BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION OF ENTERGY ARKANSAS, INC., MID SOUTH TRANSCO LLC, ITC MIDSOUTH LLC, TRANSMISSION COMPANY ARKANSAS, LLC, AND ITC HOLDINGS CORP. TO ENTER TRANSACTIONS RESULTING IN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A NEW ARKANSAS UTILITY TO OWN EAI'S ELECTRIC TRANSMISSION FACILITIES	))))))))))))))	**DOCKET NO. 12-069-U**

SUR-SURREBUTTAL TESTIMONY OF

CAMERON M. BREADY

ON BEHALF OF

ITC HOLDINGS CORP. AND ITC MIDSOUTH LLC

JUNE 21, 2013

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cameron M. Bready. My business address is 27175 Energy Way, Novi, Michigan 48377.

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

A. I am Executive Vice President and Chief Financial Officer ("CFO") of ITC Holdings Corp. ("ITC"). As CFO, I am responsible for all of the financial operations of ITC. I oversee the accounting, financial reporting, investor relations, treasury, risk management, tax, internal audit and financial planning and analysis functions for ITC and its operating subsidiaries, including International Transmission Company d/b/a ITC*Transmission* ("ITCT"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITCMW") and ITC Great Plains, LLC ("ITC Great Plains"). In addition to my CFO responsibilities, I am also responsible for transmission development activities through ITC Grid Development, LLC. In this capacity, I manage efforts to identify new opportunities for ITC to participate in the development of, and investment in, transmission infrastructure in certain markets within the United States.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY TO THE COMMISSION?

A. Yes. I submitted Direct Testimony in this proceeding on September 28, 2012 and Rebuttal Testimony on May 17, 2013.

II. PURPOSE OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR SUR-SURREBUTTAL TESTIMONY?

A. I will respond to assertions in the Surrebuttal Testimonies of witnesses for the Arkansas Public Service Commission General Staff, the Arkansas Attorney General, Arkansas Electric Cooperative Corporation, Arkansas Cities, and Arkansas Electric Energy Consumers, Inc.

III. OVERVIEW

Q5. CAN YOU COMMENT GENERALLY ON THE SURREBUTTAL TESTIMONIES?

A. Yes. Some of the parties bring up the same issues and arguments in their surrebuttal testimonies that they raised in their direct testimonies. Generally these parties discount the many qualitative benefits that the applicants have shown will result from the transaction, disagree with how ITC and EAI calculated the rate impacts, argue that EAI could realize debt cost savings by refinancing debt itself, dispute the use of the return on equity approved for use by all MISO transmission owners, question ITC Holdings' capital structure, assert that shareholders are benefiting at the expense of customers, and contend that ITC will over-invest in transmission. I rebutted each of these assertions in my Rebuttal Testimony filed on May 17, 2013; accordingly, I will not individually address them further here, except to the extent the parties raise new arguments or issues in their surrebuttal testimonies, which I address below.

It is worth noting that, unfortunately, many parties miss the point of the discussion included in testimony regarding rate impacts. This is not a rate case. ITC and EAI are not attempting to demonstrate the precise rate following the Transaction. The analysis EAI witness Mr. Lewis and I have provided is only intended to show the order of magnitude for the rate impacts, without considering the larger benefits that the transaction would bring. Our calculations show that the rate effects will be modest in any case. This is especially so when the larger context is considered. That larger context includes the fact that the transmission cost component is only a small part of an average retail customer's bill and that the transactions will bring significant economic benefits to Arkansas' retail and wholesale customers, including reduced congestion, reduced line losses, and greater access to competitive generation. In addition to these benefits, there are significant benefits to be realized from improved reliability and system availability, storm hardening, and support of economic development.

Some parties also continue to claim that the FERC rate construct is somehow unreasonable. This is not the case.

First, ITC Arkansas will charge rates that a regulatory agency, FERC, determines are just and reasonable. FERC sets transmission rates recognizing the public policy objectives of investing in more beneficial transmission infrastructure in the country, so as to catch up with the backlog due to years of underinvestment, to replace aging infrastructure more quickly, and to modernize and make more regional a system that was built to respond to discrete local needs. While some parties think all regulatory agencies should set just and reasonable rates at the exact same level, using the same exact methods, there can be more than one just and reasonable rate, and more than one way to establish it. As the FERC Section 205 Order on the ITC Arkansas formula rate filing issued on June 20, 2013, demonstrates,[1] FERC regulation assures that ITC Arkansas will charge a just and reasonable rate.

