	497	0.2
EGSL	Moril	138	Cleco	No	Segura	138	1	439	0.5
ELL	Montgomery	230	Cleco	No	Colfax	230	1	791	16.9
ETI	Grimes	345	AEP-West	Yes	Crockett	345	1	1194	64.2
ELL	Sarepta	345	AEP-West	Yes	Longwood	345	1	896	40.4
EAI	ANO	500	Oklahoma Gas & Electric	Yes	Fort Smith	500	1	1299	93.6

ETI Response to Staff RFI 7-3a

Question No.: STAFF 7-3

From			To				(h) Circuit ID	(i) Rating (MVA)	(j) Est. line length (miles)
(a) Entergy OpCo	(b) From Substation	(c) Voltage (kV)	(d) SPP Member company	(e) Within SPP RTO footprint? (Yes/No)	(f) To Substation	(g) Voltage (kV)			
EGSL	Richard	500	Cleco	No	Rork	230	1	750	N/A (Transformer)
EGSL	Wells	500	Cleco	No	Wells	230	1	550	N/A (Transformer)
ELL	Fisher	115	Cleco	No	Fisher	138	1	120	N/A (Transformer)
ELL	Beaver Creek	115	Cleco	No	Beaver Creek PS	138	1	93	N/A (Transformer)
EAI	Emmett	115	AEP-West	Yes	Hope North	115	1	159	9.8

b. ETI is not aware of any restrictions that are placed on the use of the "41 interconnections" between SPP and the Entergy Operating Companies other than the tiecaps associated with transactions between neighboring transmission providers. Transmission facility ratings are generally limited by their thermal ratings. To the extent certain of SPP's facilities are limited by factors other than thermal capability, ETI is not aware of such limitations. However, ETI notes that one of the interconnections to SPP is a tie between Cleco and Entergy Gulf States Louisiana at the Beaver Creek substation. The Beaver Creek Substation phase shifting transformer controls and limits the flow on this transformer.

Like other transmission facilities, transmission lines that interconnect the Entergy Transmission System with SPP members that are not part of the SPP RTO Market are an integral part of the interconnected transmission network known as the Eastern Interconnection. These transmission facilities could be used to transmit power between regions, including between the Entergy Transmission System and MISO or SPP. The use of such facilities is dependent on a number of factors including, but not limited to, the transfer path, generation dispatch, amount of the power transfer, other transactions on the system, other system characteristics such as transmission line impedance, transmission topology, and the electrical load demand.

The amount of additional energy that may be transferred between the existing MISO footprint and the Entergy Region will depend in part on the amount of capacity on reciprocal coordinated flowgates that is allocated to MISO, and the degree to which these flowgates become congested during real-time operation.

c. The Company does not have this information.

ETI Response to Staff RFI 6-18

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc. to the Sixth Set of Data Requests	Prepared By: Jonathan Bourg
	Sponsoring Witness: Richard C. Riley/Michael M. Schnitzer
of Requesting Party: Commission Staff	Beginning Sequence No.
	Ending Sequence No.

Question No.: STAFF 6-18 Part No.: Addendum:

Question:

Regarding SPP or any other transmission entities that may be impacted by flows between MISO and ETI (other than on the 1,000 MW contract path):

a. Has CRA or ETI estimated the potential congestion costs on the SPP system or other affected transmission entities that would result from loop flows on these systems?

b. If neither CRA nor ETI has estimated the potential congestion costs on the SPP system or other affected transmission entities that would result from loop flows, what assurance does ETI have that its estimated higher benefits from joining MISO would not be reduced if ETI had to pay for such congestion costs?

Response:

a. Yes. SPP retained Charles River Associates ("CRA") to perform an assessment of the potential change in energy flows on the SPP transmission system assuming the Entergy Operating Companies and Cleco Power integrate into MISO (the "SPP Sponsored Assessment"). As part of this assessment, CRA estimated the amount of redispatch compensation that would be required after a "market-to-market" congestion management procedure is adopted under the Joint Operating Agreement between MISO and SPP. CRA estimated payment amounts from MISO to SPP of $3.5 million in 2013.

