FILED
July 9, 2013
Data Center
Missouri Public
Service Commission

BEFORE THE

MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	)	**File No. EO-2013-0396**

DIRECT TESTIMONY AND EXHIBITS

OF

THOMAS W. VITEZ

ON BEHALF OF ITC MIDSOUTH LLC

APRIL 2013

ITC Exhibit No. 12
Date 6-18-13 Reporter XF
File No. EO-2013-0396

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas W. Vitez. My business address is 27175 Energy Way, Novi, Michigan 48377.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by ITC Holdings Corp. as its Vice President of Planning.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science Degree in Electrical Engineering from the University of Cincinnati in 1986, and a Master of Business Administration Degree from the University of Michigan in 1992.

Q4. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have been involved in the utility industry for the past thirty-one years. I began my career in 1981 as an intern at the Cleveland Electric Illuminating Company (now a subsidiary of FirstEnergy Corp.). In 1986, as an Underground Engineer, I was responsible for residential development of distribution systems. In 1992, I joined The Detroit Edison Company (*"**Detroit Edison**"*) in its Professional Opportunity Program – a two year developmental program with a variety of assignments, including Transmission Planning. In 1994, I was assigned to the Demand Side Management section of the Marketing Department where I analyzed demand side management options. In 1995, I returned to Transmission Planning where I performed studies of Detroit Edison's transmission system. In 1998, I was promoted to Principal Engineer in Transmission Projects.

When Detroit Edison formed a separate transmission subsidiary, I was appointed Principal Engineer in Transmission Projects. In 2003, I joined ITC Holdings Corp. as its Director—Transmission Planning. I subsequently was promoted to Director—Reliability Planning in 2006, and to my current position in 2007. I am responsible for all transmission system planning in my current position.

Q5. DO YOU PARTICIPATE IN ANY INDUSTRY WORKING GROUPS OR OTHER PROFESSIONAL ORGANIZATIONS?

A. Yes. I have served on a variety of industry working groups and panels. Most recently, I served on Michigan's Wind Energy Resource Zone Board representing independent transmission companies. I am the past Chairman of the East Central Area Reliability Council's ("***ECAR***") Future System Study Group as well as the ECAR Transmission System Performance Panel Working Group. I also served on the North American Electric Reliability Corporation ("***NERC***") Distribution Factors Task Force. With respect to the Midwest Independent Transmission System Operator, Inc. ("***MISO***"), I am the past Chairman of MISO's Expansion Planning Group and currently serve as an active participant on MISO's Planning Advisory Committee. Finally, I served as Chairman of the Transmission and Distribution Group for the Michigan Public Service Commission's Capacity Needs Forum.

Q6. PLEASE DESCRIBE YOUR GENERAL JOB RESPONSIBILITIES AS VICE PRESIDENT OF PLANNING.

A. As Vice President of Planning, I oversee the planning and expansion of the transmission system for the corporate operating companies, including International Transmission Company ("*ITCT*"), Michigan Electric Transmission Company, LLC ("*METC*"), ITC Midwest LLC ("*ITCMW*"), and ITC Great Plains, LLC ("*ITCGP*") (along with ITC Holdings Corp., collectively referred to as "*ITC*"). I plan expansions to the transmission system by developing planning models, performing assessments of expected future system performance, and studying requests to interconnect load and generation. I also oversee compliance with applicable planning standards, set internal transmission planning related policies, and work with stakeholders on transmission planning related issues. Load forecasting and economic analysis are also part of my transmission planning organization.

Q7. PLEASE DESCRIBE YOUR PLANNING DEPARTMENT'S ORGANIZATIONAL STRUCTURE.

A. I report directly to the company's Executive Vice President and Chief Operating Officer, Mr. Jon Jipping, who also is a witness in this proceeding. Currently my organization is comprised of approximately thirty-six employees, including myself. My direct reports include five Managers (a Manager of Michigan Planning, Manager of Midwest Planning, Manager of Regional Planning, Manager of Planning Policies, and Manager of ITCGP), a Senior Staff Engineer, and an administrative assistant. We have several types of positions that report to the Managers, including Principal Engineers, Senior Engineers, Engineers, Associate Engineers, a Senior Economic Analyst, an Economic Analyst, an Engineering Tech, a Senior Programming Analyst, and a Co-Op student. A copy of my group's organizational chart is attached as **Exhibit TWV-1**.

Q8. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE REGULATORY COMMISSIONS OR IN COURT PROCEEDINGS?

A. Yes. I testified before the Iowa Utilities Board in Docket No. SPU-07-11 and before the Minnesota Public Utilities Commission in Docket No. E-001/PA-07-540, both in support of ITMW's 2007 acquisition from Alliant Energy of the transmission assets of Interstate Power & Light Company. I also testified before the Michigan Public Service Commission in the following cases:

1) Case No. U-14861, concerning the application of ITCT for a certificate of public convenience and necessity for the construction of a transmission line running from and through Genoa, Oceola, Hartland, Brighton, and Milford Townships in Livingston and Oakland Counties in Michigan.

2) Case Nos. U–12780 and U-12781, concerning actions taken by ITCT to expand the firm commercial import capability of Michigan's transmission system by 2,000 MWs to accommodate new projects identified in a "Joint Report" filed with the Michigan Public Service Commission by ITCT, Consumers Energy Company, and Great Lakes Energy Cooperative in December 2000.

3) Case No. U-16200, requesting a transmission line siting certificate for ITCT's "Thumb Loop Project".

I also testified in Docket No. ER09-681-000 at the Federal Energy Regulatory Commission (*"FERC"*) where I explained the technical analysis that led to and supported our Green Power Express (*"GPE"*) project, the purpose of which was to significantly increase the amount of power that can be moved from regions with favorable renewable resource attributes to load centers.

Additionally, I am testifying in Texas, Louisiana, the City of New Orleans, Arkansas, and Mississippi regarding the transaction that is the subject of this proceeding.

Q9. ARE YOU SPONSORING ANY EXHIBITS AS PART OF THIS FILING?

A. Yes. I am sponsoring the following Exhibits:

Exhibit TWV-1	**ITC Planning Department Organizational Chart**
Exhibit TWV-2	**Transmission Planning Criteria**
Exhibit TWV-3	**MISO Entity Organizational Chart**

II. PURPOSE AND SUMMARY OF TESTIMONY

Q10. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On December 4, 2011, Entergy Corporation and ITC entered into a definitive agreement under which the Entergy Operating Companies[1] will separate and then merge their electric transmission business into a subsidiary of ITC ("***Transaction***"). This is a multi-state transaction involving the Entergy transmission operations in Louisiana, Arkansas, Mississippi, Texas, New Orleans, and a small portion of Missouri. The Transaction is subject to approval of the retail jurisdictions, FERC, and other federal agencies. In support of this Transaction, the parties are filing a joint application for change of control and any other necessary regulatory approvals in each of the respective regulatory jurisdictions.

My testimony is filed on behalf of ITC Midsouth LLC. I will discuss ITC's independent transmission planning process and how the process is superior to transmission planning within a vertically integrated utility. My testimony will explain how ITC's singular focus on transmission and its independence from market participants allow it to collaborate with others and plan the transmission system with a broad regional view that facilitates wholesale markets. In particular, I will describe and explain:

(1) the transmission planning processes used by MISO;

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[1] The Entergy Operating Companies are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Gulf States Louisiana, L.L.C. ("EGSL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENO"), and Entergy Texas, Inc. ("ETI").

(2) the transmission planning processes used by ITC and how they align with the MISO transmission planning processes;

(3) the benefits of ITC, as an independent transmission company, engaging in transmission planning;

(4) how ITC's ownership of EAI's transmission assets will provide benefits in excess of what could be expected from EAI's participation in an RTO planning process; and

(5) ITC's plans with respect to the current Entergy transmission projects.

Q11. PLEASE SUMMARIZE YOUR TESTIMONY.

A. First, ITC has a proven track record of planning its transmission systems to: (1) address local, state, and regional reliability needs; (2) increase the economic efficiency of the overall grid; and (3) respond to transmission needs identified in state and regional processes. When deficiencies are identified on the transmission system, such as inadequate capacity to meet load under certain contingency conditions, ITC's transmission planners develop transmission system reinforcements to address those deficiencies. The reduction of transmission system constraints can result in more economic dispatch of generation, ultimately reducing energy costs to end-use customers. These practices expand market access and also confer value through the planning and operation of a more robust, reliable transmission grid. ITC has followed through on the projects that come out of this transmission planning approach by making significant investment in its transmission systems.

Second, ITC is committed to planning its transmission system in an open and transparent manner. As such, ITC has its own processes that supplement the already-robust open and transparent processes used by MISO. Together, the MISO and ITC processes provide ITC with an opportunity to solicit feedback from regulators and stakeholders[2] about identified and perceived transmission planning needs and potential solutions.

Finally, the Transaction enhances customer benefits beyond what could be achieved through the Entergy Operating Companies' MISO membership. MISO has historically employed a bottom-up planning process that depends on the local knowledge and requirements of each Transmission Owner to identify projects required to support both local and regional needs. MISO, as an RTO, has no ability or mandate to build transmission facilities to meet the demands of the wholesale market. ITC has proven it has the expertise, resources, and capital not only to plan but also to construct needed investment. In addition, ITC's regional approach to transmission planning will enhance deliverability of generation throughout the region to provide a more economic source of energy for customers.

III. TRANSMISSION PLANNING UNDER AN RTO

[2] Examples of stakeholders include industrial customers, electric cooperatives, municipal utilities, communities, marketers, generators, load serving entities, business groups, legislators, and energy advocacy groups.

Q12. DOES ITC PARTICIPATE IN AN RTO PLANNING PROCESS?

A. Yes, ITC participates in MISO's and Southwest Power Pool's FERC approved open and transparent planning processes. In Order No. 890[3], FERC set forth nine planning principles associated with transmission planning: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. Further, FERC required that a coordinated, open and transparent planning process be utilized on the local and regional level, and that the planning process be described in the tariff.

Q13. PLEASE PROVIDE A HIGH LEVEL DESCRIPTION OF THE MISO REGIONAL PLANNING PROCESS IN WHICH ITC PARTICIPATES.

A. MISO is registered with NERC as a Planning Authority.[4] In this capacity, MISO performs regional planning of the transmission systems by evaluating and planning for the reliability of the transmission system in accordance with NERC's Reliability Standards and other criteria, as explained in Attachment FF of MISO's tariff. Although MISO performs planning functions collaboratively with its

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[3] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[4] MISO is the FERC-approved RTO which has functional control over transmission assets of ITCT, METC, and ITCMW rated 69 kV and above.

Transmission Owners, MISO also provides an independent assessment and perspective of the transmission system's overall needs.

Each year, MISO and its members report the outcome of its annual planning cycles to the MISO Board of Directors, resulting in the annual MISO Transmission Expansion Plan ("*MTEP*"). The project information exchange cycle starts when stakeholders submit newly proposed projects, usually in early September. Throughout the MTEP process, Planning Advisory Committee, Planning Subcommittee, Subregional Planning Meetings ("*SPM*") and other more local meetings such as the Michigan Technical Task Force ("*MITTF*") are held. The purposes of the meetings are to provide MISO, Transmission Owners, stakeholders and regulators with an opportunity to discuss study results, the future needs of the transmission system, and the transmission projects proposed to meet those needs. MISO then spends approximately one year evaluating the projects for inclusion in the MTEP. Then, by the following September (approximately one year after the start of the planning cycle), MISO submits a proposed MTEP to the MISO Board of Directors. The MISO Board subsequently evaluates the MTEP and determines whether approval of the plan is warranted (typically within the December timeframe)[5].