In addition, with respect to the capital structure of ITC Holdings Corp. and its credit rating in comparison to Entergy Corporation, I want to correct a statement I made in my Rebuttal Testimony. In my Rebuttal Testimony, I misstated that ITC and Entergy Corporation have comparable ratings at Standard & Poor's ("S&P"). In fact, ITC Holdings Corp. is rated one notch higher than Entergy Corporation by S&P. Mr. Lewis confirms this in his Sur-surrebuttal Testimony.

IV. BENEFITS OF THE TRANSACTION

Q6. DO YOU AGREE WITH MR. PEACO (p. 5) THAT THE STANDARD USED IN THE COMMISSION'S ORDER NO. 6 IN THE SWEPCO-SW TRANSCO DOCKET DOES NOT LIMIT CONSIDERATION TO ONLY THOSE BENEFITS THAT CAN BE REASONABLY QUANTIFIED?

[1] *ITC Holdings Corp., et al.,* Order Conditionally Accepting Certain Proposed Tariff Revisions, Accepting and Suspending Certain Proposed Tariff Revisions, and Establishing Hearing and Settlement Judge Procedures, 143 FERC ¶ 61,257 (2013) ("Section 205 Order"). Among other things, the Section 205 Order set certain aspects of ITC Arkansas' (and other ITC Midsouth Operating Companies') and the Entergy Operating Companies' proposed MISO Attachment O formula rates, rate schedules, and proposed agreements filed pursuant to Section 205 of the Federal Power Act for hearing and settlement procedures. FERC summarily approved the key aspects of the ITC Arkansas FERC rate construct, including use of the MISO-wide 12.38% ROE, the proposed capital structure targeting 60% equity and 40% debt, and the use of a forward-looking Attachment O formula rate. In a companion order also issued on June 20, FERC approved the transaction pursuant to Section 203 of the Federal Power Act. *See ITC Holdings Corp. and Entergy Corporation*, 143 FERC ¶ 61,256 (2013).

A. Yes, I do. However, while Mr. Peaco concedes that qualitative benefits are to be considered, he also unreasonably demands that qualitative benefits be quantified in order to meet his "substantial evidence" test.

I do not agree with Mr. Peaco that there is very limited evidence of the benefits that customers will realize. My Direct and Rebuttal Testimony, as well as the testimony of numerous ITC and EAI witnesses, demonstrate the breadth of the benefits of this transaction, including the benefits of ITC's independent transmission company model; improved reliability through a properly planned transmission system; economies of scope and scale, increased financial flexibility for the Entergy Operating Companies ("EOCs");[2] and the benefit of independence brought by ITC.

Mr. Peaco also claims that very little assurance has been offered of the benefits that customers will receive. He fails to acknowledge that the proposed commitments offered by ITC and EAI are designed to provide such specific assurances.

Q7. MR. PEACO CONTINUES TO ASSERT (p. 43) THAT PRESERVATION OF ADIT IS NOT A BENEFIT OF THE TRANSACTION. HOW DO YOU RESPOND?

A. Mr. Peaco is making an incorrect comparison. Mr. Peaco says the comparison should be between this transaction and status quo, *i.e.*, no transfer of ownership of the transmission system. However, Entergy and ITC have entered into an agreement through which the

[2] My rebuttal testimony uses the term "ITC Midsouth Operating Companies" to refer collectively to ITC Arkansas LLC, ITC Louisiana LLC, ITC Mississippi LLC and ITC Texas LLC, the new ITC subsidiaries which will own and operate the former transmission assets of the Entergy Operating Companies. My rebuttal testimony uses the term "Entergy Operating Companies" or "EOCs" to refer collectively to Entergy Arkansas, Inc. ("EAI"), Energy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc.

EAI transmission assets will be transferred to ITC. By entering into such agreement, Entergy has made a decision to exit the transmission business. Consequently, proceeding from the assumption that the transmission assets are to be separated from EAI, the logical question is whether the transaction structure that has been chosen, when compared to other possible transaction structures, offers benefits with respect to ADIT. Mr. Peaco does not dispute that a benefit of the RMT transaction structure is that ADIT is not reset, and customers will not experience any rate effects related to ADIT as a result of this transaction.

V. <u>RATE IMPACTS</u>

Q8. WILL YOU ADDRESS MR. PEACO'S REVENUE REQUIREMENT PROJECTIONS?