ETI has analyzed CRA's SPP Sponsored Assessment. Taken at face value, the congestion compensation calculated by CRA is *de minimis* when compared to the significant net benefits associated with the Entergy Operating Companies' and Cleco Power's integration into MISO as determined in the May 12, 2011 Evaluation Report – between $1.066 billion and $1.393 billion on a ten-year net present value basis for all Operating Companies and between $170 million and $225 million on a net

Question No.: STAFF 6-18

present value basis for ETI alone.[1] Further, any compensation due to SPP for loop flows would be due in accordance with the Joint Operating Agreement between MISO and SPP. Such compensation amounts would be due from MISO, not any of the Entergy Operating Companies, and MISO would enter into a transaction that would require compensation only if the benefits of the transaction exceeded the costs (including any compensation due for loop flows).

In addition, the Company has identified several deficiencies with CRA's SPP Sponsored Assessment that cause the estimated costs associated with redispatch to be overstated. For a discussion of these deficiencies, see the attached portions of testimony in Arkansas Public Service Commission Docket No. 10-011-U: (i) pages 8-26 of the Rebuttal Testimony of Michael M. Schnitzer filed on April 13, 2012 and (ii) pages 4-5 and 13-19 of the Rebuttal Testimony of Richard C. Riley filed on April 13, 2012.

Finally, in FERC Docket No. EL11-34-000, Entergy Services, Inc. submitted an affidavit which explained that CRA's cost-benefit analyses of RTO membership "provide information on hourly generation levels in the Entergy/Cleco region for each case – Status Quo, Join SPP and Join MISO – as well as the amount imported into the region." See Limited Answer of Entergy Services, Inc., FERC Docket No. EL11-34-000, Affidavit of Michael M. Schnitzer at 7 (filed on May 25, 2011). That affidavit explained that CRA's data show that "average annual net generation inside the Entergy/Cleco footprint is basically the same in the two Join RTO cases as it is in the Status Quo case -- and the average annual imports from outside the region are therefore also unchanged from the Status Quo to either of the Join RTO cases. Put another way, there is no 'flood' of new imports into the Entergy/Cleco region in either of the Join RTO cases." *Id.* Finally, the affidavit explained that the data:

> shows that joining either RTO is projected to have an impact on congestion on adjacent systems. However, it shows that while there is an increase in congestion on the SPP system in the Join MISO case ($6.6 [million]/yr), there is a slightly larger increase in congestion on flowgates in the MISO region in the Join SPP case ($7.7 [million]/yr). Further, for the non-SPP/MISO/Entergy regions, congestion is reduced in the Join MISO case, but congestion increases for these systems in the Join SPP case.

Id. at 9. The SPP Sponsored Assessment identifies $3.5 million in compensation for redispatch for the year 2013. The earlier figure for the

[1] The SPP Sponsored Assessment did not specify which parties would be responsible for the estimated congestion compensation costs.

Question No.: STAFF 6-18

Join MISO case thus was higher than the range of redispatch compensation identified in the SPP Sponsored Assessment.

b. Not applicable. See the Company's response to subpart (a) above.

Rebuttal Testimony of Michael M. Schnitzer, Energy Arkansas, Inc. (Docket No. 10-011-U) at 12:13-15.

Arkansas even when potential increases in congestion on the transmission system are taken into account. By assuming no JOA for purposes of calculation of production cost savings, and assuming a JOA with compensation for congestion, Mr. Luciani's analysis provides a conservative estimate for trade benefits.

Q. IS THERE CURRENTLY A MARKET-TO-MARKET PROTOCOL IN PLACE UNDER THE JOA?

A. No. A so-called market-to-non-market protocol is used, meaning that if congestion on an RCF occurs, the North American Electric Reliability Corporation's ("NERC") Transmission Loading Relief ("TLR") procedures are used to reduce flows of the party exceeding its allocated share of the RCF, and no compensation is due. It is my understanding that MISO and SPP are discussing possible adoption of market-to-market protocols under the JOA.

Q. DOES THE SPP SPONSORED ASSESSMENT ADDRESS OPERATIONS PRIOR TO ADOPTION OF MARKET-TO-MARKET PROTOCOLS UNDER THE JOA?

A. No. According to Mr. Monroe, CRA did not perform any additional studies to address operations prior to adoption of market-to-market protocols.[19]

[19] Monroe Direct Testimony at 22 (March 16, 2012).