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[5] A copy of the latest MTEP can be accessed at: https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx

The projects listed in Appendix A of the MTEP constitute the essential transmission projects recommended to the MISO Board of Directors for review and approval. MISO believes, in aggregate, that the Appendix A projects will:

- Ensure the reliability of the transmission system;
- Provide economic benefits such as increased market efficiency;
- Facilitate public policy objectives such as integrating renewable energy; and
- Address other issues or goals identified through the stakeholder process.

The projects listed in Appendix B of the MTEP Report represent proposed projects for which a need has been identified, but require additional analysis. Appendix C of the MTEP Report contains more conceptual projects for which the need has not been verified. This MISO planning process assures that the transmission projects developed by individual Transmission Owners, such as ITC, will be properly integrated with other proposed projects within MISO and that these projects will be fully vetted in an open and transparent manner.

The Transmission Owners in the MISO region, including ITCT, METC, and ITCMW, typically perform the initial planning for their individual transmission systems by detecting deficiencies, selecting the alternatives that they want to advance as proposed projects, and submitting the proposed projects into the MISO planning process. MISO does not typically initiate transmission projects to be built by the Transmission Owners unless the projects are regional in nature and affect several pricing zones and other MISO member Transmission

Owners. More recently, MISO has submitted regional projects to the MTEP for future study consistent with the thrust of FERC Order 1000. Under FERC Order 1000, RTOs are directed to take a more active role in regional planning.

Q14. HOW DO THE MULTIPLE SUBREGIONAL AND LOCAL MEETINGS HELD THROUGHOUT THE MTEP PROCESS ENSURE SUFFICENT INPUT FROM STAKEHOLDERS AND REGULATORS?

A. As mentioned above, MISO holds SPM's and more local meetings throughout the MTEP process in addition to the regional Planning Advisory Committee and Planning Subcommittee meetings. While the regional Planning Advisory Committee and Planning Subcommittee meetings typically focus more on the higher level issues that impact MISO as a whole, the local meetings are typically held close to the regions they focus on and allow for more detailed discussions around specific projects in each local region. The meetings provide a forum for stakeholders and regulators to comment on the project proposals and submit additional project proposals for consideration in the MTEP process.

Q15. WHAT INPUTS TYPICALLY ARE CONSIDERED IN THE REGIONAL PLAN ADOPTED BY MISO?

A. MISO generally considers:

- Transmission needs identified by the Transmission Owners in connection with their planning analyses, in accordance with their local planning process, to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion;
- Transmission planning obligations of a Transmission Owner imposed by federal or state laws or regulatory authorities;
- Transmission needs identified from studies carried out in connection with specific transmission service requests;

- Transmission needs associated with generator interconnection service;
- Plans and analyses developed by the Transmission Provider to provide for a reliable transmission system and to expand trading opportunities, better integrate the grid and alleviate congestion;
- Inputs from Planning Advisory Committee; and
- Inputs provided from state regulatory authorities having jurisdiction over any of the Transmission Owners and by the Organization of MISO States ("*OMS*").

Q16. PLEASE DESCRIBE MISO'S GOVERNANCE STRUCTURE AND HOW IT ALLOWS OTHERS TO PARTICIPATE IN MISO'S PLANNING PROCESSES.

A. MISO, as approved by FERC, uses a process that is open, transparent and coordinated. From an overall corporate governance perspective, MISO is managed under the direction of an independent Board of Directors, which establishes broad corporate policies and authorizes various types of transactions. The MISO Board of Directors consists of seven independent directors elected by the membership, plus the President/Chief Executive Officer of MISO. MISO Board of Directors meetings occur six times a year and are open to the public.

The Advisory Committee is important to the stakeholder governance structure at MISO. The committee reports directly to the MISO Board of Directors and contains voting representatives from a number of sectors including: state regulatory authorities, independent power producers/exempt wholesale generators, transmission owners, transmission-dependent utilities, power marketers, public consumer advocates, environmental advocates, eligible end-use customers and coordinating members. Subcommittees focused on planning, market, reliability, cost allocation, finance, and governance issues provide updates to the Advisory Committee. A copy of the MISO Entity Organization Chart is attached as **Exhibit TWV-3**.

To facilitate planning collaboration specifically, MISO has developed a number of forums in which staff, transmission owners, stakeholder entities, and policy makers participate, or contribute to, the planning process. Those forums include the Planning Advisory Committee, the Planning Subcommittee, the Interconnection Process Task Force, the Loss of Load Expectation Working Group, the Reliability Subcommittee, and the Market Subcommittee.

Specific to retail regulators, the OMS was formed in 2004 as a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the MISO. As indicated on its website, the purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions as appropriate. In connection with the integration of Entergy into MISO, an enhanced transmission planning role for the OMS has been proposed by MISO in Docket No. ER13-708 at FERC.

IV. <u>ITC'S TRANSMISSION PLANNING PROCESSES</u>

Q17. WHAT IS ITC'S OVERALL VIEW OF TRANSMISSION PLANNING?

A. ITC believes transmission planning is essential to a reliable and efficient transmission system. Effective transmission planning is the most important tool to address system limitations, which are major drivers of reliability issues and higher energy costs to customers. In order to facilitate planning, ITC employs a robust planning process that purposefully engages stakeholders and regulators, effectively and efficiently identifies issues and solutions, and implements those solutions in a cost-effective and timely manner. ITC believes it is critical that the right infrastructure solutions be implemented and the transmission system be appropriately sized to benefit end-use customers. ITC also believes in planning the transmission system through an open and transparent process, on a forward looking basis, and in a way that considers a broad range of needs. The consequences of not doing so can be detrimental as there can be a significant time between issue identification and solution implementation.

Q18. PLEASE DESCRIBE ITC'S TRANSMISSION PLANNING SYSTEM PERFORMANCE OBJECTIVES.

A. ITC plans its transmission systems to address local, state, and regional reliability needs, allow for the interconnection of generation sources, and increase the economic efficiency of the overall grid. When deficiencies are identified on the transmission system, such as inadequate capacity to meet load under contingency conditions, ITC's transmission planners develop transmission system reinforcements to address those deficiencies. ITC also contemplates transmission projects with a view to increasing the economic efficiency of the overall grid. For example, the reduction of transmission system constraints can result in more economic dispatch of generation, ultimately reducing energy costs to end-use customers. It has been our experience that these practices expand market access for customers, and also confer value through the existence of a more robust, reliable transmission grid. Finally, ITC also plans its transmission systems to address transmission needs identified in state and regional processes. A copy of each ITC operating subsidiary's "Transmission Planning Criteria" is attached as **Exhibit TWV-2**.

Q19. DOES ITC FOLLOW THE SAME APPROACH AS EAI AND THE OTHER ENTERGY OPERATING COMPANIES FOR RELIABILITY PLANNING?

A. The two businesses plan their transmission systems to meet the same NERC Reliability Standards. However, the two businesses implement the requirement to include planned (including maintenance) outages differently. Using the planning requirement to perform single contingency analysis, EAI and the other Entergy Operating Companies only consider planned outages identified in the immediate future in combination with the other single contingencies. Whereas planning at ITC's Michigan Operating Companies considers the possibility that any element may be taken out of service as a planned outage even if those outages are not yet specifically identified. This N-1-1 analysis results in a broad encompassing of the possible combinations of any single contingency occurring during any planned outage for the ITC Michigan Operating Companies. This analysis is done for load levels up to 85% of peak load with the assumption that planned outages will not generally be scheduled during times of peak usage. The N-1-1 analysis results in a system with additional flexibility to obtain facility outages for maintenance or upgrades.

Q20. PLEASE DECRIBE A TYPICAL PLANNING CYCLE AT ITC.

A. I will use the planning of the ITCT and METC transmission systems (i.e., the Michigan system) as an example in this response.

The analysis begins with the development of a load forecast. This forecast contemplates a range of future scenarios, for which the primary drivers are economic and demographic projections. This forecast is then incorporated into system models used for planning assessments of the transmission system.

In the assessments, any potential constraints on the existing system are identified. An important part of the assessment is simulating system performance under peak load conditions. Thus, these assessments are performed at load levels from the 50th and 70th percentile of the peak load forecast distribution. The 50th percentile case represents the base analysis and is what is used in the MISO planning processes. The 70th percentile forecast is used as a sensitivity analysis. This sensitivity analysis is reflective of the fact that planning for a 70th percentile peak forecast (a higher load level than the 50th percentile forecast) helps to ensure projects are developed to meet the long-term needs of the system in a cost-effective manner. The planning process at ITC entails the simulation of all of the various contingencies as required by the regional and local planning criteria (at a baseline 50th percentile peak load forecast and a higher 70th percentile peak forecast case). While the peak load conditions are an important part of the assessments, it is also important to assess expected system performance under off-peak load conditions.

In the assessments for Michigan, the system is divided into geographic areas that share common growth patterns, facilities, and system issues. Along with assessing the system using a 70th percentile peak load forecast as a sensitivity, the system is also tested by considering various power transfers across the system from west to east, east to west, north to south and south to north. These sensitivities further help ensure that projects are developed so as to allow for a range of possible future scenarios. The annual near-term and long-term assessments describe the nature of the system problems identified, the limiting elements giving rise to the problems, the possible impact of the issues on system operations, and, ultimately, proposed solutions. The proposed solutions are derived by ITC's transmission planners through their knowledge of the system, communications with ITC's operations department, communications with regulators and stakeholders and general engineering expertise.

Results that indicate a need for new infrastructure in the near term, or that would require multiple years for implementation, are then submitted to the MISO MTEP process for inclusion in the MTEP as Appendix A projects (meaning approval is requested at the conclusion of the MTEP cycle).

As described in further detail elsewhere in my testimony, this planning cycle is subject to the MISO and ITC stakeholder processes where information is both solicited and shared.

Q21. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY ONE OF ITC'S OBJECTIVES IS TO PLAN THE SYSTEM TO INCREASE THE ECONOMIC EFFICIENCY OF THE OVERALL GRID.

A. As mentioned above, in addition to obtaining compliance with NERC's Reliability Standards, ITC's planning process also considers the economic efficiencies that may be realized by planning, and ultimately constructing, additional transmission. For example, when it is found to be economically justified, ITC develops projects to reduce costs associated with generation dispatch patterns that are more costly than what could be achieved in the absence of certain transmission system constraints.

Q22. WHY IS ANALYZING SYSTEM CONSTRAINTS IMPORTANT FOR ENSURING SYSTEM RELIABILITY?

A. A transmission constraint arises when an element or part of the system is at a limit and cannot reliably handle more power flow. Because of the transmission constraint, no more power can be allowed to flow through that constraint. Consequently, the element or part of the system that is limited by the constraint can no longer meet incremental needs by utilizing resources in the portion of the system that is not bound by the constraint. This means that load affected by a constraint is limited to a smaller pool of resources, and thus the load that is on the limiting side of the constraint is at an increased risk for a power outage due to a generator or transmission line failure. Likewise, in a case where all the generation resources bound by the constraint are already deployed, it may not be possible to serve additional load in this portion of the system. In other words, there are fewer options available to compensate for the effects of the loss of a facility or increased power demand in the area of the system for which the constraint is active. All else being equal, the removal of transmission constraints makes it less probable that load loss (power outage) will occur.

Q23. CAN SYSTEM CONSTRAINTS ALSO HAVE ECONOMIC IMPLICATIONS?

A. Yes. Transmission system constraints can also have undesired economic impacts because system limitations may decrease overall grid efficiency. For example, by preventing the most economic dispatch of generation to be used to serve load, a system limitation may lead to an increase in total cost of energy. In other words, the transmission constraint prevents a dispatch pattern that could provide lower costs. Remedying a constrained transmission system can allow the lower cost generation to serve load when needed, thereby resulting in reduced purchased power costs to end-use customers.

Q24. WHAT OPTIONS ARE GENERALLY AVAILABLE TO MITIGATE TRANSMISSION CONSTRAINTS?