A. I disagree with certain assumptions Mr. Peaco has included in his revenue requirements, which causes me to believe that his projections are not accurate. The projected revenue requirement contained in Mr. Peaco's surrebuttal testimony includes forward test year impacts on a cumulative basis. As I discussed in my Rebuttal Testimony, use of the forward test year has only a timing effect on revenue requirements. The total amount of revenue collected over the life of an asset is not affected. The transmission revenue requirement will be collected sooner than it would be under an historical test year, but the actual total revenue requirement collected will not change. For these reasons, the use of the forward test year should not be included when measuring the rate effects of the transaction.

Q9. MR. PEACO (pp. 10-11) AND MR. DANIEL (p. 10) CLAIM THAT THE RATE IMPACT ANALYSIS IS UNDERSTATED BECAUSE ITC HAS NOT ATTEMPTED TO ESTIMATE THE MAGNITUDE OF FUTURE EXPENDITURES. DO YOU AGREE?

A. No. As I said in my Rebuttal Testimony, until ITC has an opportunity to own, operate and plan the transmission system, it is not possible to predict the precise levels of capital investment above the EAI forecast that will be required.

With respect to the potential impact on rates stemming from increased capital spending, EAI witness Jay Lewis did in fact address this in his direct testimony. Mr. Lewis provided an illustrative sensitivity calculation reflecting a 10 percent variance of capital spending by ITC beyond EAI's currently planned spending in EAI Exhibit JAL-5. Mr. Lewis recognized in his testimony that any analysis of increased capital expenditures can only be illustrative "because ITC will only be able to make a full and proper assessment of the appropriate levels of spending once it has some experience owning and operating these transmission assets." (Lewis Direct Testimony, p. 39, lines 2-4). Importantly, Mr. Lewis' analysis confirms that even with a 10% increase in capital investment over what was assumed for EAI, the effect on customer bills would be extremely modest (an additional $0.04 on the typical monthly residential bill). (EAI Exhibit JAL-5, p. 2 of 3.)

Any incremental investment by ITC above the EAI forecast would be made because the transmission system requires it. The intervenors' and staff witnesses' testimonies cast increased transmission investment as a negative, when having ITC in the position to make investment that is needed is a benefit of the transaction. As I stated in my Rebuttal

Testimony, our capital investment program provides benefits to customers from improved reliability and greater access to markets, which will lower the cost of delivered energy. Customers also will benefit from ITC's ability to make needed investments at a lower cost of debt.

Finally, since all of ITC's transmission investments are approved through the MISO planning process, for those ITC operating companies that are currently members of MISO, as ITC Arkansas will be, customers have assurances that all investment made by ITC in the transmission system is approved by an independent party and deemed necessary to improve reliability and/or provide economic benefits to customers in excess of their cost.

Q10. MESSRS. PEACO (p. 9), DANIEL (p. 10) AND SOLOMON (p. 15) RAISE THE POTENTIAL FOR ADDITIONAL COSTS DUE TO THE FACT THAT ITC COULD REQUEST INCENTIVE ROEs IN THE FUTURE. WOULD YOU PLEASE RESPOND?

A. This is pure speculation on their part. As I explained in my Rebuttal Testimony, ITC has not asked for an incentive ROE for ITC Arkansas. As ITC witness Thomas Wrenbeck testifies in his sur-surrebuttal Testimony, any future request for an incentive ROE would require a separate approval from FERC under Section 205 of the Federal Power Act through a public proceeding in which the Commission, customers and all interested stakeholders would have a full opportunity to participate.

I would also note that any subsequent change in ROE would be reflected in the rate mitigation plan discussed below, for the period that such plan remains in effect.

Q11. DO YOU AGREE WITH MR. MARCUS (pp. 4-5) THAT THE DEBT COST SAVINGS ANALYSIS SHOULD USE ONLY A 50 BASIS POINT DIFFERENTIAL?

A. No. Mr. Marcus' argument regarding the use of the 50 basis point differential stems from his refusal to recognize that the appropriate comparison for purposes of calculating debt cost savings is between the embedded cost of debt that is being replaced at EAI with the new cost of debt that ITC Arkansas can obtain. This is the proper comparison, not, as Mr. Marcus asserts, a comparison between the debt that EAI might obtain today and the financing that ITC Arkansas expects to put in place. Thus there is no valid basis for Mr. Marcus' suggestion that the debt cost differential is only 50 basis points.

Q12. DOES MR. MARCUS OR MR. FALKENBERG ACKNOWLEDGE THAT THE USE OF A FORWARD TEST YEAR COUPLED WITH A TRUE UP ASSURES THAT ONLY THE ACTUAL REVENUE REQUIREMENT IS RECOVERED?