Rebuttal Testimony of Michael M. Schnitzer, Energy Arkansas, Inc. (Docket No. 10-011-U) at 22:15-19.

NET BENEFITS?

A. The MISO market operator would factor the market-to-market protocols into the security constrained economic dispatch algorithms it uses to dispatch generation.[33] The compensation costs would be taken into account in determining whether to dispatch generation at levels that would trigger compensation, and the new dispatch would be implemented only if the resulting estimated production cost savings exceed the cost of compensation.[34] This is the process, for example, under the market-to-market protocols used by MISO and PJM Interconnection, L.L.C. ("PJM").[35]

Q. WHICH OF THE TWO REDISPATCH COMPENSATION ESTIMATES INCLUDED IN THE SPP SPONSORED ASSESSMENT – $6.5 MILLION OR $3.5 MILLION – IS THE MORE RELEVANT FIGURE?

A. As between the two figures, the $3.5 million estimate is the more relevant figure. The $6.5 million estimate is based on an average shadow price for all constraining RCFs in the CRA models. The $3.5 million estimate, on the other hand, is based on flowgate specific shadow prices associated with the constrained flowgates that lead to compensation under the study. As such, it mirrors the actual calculation methodology under MISO's

[33] *See* Doying Direct Testimony at 14 (March 16, 2012).
[34] *See* Exhibit JPH-19 at 102-103 (Deposition of Ralph Luciani, March 29, 2012); EAI Exhibit JPH-17 at 161-163 (Deposition of Carl Monroe, March 27, 2012).
[35] *See* Exhibit JPH-19 at 102-104 (Deposition of Ralph Luciani, March 29, 2012).

MISO Response to Staff RFI 5-1 and 5-2

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR ("MISO")
PUC DOCKET NO. 40346; SOAH DOCKET NO. 473-12-6206
(Request Date: July 2, 2012)

Response of:	MISO
To:	Public Utility Commission of Texas, Fifth Request for Information
Response Date:	July 12, 2012

Question No.: 5-1

a. Has MISO performed any preliminary assessment of reliability-driven transmission projects that would be associated with Entergy joining MISO?

b. If so, please provide any such assessments. If not, why?

Response:

a. No, although MISO has determined that no reinforcement projects are necessary to integrate Entergy into MISO. No further study of the need for any transmission reinforcements to integrate Entergy into MISO is necessary

b. Although MISO currently is not Entergy's transmission planner, MISO has followed closely and attended the ICT meetings and other regional planning efforts, which combined with our planning experience, will allow us to identify transmission plans in a timely manner upon Entergy's integration.

Question 5-1 Sponsor: Jennifer Curran

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR ("MISO")
PUC DOCKET NO. 40346; SOAH DOCKET NO. 473-12-6206
(Request Date: July 2, 2012)

Response of:	MISO
To:	Public Utility Commission of Texas, Fifth Request for Information
Response Date:	July 12, 2012

Question No.: 5-2

a. Has MISO performed any preliminary studies on transmission reinforcements that need to be done to overlap Entergy and MISO?

b. If so, please provide any such studies. If not, why?

Response:

a. See Response to 5-1.

b. See Response to 5-1.

Question 5-2 Sponsor: Jennifer Curran

ETI Response to Staff RFI 5-5.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc. to the Fifth Set of Data Requests	Prepared By: Kham Vongkhamchanh Sponsoring Witness: Richard C. Riley / John P. Hurstell
of Requesting Party: Commission Staff	Beginning Sequence No. Ending Sequence No.

Question No.: STAFF 5-5 Part No.: Addendum:

Question:

Please provide the historical estimated costs of transmission constraints based on TLRs, including any costs of resolving congestion (providing costs for when this was resolved through re-dispatching), and the cost of lost opportunities for ETI ratepayers due to congestion (providing the costs of curtailment of transactions) by year for the past 10 years.

Response:

No analysis has been performed to quantify the historical estimated costs of transmission constraints based on TLRs.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc. to the Sixth Set of Data Requests of Requesting Party: Commission Staff

Prepared By: Joseph L. Payne
Sponsoring Witness: Richard C. Riley
Beginning Sequence No.
Ending Sequence No.