A. In the short-term, flow through constraints must be managed to adhere to system limitations through methodologies such as re-dispatch or, in extreme cases, load shedding. Some constraints are the result of temporary conditions on the system and can be mitigated through returning the system to its more permanent configuration. Those temporary conditions may be the result of an unusual or unexpected condition such as the unavailability of parts of the transmission system or generators in the vicinity of the constraints. While temporary conditions are important and should be assessed, ITC planners typically are more interested in recurring constraints. In the long-term, transmission constraints (which, as described above, can cause reliability concerns and increased economic costs) can be alleviated by: (1) reducing electricity demand in the area limited by the constraint through energy efficiency and demand-side management programs; (2) building more generation capacity in the area limited by the constraint; (3) building additional transmission capacity to either alleviate the constraint or provide another transmission path to enable more power to get to the area for which the constraint is limiting; or (4) continuing to rely on the short-term operating practices if other more cost-effective solutions are not available.

Q25. DOES ITC'S PLANNING PROCESS CONSIDER NON-TRANSMISSION SOLUTIONS TO MITIGATE TRANSMISSION CONSTRAINTS?

A. As an independent transmission-only entity, ITC provides transmission solutions to mitigate transmission constraints. However, non-transmission solutions (e.g. demand side management and reconfiguration of load on the lower voltage systems) may be identified by others and considered in MISO's open and transparent planning forum and therefore in ITC's planning process.

Q26. IN YOUR OPINION, HOW WELL DO THE ITC AND MISO PLANNING PROCESSES WORK TOGETHER?

A. These processes work well together and are integrated appropriately. They also bring together a good aggregation of core competencies. MISO is not designed to have the in-depth knowledge, data, and experience that local Transmission Owners possess about their own systems. This expertise is a key driver behind each project proposed by Transmission Owners. MISO, however, is in a better position to coordinate and facilitate the extensive MTEP processes.

Q27. PLEASE PROVIDE EXAMPLES OF WHERE ITC'S TRANSMISSION PLANNING BROUGHT CUSTOMER BENEFITS.

A. The Jewell to Spokane Project, which is located in southeast Michigan, is a good example of how a relatively small investment in transmission resulted in significant cost savings to customers by relieving transmission constraints. The project consisted of: (1) a new 13-mile long 230 kV transmission circuit; (2) a 345-230 kV transformer installed at Jewell; (3) a 230-120 kV transformer installed at Spokane, and (4) approximately 2.9 miles of 1431 ACSR conductor installed from a tower position to Jewell Station thus creating a new Adams-Jewell 120 kV circuit. The Project had a one-time cost of $10.2 million. It was determined that this investment was reasonable in light of the economic efficiencies this project brought to the overall grid. The economic benefits metrics used in this analysis resulted in estimated annual net benefits of over $60 million.

Likewise, ITCMW is in the process of constructing a new 80-mile 345 kV line in Iowa intended to improve reliability in eastern Iowa and improve market efficiency by reducing transmission congestion. When completed, the Salem-Hazelton transmission line will connect ITCMW's Hazleton Transmission Substation in Buchanan County, Iowa to ITCMW's Salem Transmission

Substation in Dubuque County, Iowa. The Salem-Hazleton Line was modeled in 2006 as a solution to transmission constraints in eastern Iowa in MISO's Eastern Iowa Study. MISO found that the construction of the Salem-Hazelton line would reduce annual load and production costs by approximately $108 million. The total capital cost of the line is currently projected to be $123 million, which will be collected over the 60-year depreciable life of the line. The need for the line was recognized for several years prior to 2006 but was not built until after ITC's acquisition of ITCMW.

Q28. CAN YOU PROVIDE AN EXAMPLE OF HOW ITC ALSO PLANS ITS TRANSMISSION SYSTEMS TO ADDRESS TRANSMISSION NEEDS IDENTIFIED IN REGIONAL AND STATE PLANNING PROCESSES?

A. Yes. For example, ITCT is making a significant investment in Michigan's high voltage electric grid by developing a new 140-mile transmission line and four new substations which, taken together, will help increase transmission system reliability, reduce system congestion, provide more efficient transmission of energy and serve as a "backbone" for future interconnection of new generation sources. MISO approved the Thumb Loop Project as the first Multi-Value Project ("***MVP***") with regional benefits beyond just the accessing of new renewable generation. ITCT has received siting approval for this project and currently is undertaking construction activities.

In addition, on December 8, 2011, ITC received approval from MISO to construct portions of four other MVPs. The portions of these projects that ITC will build, own, and operate will be located in parts of Iowa, Minnesota, and Wisconsin.

Finally, ITCMW has been upgrading the existing 34.5 kV system to a 69 kV system in Iowa. The 34.5 kV lines primarily serve rural Iowa and the age, condition, and limited capacity on these lines limits economic development in rural communities. ITCMW is committed to upgrading the 34.5 kV system so portions of rural Iowa can effectively connect ethanol and other biodiesel plants which typically locate in these areas, thus advancing state and local economic development.

Q29. DOES ITC HAVE ITS OWN STAKEHOLDER PROCESSES FOR SOLICITING AND SHARING PLANNING INFORMATION?

A. Yes, ITC considers its stakeholder engagement to be as important as the aforementioned ITC system performance objectives for planning. As such, ITC also has its own regulator and stakeholder processes for planning purposes in addition to the MISO stakeholder processes.

For example, ITCT, METC and ITCMW hold meetings with regulators and stakeholders where ITC presents its views on system planning, detailed descriptions of capital plans, load forecasts, rates, and a general review of the regulatory environment. With respect to planning, these meetings are intended to give stakeholders details of ITC's project plans, keep them apprised as to what ITC will be submitting for MTEP consideration, keep them informed on the need each project is intended to address, and inform them of emerging planning issues. The meetings also are used to solicit feedback from regulators and stakeholders including retail regulators, large retail industrial customers connected at transmission level voltages, electric cooperatives, municipal utilities, community leaders, marketers, generators, load serving entities, business groups, legislators, and energy advocacy groups.

ITC also makes an extra effort to keep regulators and policy makers informed and aware of emerging planning issues. For example, ITC meets separately with regulators to discuss its plans for transmission development, to share ideas about transmission issues, and to gather input from the regulators' perspective. In fact, as described by ITC witness Mr. Thomas Wrenbeck, ITC has dedicated individuals in each jurisdiction responsible for meeting the needs of regulators, including soliciting input and providing information on transmission plans.

Likewise, ITC also has a dedicated "Stakeholders Relations" group. Among its other duties, this group works with ITC planners to facilitate one-on-one meetings with affected customers, stakeholders, and regulators. ITC witness Mr. Thomas Wrenbeck provides a more detailed description of this group in his testimony.

Further, ITC's planning group participates in industry forums established to discuss and consider transmission needs. For example, the State of Michigan initiated a "Capacity Needs Forum," under which I chaired the Transmission and Distribution Group, where meetings were held with transmission-dependent utilities and state regulators to discuss transmission and distribution issues.

Q30. BASED ON THE COLLABORATIVE PROCESSES DESCRIBED ABOVE, HAS ITC BEEN SUCCESSFUL IN CONSIDERING THE NEEDS OF INTERCONNECTION CUSTOMERS?

Yes. ITC works to interconnect new customers and generation efficiently, economically, in a timely manner, and to design and plan transmission that meets customer needs. Given ITC's sole focus on transmission, its operating subsidiaries have the time and the resources to sit down with customers or generators wishing to interconnect and walk them through the MISO interconnection process. In part, based on these practices, ITC has had significant success in interconnecting new generators to its transmission systems. ITCMW alone has interconnected over 16 new generators in the last four years, adding approximately 2,150 MW of energy production capacity to the grid.

Q31. HOW DOES ITC ENSURE THAT THE ITC PLANNING PROCESSES RESULT IN PRUDENT TRANSMISSION PROJECTS?

A. ITC actively participates in the MTEP process, which is a FERC-sanctioned process for reviewing and approving projects. The MISO planning forum is a transparent and participatory process, which, as described above, allows for ample opportunity for input from regulators and stakeholders including transmission developers and customers. Within this process, anyone is free to introduce alternatives to a proposed transmission project. MISO conducts its own review of proposed projects and will inform the sponsoring operating company and involved stakeholders of any concerns. Projects are evaluated based on modeled reliability improvements, estimated costs, performance using MISO-specified economic metrics, and assessed ability to meet public policy objectives. MISO also determines whether correcting a constraint in one area of its region could impact transmission congestion in another area. In some cases, MISO may propose another alternative for improving reliability or relieving a constraint that it believes is more economic or effective. When differences arise, the transmission planners at the MISO member company and the planners at MISO often will work together to develop a collaborative solution to an identified problem. If a solution cannot be agreed upon, MISO makes the final determination as to what project should be proposed for inclusion in Appendix A to be reviewed and voted on by the MISO Board of Directors.

As described above, ITC also meets regularly with affected stakeholders and regulators. This provides another opportunity to identify system needs and discuss optimal solutions for those needs, ensuring efficient coordination between the transmission and distribution systems. Moreover, almost all jurisdictions have siting processes for infrastructure such as transmission. This provides yet another forum and means to discuss ITC's proposed projects

Further, given ITC's commitment to professional integrity, as well as ITC's status as a FERC-regulated utility, it is incumbent upon ITC to advance only prudent projects. ITC's reputation and credibility would be seriously harmed if it proposed inappropriate or imprudent projects. As testified to by ITC witness Mr. Joseph Welch, ITC is unique in the industry as an independent, transmission-only utility. The merits of the independent transmission business model and the future role it will play in the U.S. utility industry rests very much on the company's performance and the extent to which ITC's business model is shown to be desirable for customers.

Finally, ITC has grown its business, in part, by acquiring other transmission systems from existing vertically integrated utilities that ultimately become its customers and stakeholders. If ITC developed a poor reputation due to its unwillingness to comply with the wishes of affected regulators and stakeholders in its current jurisdictions, growth by acquisition would be impossible.

V. TRANSMISSION PLANNING ON THE ENTERGY SYSTEM POST-TRANSACTION

Q32. WILL THE NEW ITC OPERATING COMPANIES PARTICIPATE IN THE MISO PLANNING PROCESS IF THE TRANSACTION IS APPROVED?

A. Yes. Participation in the MTEP process assures that projects identified by the New ITC Operating Companies[6] will be integrated and consistent with the plans of other transmission entities within the region. Further, it ensures that projects are consistent with the needs of the existing and emerging energy markets in the region served by EAI and the other Energy Operating Companies. It also provides

[6] The term "New ITC Operating Companies" refers to the newly created operating companies that will own electric transmission assets as part of the ITC Holdings Corp. corporate structure. The New ITC Operating Companies will be a direct subsidiary of ITC Midsouth LLC, which in turn will be a direct subsidiary of ITC Holdings Corp.

a forum for those projects to be vetted in an open and transparent process inclusive of interested stakeholders.

Q33. YOU HAVE DISCUSSED HOW ITC INTERACTS WITH THE OMS AS PART OF ITC'S PLANNING EFFORTS. CAN YOU PLEASE DESCRIBE HOW THE NEW ITC OPERATING COMPANY WOULD EXPECT TO INTERACT WITH THE E-RSC IN ITC'S PLANNING PROCESS AFTER THE TRANSACTION?

A. ITC witness Mr. Joseph Welch addresses this issue directly, but my understanding is that ITC has committed to support retention of the ERSC's existing authority over cost allocation and the construction of transmission upgrades for the five year transition period after EAI and the other Entergy Operating Companies join MISO.

Q34. DO THE ENTERGY OPERATING COMPANIES HAVE AN ESTABLISHED EXPANSION PLAN FOR THE TRANSMISSION SYSTEM?

A. Yes. The Entergy OASIS website posts various documents relating to transmission plans for the Entergy Region. One of these documents is the current Construction Plan ("*CP*"). The CP also considers the needs of the transmission system over a five year period. The Entergy CP may contain more than reliability-driven projects. The latter portion of this document is the Year 6 through 10 projects, referred to as the Horizon Projects ("*HP*").