Question No.: STAFF 6-6 Part No.: Addendum:

Question:

Are there any planned transmission projects for ETI's system that are designed to relieve congestion on ETI's system? If so, please provide a list of these projects, the congested areas they are intended to serve, their estimated in-service dates, and their estimated costs.

Response:

Entergy's 2012 – 2016 Final Construction Plan Update 2 includes planned transmission projects for which construction is planned to start within the current five year construction plan window. The relief of congestion is not listed as a primary driver associated with these projects, as reflected in the Construction Plan. Primary drivers, as reflected in the Construction Plan, include: meeting or enhancing reliability; economic upgrades; upgrades identified in response to a transmission service request; and upgrades required for generation interconnection service. However, projects listed in the Final Construction Plan may also result in relieving congestion because the project may increase the capacity of the limiting element of a commonly invoked flowgate or may result in eliminating the contingent element of a commonly invoked flowgate. Entergy's 2012 – 2016 Final Construction Plan Update 2 can be found on Entergy's OASIS at
http://www.oatioasis.com/EES/EESDocs/Entergy_2012-2016_Final_Construction_Plan_Update_2.pdf

As part of Entergy's open and transparent planning process, Entergy also publishes a monthly construction plan report which includes flowgates that are considered to be associated with a specific construction plan project. The report also includes the planned and projected in-service dates and includes references to each operating company. The monthly construction plan report can be found on Entergy's OASIS at
http://www.oatioasis.com/EES/EESDocs/monthlyconstructionplan.htm

For the estimated cost of the Construction Plan projects see the Company's response to Staff 3-21.

See also the Company's response to Staff 6-7.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Michal J. Goin Sponsoring Witness: John P. Hurstell Beginning Sequence No. TH1 Ending Sequence No. TH1

Question No.: TIEC 1-13   Part No.:   Addendum:

Question:

Please state whether ETI has developed a cost-benefit analysis of joining MISO assuming that Entergy Arkansas Inc. (EAI) does not join MISO. If the response is yes, please provide a copy of the analysis. If the response is no, please explain why this option was not analyzed.

Response:

ETI has not developed such an analysis. It is EAI's intent to join MISO.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
SOAH DOCKET NO. 473-12-6206
PUC DOCKET NO. 40346

Response of: Entergy Texas, Inc.	Prepared By: Jonathan Bourg/Joe Payne
to the Third Set of Data Requests	Sponsoring Witness: Richard C. Riley
of Requesting Party: Commission Staff	Beginning Sequence No.
	Ending Sequence No.

Question No.: STAFF 3-21 Part No.: Addendum:

Question:

Please provide data on the total and individual costs of all proposed, in target, and approved transmission projects under the latest versions of

a. the Entergy 2012-2016 Construction Plan and

b. the ICT 2012 Base Plan.

Response:

The Company objects to this request on grounds that the responsive materials are protected ("confidential") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101, 552.104 and/or 552.110. Confidential materials will be provided pursuant to the terms of the Protective Order in this docket.

a. The attached confidential document titled "Entergy 2012 - 2016 Final Construction Plan Update 2 WITH Cost Estimates Confidential.pdf" lists the projects in the current 2012-2016 Transmission Construction Plan (Update 2) as well as the presently-estimated cost of those projects.

b. As stated in the February 2012 SPP Report on Differences between the 2012 ICT Base Plan and the 2012-2016 Entergy Construction Plan,[1] "[a]ll projects in the ICT Base Plan are included in the Entergy Construction Plan." Therefore, the presently-estimated costs of the projects included in the ICT 2012 Base Plan are reflected in the confidential document provided in the Company's response to part a. The Company does not have information on costs that SPP may have assigned to the projects included in the ICT 2012 Base Plan.

[1] A copy of this report is available at http://www.oatioasis.com/EES/EESdocs/Complete_2012-2016_Differences_Report_Final.pdf.

Public Utility Commission of Texas **Workpapers**

Docket No. 40346

HIGHLY SENSITIVE CONFIDENTIAL FILING

Please refer to the following highly sensitive protected materials previously filed in this docket:

ETI Response to Staff 3:21 Bate Stamp SS51 to SS53, Item No. 102

Pursuant to Paragraph 7 of the Protective Order issued in this proceeding, Staff will provide sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record.