Q35. HAVE YOU REVIEWED THE PROJECTS INCLUDED IN THE CURRENT ENTERGY CP?

A. Yes. ITC will consider the projects in the current Entergy CP. As ITC witness Mr. Joseph Welch explains, ITC would generally expect to complete any in-progress transmission projects, as well as follow through on near term planned projects in order to make sure that none of the New ITC Operating Companies fail to meet any reliability requirements. Likewise, Mr. Welch explains that ITC would not want to disrupt any established project schedules, or fail to honor any then-existing contractual obligations.

Q36. WOULD THE NEW ITC OPERATING COMPANIES LOOK BEYOND THE CURRENT PROJECTS IDENTIFIED IN THE CURRENT ENTERGY CP?

A. Yes. Once the Transaction closes, the New ITC Operating Companies will engage regulators and stakeholders through processes similar to those described above, to help us determine the future needs of the transmission system in the Entergy footprint.

Q37. FROM A TRANSMISSION PLANNING PERSPECTIVE, HOW WOULD THE TRANSACTION ENHANCE CUSTOMER BENEFITS BEYOND WHAT COULD BE ACHIEVED THROUGH MISO MEMBERSHIP?

A. MISO has been very successful in implementing FERC's open access policies in its current footprint. This success, coupled with the growth in competitive wholesale markets, has led to improvements in economic dispatch of the grid by increased usage of the grid at a time when more investment in, and expansion of, the grid is critically necessary. As the Entergy Operating Companies seek to move into MISO, with its efficient, transparent, and successful regional energy market, the demands placed on the transmission system for the Entergy Region likely will increase, along with market transactions. MISO has no ability or mandate to undertake the construction of transmission facilities to meet the demands of the wholesale market. Instead, the member Transmission Owners must plan, attract the necessary capital, and build the transmission facilities approved as part of the MTEP. Further, as I previously testified, MISO generally uses a bottom-up stakeholder-driven process in which the Transmission Owners address deficiencies and explore the opportunities on their own systems. Transmission Owners identity alternatives to solve any deficiencies and capture economic opportunities by recommending projects to the MISO for inclusion in the MTEP. Typically, if a project is not brought forward by a Transmission Owner, regulator or other stakeholder, it is less likely to have the necessary study and development required to be considered in the MTEP planning process.

ITC's singular focus on maintaining, operating, and enhancing the robustness of the transmission grid is essential during this time when the Entergy Operating Companies are planning a move into the MISO market and use of the grid for market transactions is likely to increase. ITC has the expertise, resources, and capital to plan and construct the needed investment. Moreover, ITC's independence assures that market participants, regulators and stakeholders have confidence in how the system is planned and that an open and transparent planning process is utilized.

Likewise, ITC has no internal competition for capital across functions or operating companies, so the New ITC Operating Companies will have capital available to make the necessary investment. ITC's regional approach to transmission planning will also facilitate enhanced deliverability of generation throughout the region to provide economic sources of energy for its customers or advance policy goals of the retail jurisdictions it serves. In that regard, the New ITC Operating Companies will plan and build transmission to improve the overall efficiency of the market and to enhance economic dispatch at the RTO level.

Q38. DO YOU ANTICIPATE THAT THE ORGANIZATIONAL STRUCTURE FOR ITC'S PLANNING GROUP WILL CHANGE SUBSTANTIALLY IF THIS TRANSACTION IS APPROVED?

A. No, I don't anticipate that the organizational structure will change substantially. We are still in the process of determining the post-transaction organizational design. However, I anticipate that I will continue to report to the Executive Vice President and Chief Operating Officer, that the Planning functions for the newly created operating companies will also report to a high ranking executive officer (likely Mr. Richard Riley), and that the overall positions and functions will remain the same (*i.e*, we still will have Managers, Principal Engineers, Senior Engineers, Engineers, Associate Engineers, Economic Analysts, Programming Analysts, and Engineering Technicians functions). Importantly, as described in ITC witness Mr. Jon Jipping's testimony, ITC's New Operating Companies will employ an organizational structure that augments the performance accountability of a traditional line reporting structure with corporate-level governance and oversight for the Operations, Planning, Engineering, and Asset Management functions.

Q39. WILL END-USE CUSTOMERS BENEFIT FROM ITC'S APPROACH TO TRANSMISSION PLANNING IF THIS TRANSACTION IS APPROVED?

A. Yes. For example, because ITC is independent and has no generation affiliations with competitive interests, developers are comfortable sharing their generation plans with ITC. This open communication was key to the transmission planning that resulted in the Thumb Loop and GPE projects described above. ITC believes its GPE project, based on a regional approach to planning, helped advance the regional planning process and ultimately resulted in several MVPs being submitted to MISO for consideration.

Likewise, ITC's independent business model has allowed it to successfully participate in statewide and federal initiatives to consider transmission development. For example, in Michigan, ITC was an active participant in the Michigan Wind Working Group, which served as a technical committee for the Michigan Public Service Commission's Michigan Renewable Energy Program. Goals of the Wind Working Group included continuing efforts to inform and educate the public, farmers, businesses, institutions, and political leaders about wind energy opportunities as well as providing forums and assistance to foster wind energy development. In years 2008 through 2009, the group considered the transmission needs for various locations of wind generation across Michigan, which ultimately led to the identification of Michigan's Thumb Loop project.

Similarly, when the carbon dioxide emissions standards were being considered by the Environmental Protection Agency, at the request of various stakeholders, ITC's independence allowed it to lead a study effort that considered the transmission needs in Michigan associated with various generation requirement scenarios driven by the new standards.

The processes ITC will use to value potential upgrades are intended to find and appropriately size beneficial transmission investments in order to, amongst other things:

- enhance customer reliability by improving the transmission system's ability to serve load through upgrades that increase thermal capacity and keep the system within acceptable voltage, stability and short circuit limits as well as improve storm hardening and create additional paths for generation to reach load;
- increase economic efficiency of the overall grid such as
  - reducing energy costs by removing transmission constraints that cause congestion and must-run commitments, particularly during challenging load, outage, and market conditions;
  - reducing resource adequacy and operating reserve costs by decreasing system congestion and reducing the need for isolated areas to hold additional reserves and by broadening the pool of generating capacity that is accessible to meet resource adequacy requirements;
  - reducing transmission line losses, resulting in less generation being needed to serve peak load;
  - facilitating the development of competitive wholesale energy markets by increasing access to competing generation sources;
- improve optionality for utilities at a time of significant uncertainty with regards to new environmental regulations potentially impacting fossil-fuel-fired generation; and
- ensure adequate transmission capacity to advance state and federal policy objectives.

Q40. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

STATE OF Michigan)
) SS.
COUNTY OF Oakland)

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	)	File No. EO-2013-0396

AFFIDAVIT OF THOMAS W. VITEZ

COMES NOW Thomas W. Vitez, of lawful age, sound of mind and being first duly sworn, deposes and states:

1. My name is Thomas W. Vitez; I am Vice President of Planning of ITC Holdings Corp.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony in the above-referenced case.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge, information and belief.

Thom W. Vitez
Thomas W. Vitez

SUBSCRIBED AND SWORN to before me, a Notary Public, this 24th day of APRIL, 2013.

Linda E. Sweeney
Notary Public

My Commission Expires:
(SEAL)

LINDA E. SWEENEY
NOTARY PUBLIC - STATE OF MICHIGAN
COUNTY OF WAYNE
My Commission Expires May 28, 2015
Acting in the County of OAKLAND

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	))))))))	File No. EO-2013-0396

EXHIBIT TWV-1

ITC'S Planning Department Chart

August 24, 2012

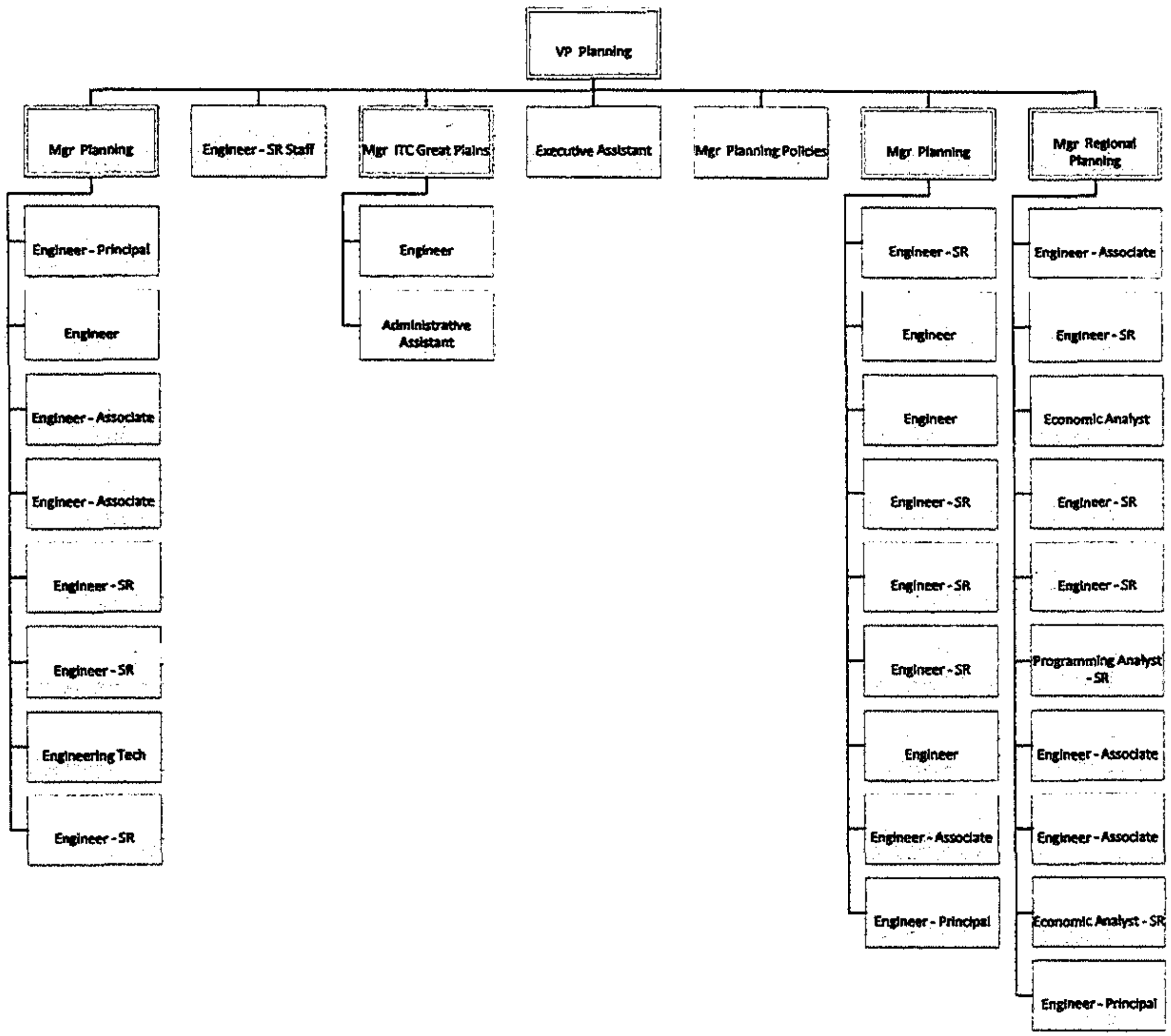

EXHIBIT TWV 01

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application	)	
of Entergy Arkansas, Inc., Mid South	)	
TransCo LLC, Transmission Company	)	
Arkansas, LLC and ITC Midsouth LLC	)	File No. EO-2013-0396
for Approval of Transfer of Assets and	)	
Certificate of Convenience and Necessity,	)	
and Merger and, in connection therewith,	)	
Certain Other Related Transactions	)	

EXHIBIT TWV-2

Transmission Planning Criteria

ITC MIDWEST

TRANSMISSION PLANNING CRITERIA

100 kV AND ABOVE[1]

May, 2012

[1] This manual defines and explains the current planning criteria and will be reviewed and updated as required. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economic or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are <u>guidelines</u> to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

TABLE OF CONTENTS

1 Goal

This document describes the criteria to be used in assessing the reliability of the ITC Midwest transmission (100 kV and above[2]) system. This transmission planning criteria is intended to result in an ITC Midwest transmission system that economically and reliably allows our transmission system customers to serve load from generation of choice.

2 NERC & MRO Reliability Criteria

ITC Midwest adheres to the NERC Reliability Standards and the MRO Standards.

In Table 1 of the NERC TPL Standards (TPL-001-0, TPL-002-0, TPL-003-0 & TPL-004-0), four categories of conditions have been defined as follows (SLG is single line ground and 3φ is three phase):

[2] For these criteria, this includes transformers with a low side voltage rating above 100 kV.

Table 1 – Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Elements(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line to Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator	Yes	No[b]	No
	2. Transmission Circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
	Loss of an Element without Fault	Yes	No[b]	No
	Single Pole Block, Normal Clearing[d]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[d]: 1. Bus Section	Yes	Planned/Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/Controlled[c]	No
	SLG or 3Ø Fault, with Normal Clearing[d], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[d]: 3. Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing. 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[d]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/ Controlled[c]	No
	9. Bus Section	Yes	Planned/ Controlled[c]	No

D[d] Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences - May involve substantial loss of customer demand and generation in a widespread area or areas. - Portions of all of the interconnected systems may or may not achieve a new, stable operating point. - Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal fault)	
	6. Loss of towerline with three or more circuits	
	7. All transmission lines on a common right of way	
	8. Loss of a substation (one voltage level plus transformers)	
	9. Loss of a switching station (one voltage level plus transformers)	
	10. Loss of all generating units at a station	
	11. Loss of a large load or major load center	
	12. Failure of a fully redundant Special Protection Scheme (or Remedial Action Scheme) to operate when required.	
	13. Operation, partial operation, or misoperation of a fully redundant Special Protection Scheme (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate.	
	14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

The following requirements are specified in the MRO Standard TPL-503-MRO-01 System Performance.

Table 2 – MRO System Performance Table[1]

NERC Categories	Transient Voltage Deviation Limits	Rotor Angle Oscillation Damping Ratio Limits
A	Nothing in addition to NERC Requirements	
B (See Notes 2 and 6)	Minimum 0.70 p.u. at any bus. (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
C (See Notes 2, 3, and 6)	Minimum 0.70 p.u. at any bus. (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
D (See Notes 2, 3, and 4)	Nothing in addition to NERC Requirements	

Notes:

1. The MRO System Performance Table including the notes applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to the end of the allowed readjustment period as described in MRO Regional Reliability Standard TPL-503-MRO-01_R1.4).

2. The following summarizes the automatic and manual readjustments that are permissible for all NERC Category B disturbances.

   A. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units.

   B. Capacitor and reactor switching - The number of capacitors and reactors which may be switched is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period.

   C. Adjustment of Load Tap Changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the allowed readjustment period.

   D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.

The following requirements are specified in the MRO Standard TPL-503-MRO-01 System Performance.

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   C. Adjustment of Load Tap Changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the allowed readjustment period.

   D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.

E. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.

F. Generation rejection to the extent possible within the allowed readjustment period. Shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.

G. Transmission reconfiguration - Automatic and operator initiated tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.

H. Automatic or manual tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Point-to-Point Transmission Service to the extent possible within the allowed readjustment period. Curtailment of Firm Transmission Service within the readjustment period is permitted only to prepare for the next contingency.

3. The following additional readjustment may be considered for all NERC Category C contingencies.

   A. Automatic or manual tripping of firm Network or Native Load or curtailment of or predetermined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

4. The following additional readjustments may be considered for all NERC Category D contingencies.

   A. Planned and/or controlled islanding - Automatic underfrequency load shedding, as specified in NERC PRC-006-0, is permitted to arrest declining frequency and generation rejection is permitted to arrest increasing frequency in order to assure continued operation within the resulting islands.

   B. Automatic undervoltage load shedding is permissible to arrest declining voltages and prevent widespread voltage collapse.

5. The voltage of 0.7 per unit is the point at which load dropping begins to occur due to motor contactors dropping out and induction motors stalling and also the point where sensitive (power electronics) begin to drop out.

6. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category B disturbances, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category C disturbances, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

7. Damping is required during the initial transient period following the disturbance (up to 20 seconds). The machine rotor angle damping ratio is determined by appropriate modal analysis (for example, Prony analysis). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.90 or the damping factor must be greater than 10%. (The SPPR criteria were chosen to define positive rotor angle damping for study purposes in MAPP. The Rotor Angle Oscillation Damping Ratio Limits were derived from the SPPR criteria.)

3 Introduction to ITC Midwest Planning Criteria

This planning criteria manual sets down the planning guidelines used to determine system needs and justify modifications to the transmission system. This manual defines and explains the current planning criteria and will be reviewed and updated as required.

The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economical or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

Planning for the transmission system is intended to provide a network capable of transmitting power between generating sources and loads. The ITC Midwest system is utilized by various generation sources and load throughout the Eastern Interconnection via Network Integration Transmission Service or various other forms of Transmission Service. The implementation of the projects and operating solutions identified by application of this planning criteria shall result in a ITC Midwest system for which the probability of initiating cascading failures is very low. The system should also provide operating flexibility including, but not limited to, allowing maintenance outages. Non-consequential loss of load may be tolerated for extreme contingencies.

In meeting the above objectives, the planning engineer must recognize the present state-of-the-art with regard to equipment, construction practices, scheduling and the practical needs of operating the electrical system. It must be recognized that thermal overloading can shorten the equipment life and lead to sudden failures and that abnormal voltages can also cause equipment failures and/or voltage sensitive equipment to be affected. The planning engineer also needs to be cognizant of intangible considerations, such as the social and political implications of his work as well as visual and ecological effects. In particular, one social implication that the planning engineer needs to consider is the social benefit of the loads being able to access the most economical generation available. Many of these elements cannot be guided by exact rules and the engineer's judgment must be factored into the proposed projects. In summary, the material gathered in this manual is intended to provide basic system planning guidelines. The planning engineer, however, must still apply ingenuity, experience and judgment in order to develop projects which lead to an economic and reliable power system and supports the access to economical generation. Where judgment is used, it should be recognized as such and documented so as to be part of the record for future planning.

4 Thermal Loading and Voltage Planning Criteria

4.1 Description

The transmission system is used to transmit power and energy from interconnected generation plants to interconnected loads. Some of the generation and load that utilize the ITC Midwest system are not directly interconnected with the ITC Midwest system but are part of the larger interconnected grid and utilize the ITC Midwest system through its ties with neighboring systems.

4.2 Design Considerations

The ITC Midwest system should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 3 – ITC Midwest Planning Criteria for allowable load loss by contingency type). Planning studies are to be carried out for projected annual peak system load conditions, but the planning criteria also holds for load levels less than annual peak. Additionally, the planning criteria evaluates projected shutdown conditions (a single element shutdown plus a single element forced out) at a lower load level.

The ITC Midwest system will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the transmission system. These needs may be communicated by reservations on the transmission system including network service or through other mechanisms.

Studies to determine transmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation.

MRO models are typically used to evaluate system performance for compliance with the NERC TPL Standards. Details of model development can be found in the MRO Model Building Manual.

For those conditions and events that do not meet the performance requirements of Table 3 – ITC Midwest Planning Criteria, corrective plans involving capital projects will be developed. Operating guides will only be used as interim solutions, prior to completion of system upgrades.

4.3 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the planning criteria are violated.

- Relocation of ITC Midwest facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Repair, rebuild or replacement of facilities needed to provide acceptable reliability. This includes facilities which due to design no longer provides acceptable reliability and/or facilities in which normal maintenance is not effective to maintain reliability due to the overall condition of the facilities.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators must be considered when developing projects. The goal is to develop a robust transmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

4.4 Voltage and Facility Loading Criteria

4.4.1 Generally Applicable Criteria

Table 3 – ITC Midwest Planning Criteria

Description	NERC Category	Allowable Load Loss	Ratings Used [c]	Load Level [h]	Minimum Voltage [b,e,f]	Maximum Voltage [b,e,f]
System Normal	A	none	normal	100%	95%	105% [k]
Single Generator	B1	none	emergency	100%	93% [j]	110% [j,l]
Single UG Cable	B2	none [a]	emergency	100%	93% [j]	110% [j,l]
Single OH Line	B2	none [a]	emergency	100%	93% [j]	110% [j,l]
Single Transformer	B3	none [a]	emergency	100%	93% [j]	110% [j,l]
Bus Section	C1	none [a,g]	emergency	100%	93% [j]	110% [j,l]
Circuit Breaker	C2	none [a,g]	emergency	100%	93% [j]	110% [j,l]
Shutdown + Contingency	B1, B2 or B3	none [a,g]	emergency	70%	93%	110% [j,l]
Double Circuit Tower [i]	C5	none [a,g]	emergency	100%	93% [j]	110% [j,l]
Double Contingencies [d]						
1. After First Contingency (Prior to System Re-Adjustment)	C3	none [a]	emergency	100%	93%	110% [f]
2. After First Contingency (After System Re-Adjustment)	C3	none [a]	normal	100%	95%	105% [k]
3. After Second Contingency (Prior to System Re-Adjustment)	C3	none [a,g]	emergency	100%	90%	110% [f]
4. After Second Contingency (After System Re-Adjustment)	C3	none [a,g]	emergency	100%	93%	105% [k]
Extreme Contingencies [d]	D	no cascading	emergency	100%	no cascading	no cascading

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.

b) System Normal voltage limits represent pre-contingent system voltage limits (SOLs) under normal system conditions. Post-contingent system voltage limits (SOLs) are emergency voltage limits under abnormal or emergency system conditions.

c) The normal and emergency ratings are developed in accordance with PWR-601 ITC Midwest Equipment Thermal Load Ratings. The normal and emergency rating may be the same.

d) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. Action must be taken within 30 minutes of initial disturbance. The loss of two elements without time between for operator action is interpreted by ITC Midwest to be more severe than category C and is treated like an extreme contingency.

e) All Nuclear Plant Interface Requirements (NPIRs) in the ITCMW footprint shall be monitored and upheld. The normal and contingent DAEC 161 kV voltage requirement is a minimum of 99.2% and a maximum of 104.14%.

f) The voltage limits listed are steady state voltage limits. Voltage control devices (e.g., tap changers, switched shunts, and phase shifting transformers) should be set to control during the analysis.

g) There may be some load loss to a defined pocket of load as a direct consequence of the system topology.

h) The Load Level shown is the maximum load level (in percent of the system peak) to which this part of the criteria should be applied. It is also valid at any load level less than that shown.

i) Any two circuits of a multiple circuit towerline excludes transmission circuits where multiple circuit towers are used over a cumulative distance of 1 mile or less in length.

j) Voltage must be restorable to the System Normal range after system adjustments. Action must be taken within 30 minutes of disturbance.

k) 107% for 115 kV buses.

l) System studies should monitor at the System Normal Maximum Voltage.

Tests should be applied as appropriate to examine the system's susceptibility to voltage collapse. The system should be monitored for voltage deviations greater than 5%. The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) may be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

When contingencies result in buses being isolated from all sources of the same or higher voltage, it is not considered a violation of the planning criteria for voltages on the isolated buses to be outside the parameters of Table 3 - ITC Midwest Planning Criteria, provided that the voltages on the underlying system are within acceptable limits.

Projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 3 - ITC Midwest Planning Criteria for any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition. Where projects are proposed for additional dispatch scenarios, their use will be justified and documented.

4.4.2 Shutdown Conditions

For load levels at or below the maximum planned for load level with shutdowns (see Table 3 - ITC Midwest Planning Criteria) it is expected that the shutdown of a single component would result in element loadings and system voltage within normal ranges. Further, it is expected that contingent loss of a component on top of the shutdown of a single component would result in element loadings and system voltages within emergency ranges.

There must be a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement. Planning studies must therefore evaluate the system under shutdown conditions using the maximum planned load level with shutdowns (see Table 3 - ITC Midwest Planning Criteria). The maximum planned for load level with shutdowns should periodically be re-evaluated to ensure that the application of that criterion is consistent with the requirement of having a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement.

MRO summer off-peak models are typically used to evaluate system performance for shutdown conditions. MRO defines summer off-peak (shoulder) load as 70% of summer peak load conditions.

4.4.3 Single Contingency Followed by Operator Action Followed by Another Single Contingency

The forced outage of a single generator, transmission circuit (or portion thereof) or transformer followed by operator interaction and then followed by another forced outage of a single generator, transmission circuit (or portion thereof) or transformer is considered to be a NERC Category C event. For these events, NERC Reliability Standard TPL-003-0 requires all remaining system elements to be within applicable thermal and voltage limits and also allows load shedding. ITC Midwest has separated the allowable load shedding in the Standard into two categories. In the first category, load is shed via operator-initiated actions following the loss of two elements in order to keep the loading of system elements within established longer-term emergency ratings and system voltages within established limits. Following the loss of two elements and prior to load shed, the loading of system elements must be within established short-term emergency ratings. Since ITC Midwest does not use short-term emergency ratings, this type of load shedding is not allowed. In the second category, supply to a defined pocket of load is lost as the direct consequence of the system topology. An example of the second category would be a substation which serves distribution load and has only two supplies. The concurrent outage of both supplies will result in the load at that substation being dropped. This type of load shedding is allowed.

4.4.5 NERC Category D – Extreme Event

The ITC Midwest system will be evaluated using a number of extreme contingencies that are judged by Planning to be critical. It is not expected that it will be possible to evaluate all possible facility outages that fall into NERC Category D. These events may involve substantial load and generation loss in a widespread area. These critical category D contingencies should not result in cascading outages beyond the ITC Midwest system area and any immediately adjacent areas.

5 Stability Criteria

Stability is the ability of a generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 3 – ITC Midwest Planning Criteria.

Generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on two transmission circuits on a multiple circuit tower with normal[b] clearing.
3. A single phase-to-ground fault at the most critical location[a] with delayed[c] clearing.

4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a three phase-to-ground fault at the most critical location[a] with normal[b] clearing.
5. A single phase-to-ground internal breaker fault with normal[b] clearing.
6. Where single pole tripping is enabled, single phase-to-ground faults on the transmission circuit with successful reclosing, and unsuccessful reclosing due to permanent single phase-to-ground faults with normal[b] clearing.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

Performance during and after the disturbance shall meet the requirements of the NERC TPL standard's Table 1 – Transmission System Standards – Normal and Emergency Conditions, and the MRO System Performance Table of MRO Standard TPL-503-MRO-01.

A one-cycle[3] safety margin must be added to the actual or planned fault clearing time.

6 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within specified momentary and/or interrupting ratings for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

7 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

[3] The basis for the one-cycle safety margin is that it has historically been used by MAPP and is listed in the MAPP Members Reliability Criteria and Study Procedures Manual dated April 2009, and the MISO Transmission Planning Business Practices Manual dated 11-20-10.

8 Voltage Deviation Standards

8.1 Capacitor Switching

The maximum percent change (step-change) in system voltage under normal system conditions shall be 3% when sizing capacitor banks.

8.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for a single generator tripping.

8.3 Loss of an Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for a single transmission element tripping.

9 Coordination with Other Transmission Systems

9.1 Joint Planning

The ITC Midwest system has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections. Joint planning is accomplished by participation in several regional planning groups.

9.2 Interchange Capability

Interconnections with other transmission systems are intended to facilitate the economic and reliability needs of generators and loads directly interconnected with the ITC Midwest system. In addition, these interconnections can also support the economic and reliability needs of generators and loads not directly interconnected with the ITC Midwest system. Interchange capability is the amount of power that can be transferred across transmission systems without exceeding transmission system facility limitations. Accordingly, the evaluation and planning of interchange capability is necessarily a joint effort by the concerned utilities. ITC Midwest participates in the transfer analysis performed by several regional planning groups.

10 Special Protection Systems (SPS)

It is ITC Midwest policy that new Special Protection Schemes (SPS) not be installed on the ITC Midwest system. ITC Midwest will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC Midwest system.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.

ITC MIDWEST

SUBTRANSMISSION PLANNING CRITERIA

BELOW 100 KV[1]

May, 2012

[1] This manual defines and explains the current planning criteria and will be reviewed and updated as required. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the subtransmission system unless some deviation is justified as a result of special, economic or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are <u>guidelines</u> to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

TABLE OF CONTENTS

1 Goal

This document describes the criteria to be used in assessing the reliability of the ITC Midwest subtransmission (below 100 kV[2]) system. This subtransmission planning criteria is intended to result in an ITC Midwest subtransmission system that economically and reliably allows our subtransmission system customers to serve load from generation of choice.

2 Thermal Loading and Voltage Planning Criteria

2.1 Design Considerations

The ITC Midwest system should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 1 – ITC Midwest Subtransmission Planning Criteria for allowable load loss by contingency type). Planning studies are to be carried out for projected annual peak system load conditions, but the planning criteria also holds for load levels less than annual peak.

The ITC Midwest system will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the subtransmission system. These needs may be communicated by reservations on the subtransmission system including network service or through other mechanisms.

Studies to determine subtransmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation.

MRO models are typically used to evaluate system performance. Details of model development can be found in the MRO Model Building Manual.

For those conditions and events that do not meet the performance requirements of Table 1 – ITC Midwest Subtransmission Planning Criteria, corrective plans involving capital projects will be developed. Operating guides will only be used as interim solutions, prior to completion of system upgrades.

2.2 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault

[2] For these criteria, this includes transformers with a low side voltage rating below 100 kV.

currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the planning criteria are violated.

- Relocation of ITC Midwest facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Repair, rebuild or replacement of facilities needed to provide acceptable reliability. This includes facilities which due to design no longer provides acceptable reliability and/or facilities in which normal maintenance is not effective to maintain reliability due to the overall condition of the facilities.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators must be considered when developing projects. The goal is to develop a robust subtransmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

2.3 Voltage and Facility Loading Criteria

Table 1 – ITC Midwest Subtransmission Planning Criteria

Description	NERC Category	Allowable Load Loss	Ratings Used [b]	Load Level [e]	Minimum Voltage [c,d,j]	Maximum Voltage [d,j]
System Normal [f]	A	none	normal	100%	95% [m]	105% [m]
Single Generator [g]	B1	none	emergency	100%	93% [n,k]	110% [k,p]
Single UG Cable [g]	B2	none [a]	emergency	100%	93% [n,k]	110% [k,p]
Single OH Line [g]	B2	none [a]	emergency	100%	93% [n,k]	110% [k,p]
Single Transformer [g]	B3	none [a]	emergency	100%	93% [n,k]	110% [k,p]
Bus Section [g]	C1	none [a,h]	emergency	100%	93% [n,k]	110% [k,p]
Double Circuit Tower [g,i]	C5	none [a,h]	emergency	100%	93% [n,k]	110% [k,p]
Circuit Breaker > 100 kV	C2	none [a,h]	emergency	100%	90% [o]	110% [k,p]
Double Contingencies > 100 kV [l]	C3	none [a,h]	emergency	100%	90% [o]	110% [k,p]

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.
b) The normal and emergency ratings are developed in accordance with PWR-601 ITC Midwest Equipment Thermal Load Ratings. The normal and emergency rating may be the same.
c) The Minimum Voltage requirement for 69 kV retail users without voltage regulation is 97.5 % normal, and 95.0% post-contingency. This includes Cargill (Eddyville), Griffin Wheel, Keokuk Steel, and Ogilvie Mills.
d) The voltage limits listed are steady state voltage limits. Voltage control devices (e.g., tap changers, switched shunts, and phase shifting transformers) should be set to control during the analysis.
e) The Load Level shown is the maximum load level (in percent of the system peak) to which this part of the criteria should be applied. It is also valid at any load level less than that shown.
f) Normal conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch. This would typically include municipal generators or a single generator dispatched off in the area of study.
g) Emergency conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch in addition to the transmission element outages. This would typically include at least a single generator dispatched off prior to applying the contingency under study.
h) There may be some load loss to a defined pocket of load as a direct consequence of the system topology.
i) Any two circuits of a multiple circuit towerline excludes transmission circuits where multiple circuit towers are used over a cumulative distance of 1 mile or less in length.
j) System Normal voltage limits represent pre-contingent system voltage limits (SOLs) under normal system conditions. Post-contingent system voltage limits (SOLs) are emergency voltage limits under abnormal or emergency system conditions.
k) Voltage must be restorable to the System Normal range after system adjustments. Action must be taken within 30 minutes of disturbance.
l) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. Action must be taken within 30 minutes of initial disturbance. The loss of two elements without time between for operator action is interpreted by ITC Midwest to be more severe than category C and is treated like an extreme contingency.
m) System Normal Minimum and Maximum Voltage limits for 34.5 kV are 102% and 108% respectively.
n) 99% for 34.5 kV buses
o) 96% for 34.5 kV buses. Voltage must be restorable to 93% for 69 kV and 99% for 34 kV after system adjustments. Action must be taken within 30 minutes of disturbance.
p) System studies should monitor at the System Normal Maximum Voltage.

Tests should be applied as appropriate to examine the system's susceptibility to voltage collapse. The system should be monitored for voltage deviations greater than 5%. The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) may be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

When contingencies result in buses being isolated from all sources of the same or higher voltage, it is not considered a violation of the planning criteria for voltages on the isolated buses to be outside the parameters of Table 1 - ITC Midwest Subtransmission Planning Criteria, provided that the voltages on the underlying system are within acceptable limits.

Projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 1 - ITC Midwest Subtransmission Planning Criteria for any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition. Where projects are proposed for additional dispatch scenarios, their use will be justified and documented.

3 Stability Criteria

Stability is the ability of a generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 1 – ITC Midwest Subtransmission Planning Criteria.

Generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on two transmission circuits on a multiple circuit tower with normal[b] clearing.
3. A single phase-to-ground fault at the most critical location[a] with delayed[c] clearing.
4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a three phase-to-ground fault at the most critical location[a] with normal[b] clearing.
5. A single phase-to-ground internal breaker fault with normal[b] clearing.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

Performance during and after the disturbance shall meet the requirements of the NERC TPL standard's Table 1 – Transmission System Standards – Normal and Emergency Conditions, and the requirements of the MRO System Performance Table of MRO Standard TPL-503-MRO-01.

A one-cycle[3] safety margin must be added to the actual or planned fault clearing time.

4 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within specified momentary and/or interrupting ratings for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

5 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

6 Voltage Deviation Standards

6.1 Capacitor Switching

The maximum percent change (step-change) in system voltage under normal system conditions shall be 3% when sizing capacitor banks.

6.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for a single generator tripping.

[3] The basis for the one-cycle safety margin is that it has historically been used by MAPP and is listed in the MAPP Members Reliability Criteria and Study Procedures Manual dated April 2009, and the MISO Transmission Planning Business Practices Manual dated 11-20-10.

6.3 Loss of an Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for a single transmission element tripping.

7 Coordination with Other Transmission Systems

The ITC Midwest system has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections. Joint planning is accomplished by participation in several regional planning groups.

8 Special Protection Systems (SPS)

It is ITC Midwest policy that new Special Protection Schemes (SPS) not be installed on the ITC Midwest system. ITC Midwest will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC Midwest system.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.

United States of America
Federal Energy Regulatory Commission

2010 FERC Form 715
Annual Transmission Planning and Evaluation Report

Part 4: Transmission Planning Reliability Criteria

ITC Great Plains subscribes to all current NERC and Southwest Power Pool ("SPP") Reliability Standards. The present SPP reliability criteria are available on the web at: http://www.spp.org/publications/Criteria02042010-with%20AppendicesCurrent.pdf

ITC Great Plains is a member of the Southwest Power Pool. The criteria used by the SPP to determine available transmission capacity can be found in Citeria 4 of the SPP Criteria, available on the web at the link listed above.

ITC *TRANSMISSION*
MICHIGAN ELECTRIC TRANSMISSION COMPANY

TRANSMISSION PLANNING CRITERIA

February, 2012

TABLE OF CONTENTS

1 Goal

This is the joint planning criteria for the ITC*Transmission* and Michigan Electric Transmission Company transmission systems. For simplicity in the remainder of this report, the joint systems will be referred to as the "Transmission System". This transmission planning criteria is intended to result in a Transmission System that economically and reliably allows our transmission system customers to serve their load from any generation of their choice.

2 NERC & ReliabilityFirst Reliability Criteria

ITC*Transmission* and Michigan Electric Transmission Company adhere to all current NERC and Reliability*First* Reliability Standards.

ITC*Transmission* and Michigan Electric Transmission Company also adhere to the legacy ECAR Document 1 approved October 20, 1967, revised November 6, 1980 and revised again July 27, 1998. ECAR Document 1 is entitled "Reliability Criteria for Evaluation and Simulated Testing of ECAR Bulk power supply system".

As members of Reliability*First*, ITC*Transmission* and Michigan Electric Transmission Company adhere to the legacy ECAR Document No. 1 and the statement contained therein that, "...The ECAR members recognize the impossibility of anticipating, and testing for, all possible contingencies that could occur on either the present or the future Bulk Electric Systems within ECAR. They believe, therefore, that the transmission reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies, that may or may not be readily visualized, rather than comprise a detailed listing of probable disturbances. Ultimately, the strength of the system as planned and operated must be sufficient to assure that any load loss has not been the result of or does not result in uncontrolled power interruptions. In view of this, the selection of reliability criteria is based not on whether specific contingencies for which the system is being tested are themselves highly probable but rather on whether they constitute an effective and practical means to stress the system and thus test its ability to avoid uncontrolled power interruptions."

In Table 1 of the NERC Planning Standards, four categories of conditions have been defined as follows (SLG is single line to ground and 3ϕ is three phase):

Table 1 – NERC Planning Standards

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Elements(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element	Single Line to Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:			
	1. Generator	Yes	No	No
	2. Transmission Circuit	Yes	No	No
	3. Transformer	Yes	No	No
	Loss of an Element without Fault	Yes	No	No
	Single Pole Block, Normal Clearing:			
	4. Single Pole (dc) Line	Yes	No	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing:			
	1. Bus Section	Yes	Planned/Controlled	No
	2. Breaker (failure or internal fault)	Yes	Planned/Controlled	No
	SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency	Yes	Planned/Controlled	No
	Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing:	Yes	Planned/Controlled	No
	5. Any two circuits of a multiple circuit tower line.	Yes	Planned/Controlled	No
	SLG Fault, with Delayed Clearing (stuck breaker or protection system failure):			
	6. Generator	Yes	Planned/Controlled	No
	7. Transformer	Yes	Planned/Controlled	No
	8. Transmission Circuit	Yes	Planned/Controlled	No
	9. Bus Section	Yes	Planned/Controlled	No

D Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences - May involve substantial loss of customer demand and generation in a widespread area or areas. - Portions of all of the interconnected systems may or may not achieve a new, stable operating point. - Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault)	
	6. Loss of tower line with three or more circuits	
	7. All transmission lines on a common right of way	
	8. Loss of a substation (one voltage level plus transformers)	
	9. Loss of a switching station (one voltage level plus transformers)	
	10. Loss of all generating units at a station	
	11. Loss of a large load or major load center	
	12. Failure of a fully redundant Special Protection Scheme (or Remedial Action Scheme) to operate when required.	
	13. Operation, partial operation, or miss-operation of a fully redundant Special Protection Scheme (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate.	
	14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

3 Introduction to Transmission System Planning Criteria

This planning criteria manual identifies the planning guidelines used to determine system needs and justify modifications to the transmission system. This manual defines and explains the current planning criteria and will be reviewed and updated as required.

The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the transmission system unless some deviation is justified as a result of special, economical or unusual considerations. Such instances should not necessarily be considered to conflict with this criterion or to justify revising the criteria, but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal reliability impacts. The planning criteria in this manual are guidelines to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

Planning for the transmission system is intended to provide a network capable of transmitting power between generating sources and loads. The Transmission System is utilized by various generation sources and loads throughout the Eastern Interconnection via Network Integration Transmission Service or various other forms of Transmission Service. The implementation of the projects and operating solutions identified by application of this planning criteria shall result in a Transmission System for which the probability of initiating cascading failures is very low. The system should also provide operating flexibility including, but not limited to, allowing maintenance outages. Loss of load may be tolerated for some system outages which occur during maintenance shutdowns, double and extreme contingencies.

In meeting the above objectives, the planning engineer must recognize present state-of-the-art equipment, understand construction practices, scheduling and the practical needs of operating the electrical system. It must be recognized that thermal overloading can shorten equipment life and lead to sudden failures and that abnormal voltages can also cause equipment failures and/or voltage sensitive equipment to be adversely affected. The planning engineer also needs to be cognizant of intangible considerations, such as the social and political implications of his work which include visual and ecological effects. In particular, one social implication that the planning engineer needs to consider is the social benefit of the loads being able to access the most economical generation available. Many of these elements cannot be guided by exact rules and the engineer's judgment must be factored into the proposed projects. In summary, the material gathered in this manual is intended to provide basic system planning guidelines. The planning engineer, however, must still apply ingenuity, experience and judgment in order to develop projects which lead to an economic and reliable power system and supports the access to economical generation. Where judgment is used, it should be recognized as such and documented so as to be part of the record for future planning.

The introduction of wind generation in Michigan has added a new dimension to the study and planning of the transmission system. One of the goals of any transmission system study should be to develop a transmission system capable of reliably delivering all types of generation on the system to the required loads at all appropriate load levels. Wind generation typically is at its highest output when system loading is not at its peak. The ITCT and METC planning criteria shall apply to system conditions at all load levels (as detailed in Table 2), including those when wind generation is at its peak.

4 Thermal Loading and Voltage Planning Criteria

4.1 Description

The transmission system is used to transmit power and energy from interconnected generation plants to interconnected loads. Some of the generation and load that utilize the Transmission System are not directly interconnected with the Transmission System but are part of the larger interconnected grid and utilize the Transmission System through its ties with neighboring systems.

4.2 Design Considerations

The Transmission System should be designed such that foreseeable normal and contingency conditions do not result in equipment damage or in exceeding acceptable loss of load (see Table 2 – Transmission System Planning Standards for allowable load loss by contingency type). Planning studies are to be completed for projected annual peak system load conditions, but the planning criteria is also applicable for loads less than the annual peak system load level. Planning studies to evaluate projected shutdown conditions (a single non-generator element shutdown plus a single element forced out) however, are to be evaluated at a lower load level (see Table 2 – Transmission System Planning Standards).

The Transmission System will be planned to be within its thermal capacity, to remain stable, to be within equipment short circuit capabilities, and to be within acceptable voltage limits while meeting projected needs of users of the transmission system. These needs may be communicated by reservations on the transmission system including network service requests or through other mechanisms.

When evaluating the system's expected performance, in the absence of specific customer identified generation resources (such as designated network resources), generation shall be dispatched on an assumed economic and probabilistic basis. In any case, including the system "normal" case, reasonable assumed forced and scheduled generator outages shall be considered. Studies to determine transmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant and adverse, but credible, dispatch scenarios for other nearby generation shall be considered.

4.3 Project Proposal Guidelines

Project proposals will be submitted if one or more of the following guidelines are met.

- Replacement of equipment which is unsafe to operate and/or presents a hazard. This includes projects required to replace interrupting devices that could be subjected to fault currents which exceed momentary or interrupting ratings, as well as projects required to replace equipment that periodic maintenance tests have shown to have incipient failure.

- Replacement of equipment that presents a costly maintenance burden. This includes projects required to replace equipment that periodic maintenance tests have shown increasing economic costs to maintain for reasons such as that equipment that is, or is becoming, obsolete.

- Interconnection of reasonably documented new customers or committed increases in load at existing customer stations. Related projects should be proposed if one or more of the guidelines under criteria Sections 4 through 7 are violated.

- Relocation of Transmission System facilities on public property as required by federal, state, county or local governmental units. Other requests for relocations are to be done only if the requestor has contracted to pay for the relocation or if economic justification exists.

- Repair, rebuild or replacement of equipment which has failed.

- Requirements to maintain spare equipment to a level sufficient to provide timely replacements for normal failure rates.

- Mitigation of instances with violations or projected violations of the planning criteria.

- Purchase of corridor, station and/or substation sites as needed for other projects. Approved property purchases can also be associated with reasonable expected future needs.

Reasonable future conditions such as load growth, changes in regional and interregional system flow patterns and future generators much be considered when developing projects. The goal is to develop a robust transmission system today which can be efficiently expanded to reliably and economically accommodate tomorrow's load and generation patterns.

4.4 Voltage and Facility Loading Criteria

4.4.1 Generally Applicable Criteria

Table 2 – Transmission System Planning Standards

ITC Transmission Description	NERC Category	Allowable Load Loss [j]	BES Level[n]	Ratings Used	Load Level[k] (% System Peak)	Minimum Voltage[h,l]	Maximum Voltage[h,l]
System Normal[e]	A	none	EHV, HV	normal	100%	97%	107%[b]
Single Generator (no Generators in proximity off in base case)[f]	B1	none	EHV, HV	normal	100%	97%	107%[b]
Single Generator (with other generators in proximity off in base case)[f]	B1	none	EHV, HV	emergency[c]	100%	92%	107%[b]
Single UG Cable[f]	B2	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Single OH Line[f]	B2	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Single Transformer[f]	B3	none[a]	EHV, HV	emergency[c]	100%	92%	107%[b]
Shunt Device[f,k]	B4	none[a]	EHV,HV	emergency[c]	100%	92%	107%[b]
Opening of a line section w/o a fault[f,o]	B5	none[a]	EHV,HV	emergency[c]	100%	92%	107%[b]
Bus Section[f]	C1	none[a]	EHV	emergency[c]	100%	92%	107%[b]
		100 MW[j]	HV	emergency[c]	100%	92%	107%[b]
Circuit Breaker[f]	C2	none[a]	EHV	emergency[c]	100%	92%	107%[b]
		300 MW[j]	HV	emergency[c]	100%	92%	107%[b]
Shutdown + Contingency[f,m,n]	B1, B2 or B3[i]	none[a]	EHV, HV	emergency[c]	85%	92%	107%[b]
Double Circuit Tower (DCT)[f]	C5	300 MW[j]	EHV, HV	emergency[c]	100%	92%	107%[b]
Double Contingencies[d,f,m,n]		500 MW[j]					
1. After First Contingency (Prior to System Re-Adjustment)	C3	none[a]	EHV, HV	emergency[c]	100%	Variable[g]	107%[b]
2. After First Contingency (After System Re-Adjustment)	C3	none[a]	EHV, HV	normal	100%	Variable[g]	107%[b]
3. After Second Contingency (Prior to System Re-Adjustment)	C3	500 MW	EHV, HV	emergency[c]	100%	Variable[g]	107%[b]
Extreme Contingencies[d,f]	D	no cascading	EHV, HV	emergency[c]	100%	no cascading	no cascading

a) There may be some consequential load loss in the event of the loss of a radial circuit, a transformer in direct series with a radial circuit or the loss of a load fed from a radial tap off of a network circuit provided the load lost was served directly by the outaged facility.

b) 110% is the generally applicable system (physical) limit and represents SOLs. For some specific locations a more stringent SOL limit may be applied. System studies should monitor and plan to 105% voltage due to contractual obligations with the Load Serving Entities. The contractual obligation does not define the SOL.

c) The emergency rating applied shall be of an appropriate duration considering both the piece of equipment limited and the contingency studied.

d) The NERC Planning Standards consider a single category B event followed by operator intervention followed by another category B event as a category C event. The loss of two elements without time between for operator action is interpreted by ITC to be more severe than category C and is treated like an extreme contingency.

e) Normal Conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch

f) Emergency conditions include an appropriate set of scenarios that consider appropriate generators not in the dispatch in addition to the single, double and multiple transmission element outages. This would typically include at least a single generator dispatched off prior to applying the contingency under study.

g) Minimum voltage during a double contingency or an extreme contingency is determined by the minimum voltage required at power plants to avoid widespread cascading outages. The minimum voltage requirements vary from plant to plant.
h) Some buses have individual voltage limits. These are reviewed on a case by case basis.
i) The voltage limits listed are steady state voltage limits. Voltage control devices (tap changers, switched shunts, phase shifting transformers...) should be set to control during the analysis.
j) In no circumstance should the contingency result in automatic tripping of a circuit or safety violations.
k) The Load Level shown is the maximum load level to which this part of the criteria should be applied. It is also valid at any load level less than that shown, for instance when studying the impact of wind generation dispatched at a load level less than system peak.
l) Allowable load loss is the sum of 1) any load lost directly following the event such as load fed radially off an outaged line and 2) any load shed to get within applicable limits.
m) Appropriate classification for multiple outages involving generators shall depend on the status of other generators in proximity in the starting case. For example, the shutdown of a generator and subsequent contingency shall be considered a "shutdown + contingency" should generation already be off in the proximity in the normal case. If generation is not off in the proximity in the base case, this shall be considered as a simple contingency.
n) Bulk Electric System (BES) level references include extra-high voltage (EHV) facilities defined as greater than 300 kV and high voltage (HV) facilities defined as the 300 kV and lower voltage systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of firm transmission service and non-consequential load loss.
o) Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
p) Opening one end of a line section without a fault on a normally networked transmission circuit such that the line is possibly serving load radially from a single source point.
q) A protection system maintenance shutdown or failure would constitute a viable contingency for Category B3 or C3 events.
r) All Nuclear Plant Interface Requirements (NPIRs) applicable to generator plants in the ITCT and METC footprints shall be monitored and upheld.

The reactive reserve in an area (comprised of "unused" reactive capability of generators or shunt capacitors) should be monitored in studies to identify possible voltage collapse scenarios. Low reactive reserves may be an indication of being near the "knee" of the PV curve.

Post-contingency voltages including those for the NERC category C events should be high enough to ensure that there would be no motor stalling on the distribution system. Other related tests should be applied as appropriate to examine the system's susceptibility to voltage collapse.

When studying the system, generators shall be dispatched on a basis that considers committed resources, assumed economics, and probabilities of forced and scheduled generator outages. It may be appropriate to consider conditions with multiple generator units unavailable in an area especially if the conditions being studied may be prevalent for an extended period of time. Further, as appropriate, the system should be analyzed to consider vulnerability to the extended outage or the retirement of any particular generating unit or plant.

For any reasonably expected generation dispatch pattern, or a dispatch that represent an average condition, notwithstanding documented application of judgment to the contrary, projects should be proposed if the loading on system elements (overhead conductors, underground cables and/or station equipment), minimum voltages, maximum voltages, or the amount of load loss are outside of the applicable contingency category parameters as set forth in of Table 2 - Transmission System Planning Standards.

Allowable load loss includes any load lost with the contingency plus manual load shedding. The planning engineer should evaluate any location for reductions in load that would reasonably be expected to reduce loading on the limiting circuit.

4.4.2 Shutdown Conditions

For load levels below the maximum planned for load level with shutdowns (see Table 2 - Transmission System Planning Standards), it is expected that the shutdown[1] of a single component would result in element loadings and system voltage with normal ranges as the system will be planned to be able to withstand a pre-existing shutdown of an element at or below a pre-determined load level. Further, it is expected that contingent loss of a component on top of the shutdown of a single component would result in element loadings and system voltages within emergency ranges.

Current TPL standards specify system performance studies be conducted to include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned outages are performed. This applies to both single and multiple contingency types (NERC category B, C and D). Planned outages in this case include only those scheduled from at least one year out from the time the planning analysis is finalized. Since maintenance outages are not typically planned that far in advance, ITC Planning Criteria goes beyond the compliance requirements and includes all combinations of NERC category B (single) contingencies with all other NERC category B (single) contingencies. The intent of this criteria is to ensure sufficient transmission system is planned to allow the required maintenance of Bulk Electric System (BES) equipment while being able to withstand the relatively higher probability of a NERC category B (single) event. Due to the relatively lower probability of a NERC category C (multiple) or NERC category D (extreme) contingency event, only scheduled planned outages are combined with category C and D contingencies in planning analysis.

When studying shutdown conditions, generators shall be dispatched on a basis that considers committed resources, assumed economics, and probabilities of forced and scheduled generator outages. It is assumed that during shutdowns, Transmission System Operations will minimize the risk exposure of such outages. However, it may be appropriate to consider conditions with multiple generator units unavailable related to generator maintenance outages or long generator start up times.

There must be a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, adjacent hazard and/or element replacement. Planning studies must therefore evaluate the system under shutdown conditions using the maximum planned for load level with shutdowns (see Table 2 - Transmission System Planning Standards). The maximum planned for load level with shutdowns should periodically be re-evaluated to ensure that the application of that criterion is consistent with the requirement of having a significant, continuous time during the year when a system element can be shutdown for inspection, maintenance, and adjacent hazard and/or element replacement.

[1] A shutdown is defined as a planned or forced outage of any single element on the transmission system.

4.4.3 Single Contingency Followed by Operator Action Followed by Another Single Contingency

The forced outage of a single generator, transmission circuit (or portion thereof) or transformer followed by operator interaction and then followed by another forced outage of a single generator, transmission circuit (or portion thereof) or transformer is considered to be a NERC Category C event. Under these conditions, no more than a pre-determined amount of Transmission System annual system peak load can be projected to be lost. This load loss considers intentional load shedding and the forced outage of load subsequent to the contingency. For load levels below the maximum planned for load level with shutdowns, if is expected that no load would be lost under these type of conditions as the system will be planned to be able to withstand the shutdown of an element plus the contingency loss of another element (see Table 2 – Transmission Planning Standards).

4.4.5 NERC Category D – Extreme Event

The Transmission System will be evaluated using a number of extreme contingencies that are judged by Planning to be critical. It is not expected that it will be possible to evaluate all possible facility outages that fall into NERC Category D. These events may involve substantial load and generation loss in a widespread area. These critical category D contingencies should not result in cascading outages beyond the Transmission System area and any immediately adjacent areas.

5 Stability Criteria

Stability is the ability of a turbine-generator or power system to reach an acceptable steady-state operating point following a disturbance. This requires that thermal loadings, load loss, and voltage following the disturbance are within the guidelines established in Table 2 – Transmission Planning Standards.

Pre-disturbance generation conditions should be selected to maximize generator real power, and minimize generator reactive power and voltage in the area where the disturbance is to be simulated. Power plants must maintain transient and voltage stability and have no adverse impact on the rest of the system, including other connected generators, when operating anywhere in the range from 0.90 lagging to 0.93 leading power. Where the generator does not have the capability to achieve the entire power factor range described above, it must be maintain stability throughout the actual feasible power factor range at the minimum generator voltage. Turbine-generator and system stability shall be maintained during and after the most severe of the contingencies listed below:

1. With the transmission system normal, a three-phase fault at the most critical location[a] with normal[b] clearing.
2. Simultaneous phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal[b] clearing.
3. A double phase-to-ground fault at the most critical location[a] with delayed[c] clearing.
4. With one element (transmission line, transformer, protective relay, or circuit breaker) initially out of service, a permanent three phase-to-ground fault at the most critical location[a].

5. A permanent phase-to-ground fault on a circuit breaker with normal clearing.

Generator minimum reactive limits should be determined based on the most severe post disturbance operating point that results from applying the above stability criteria. Generator minimum reactive limits are determined with and without the automatic voltage regulators in service.

a) Faults should be placed on generators, transmission circuits, transformers, and bus sections.
b) Normal clearing means that all protective equipment worked as intended and within design guidelines.
c) Delayed clearing means that a circuit breaker, relay or communication channel has malfunctioned or failed to operate within design guidelines. If the delayed clearing is due to a failure to operate, local and remote backup clearance is appraised.

6 Short Circuit Criteria

Short circuit currents are evaluated in accordance with industry standards as specified in the American National Standards report ANSI C37.5-1981 for older breakers rated on the total current (asymmetrical) basis and the American Standards Association report C37.010-1979 (Reaff 1988) for new breakers rated on a symmetrical current basis.

In general, fault currents must be within the specified momentary and/or interrupting ratings for the devices for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

7 Power Quality/Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement Documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

8 Voltage Deviation Standards

8.1 Capacitor Switching

The maximum percent change in system voltage under normal system conditions shall be 3% when sizing capacitor banks. Banks will also be sized to avoid harmonic resonance.

8.2 Loss of Generation

Over the normal generation availability range, with all transmission elements in service, the voltage change measured anywhere in the system shall be considered for tripping a single generator.

8.3 Loss of a Transmission Element

Over the normal generation availability range, the voltage change measured anywhere in the system shall be considered for the loss of a single transmission element.

9 Coordination with Other Transmission Systems

9.1 Joint Planning

The Transmission System has interconnections with neighboring systems. These systems include neighboring transmission systems as well as distribution systems. ITC*Transmission* and Michigan Electric Transmission Company also participate in the regional reliability coordination group called Reliability*First*, and have therefore agreed to certain principles for system planning and operating established therein.

The contractual commitments with the interconnected neighbors, as well as the properties of interconnected operations require coordinated joint planning with others of not only the interconnection facilities, but also consideration of the networks contiguous to those interconnections.

9.2 Interchange Capability Criteria

Interconnections with other transmission systems are intended to facilitate the economic and reliability needs of generators and loads directly interconnected with the Transmission System. In addition, these interconnections can also support the economic and reliability needs of generators and loads not directly interconnected with the Transmission System. Interchange capability is the amount of power that can be transferred across transmission systems without exceeding the transmission system's facility limitations. Accordingly, the evaluation and planning of interchange capability is necessarily a joint effort by the concerned utilities.

The desired import capability based on the Transmission System's annual peak load is to be provided for network conditions as defined in NERC document "Transfer Capability, A Reference Document" for normal and first contingency single element outages. Single elements include any single generator, transmission circuit (or portion thereof) or transformer.

10 Special Protection Systems (SPS)

It is ITC*Transmission* and METC policy that new Special Protection Schemes (SPS) not be installed on the ITC*Transmission* and METC systems. ITC*Transmission* and METC will not support the installation of an SPS on a neighboring system whose purpose is to mitigate potential issues on the ITC*Transmission* or METC systems.

For those SPS's that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or system improvements to remove the SPS are warranted.

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Entergy Arkansas, Inc., Mid South TransCo LLC, Transmission Company Arkansas, LLC and ITC Midsouth LLC for Approval of Transfer of Assets and Certificate of Convenience and Necessity, and Merger and, in connection therewith, Certain Other Related Transactions	))))))))	File No. EO-2013-0396

EXHIBIT TWV-3

MISO Committee Organizational Chart

MISO Entity Organization Chart