A. No. Neither Mr. Marcus nor Mr. Falkenberg recognizes that the forward test year under the ITC Arkansas formula rate is combined with a true up that adjusts rates so that only the actual revenue requirement is recovered. No more is paid; the forward test year simply changes the timing of recovery of the annual revenue requirement.

Mr. Falkenberg claims that "[c]ustomers are paying the total revenue requirement of the utility, and the amount charged will be higher because the recovery of costs is more rapid with a forward test year." This statement acknowledges that all ITC Arkansas will do is recover its costs. While that recovery may be more rapid with the forward test year, the same amount of costs will be recovered, not some higher amount. The true-up assures this. In addition, in periods when expenses are decreasing or rate base is declining, the converse of this is true. Customers will realize the impact of this more rapidly than they otherwise would absent the use of a forward test year.

Mr. Falkenberg also fails to recognize the need for the use of the forward test year. As I explained in my Rebuttal Testimony, the forward test year is important to more closely match cost causation and cost recovery. The use of a forward test year improves cash flow generation, which is important since the capital needs of ITC Arkansas are expected to significantly outpace the cash flow generated by the transmission business. FERC has recognized this need, and has approved ITC Arkansas' use of the forward test year.[3]

As part of his argument regarding the forward test year, Mr. Marcus claims (p. 3) that when a future test year is used, rates in a particular year "will always be higher. . . as long as the combination of growth in rate base plus real growth in operating expenses due to added plant plus inflation is growing faster than 12 coincident peak (12CP) demand." Mr. Marcus' assertion that the forward test year causes revenue requirements to grow is incorrect. The forward test year does not affect the amount of the revenue requirement that ultimately is recovered, only the timing of its recovery.

Finally, as I discussed above, Mr. Peaco relied on the inclusion of the revenue effects of the forward test year in his revenue requirement analysis, which, as I discussed in my Rebuttal Testimony, should not be considered.

[3] *See* Section 205 Order, P 89: "The use of a forward-looking formula rate, along with the true-up mechanism, ensures that customers will ultimately only pay the cost of service they would have paid on a lagging basis. Forward-looking formula rates, if properly designed and supported, as is the case here, are acceptable to avoid lag in cost recovery" (footnotes omitted).

Q13. MR. MARCUS STATES (p. 6) THAT THE FACT THAT ITC RECOVERS 100% OF SHORT-TERM AND STOCK-BASED INCENTIVE COMPENSATION AND D&O INSURANCE HAS NOT BEEN ADDRESSED. HOW DO YOU RESPOND?

A. This appears to be an area where the components of just and reasonable rates under FERC regulation differ from the rate components under state rate regulation. However, ITC does not recover through rates 100% of short-term and stock-based incentive compensation or D&O insurance. Incentive compensation, like all components of compensation for ITC employees, follows labor charges. Incentive compensation associated with internal labor spent on activities that are recoverable in rates is included in customer rates for the relevant operating company. But incentive compensation associated with internal labor spent on activities that are not recoverable in rates (*e.g.*, development activities, transaction work, etc.) is not included in any operating company's customer rates.

D&O insurance is a corporate expense that cannot be charged directly to a particular operating company or business unit. This expense is allocated to the various ITC business units based on ITC's application of a modified Massachusetts Formula.[4] Each operating company's allocated share of such corporate expenses is included in A&G expense that is recovered in rates.

Q14. MR. PAINTER (p. 10) STATES THAT THE RATE EFFECTS HAVE NOT BEEN SEGREGATED BETWEEN WHOLESALE AND RETAIL. PLEASE RESPOND.

[4] For an explanation of this cost allocation methodology, please see the Stibor Testimony filed at FERC in Docket Nos. EC12-145-000, *et al*., and available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13071046.

A. Detailed information on potential wholesale rate effects of the transaction has been presented in the FERC filing seeking approval of this transaction, consistent with FERC's jurisdiction over wholesale transmission rates. For this reason, the rate effects discussion presented in this proceeding has been tailored to address the impacts on retail ratepayers. ITC and Entergy have modeled the estimated effects on wholesale transmission rates resulting from the transaction. This modeling focused on the change in capital structure and the benefits of ITC's improved credit quality, which yields lower debt financing costs. Collectively, I refer to these as the "changes in weighted average cost of capital." ITC and Entergy compared the expected weighted average cost of capital for the Arkansas pricing zone in 2014 under EAI ownership in MISO with the anticipated weighted average cost of capital for the Arkansas pricing zone in 2014 under ITC ownership.[5] This difference in the weighted average cost of capital was then applied to the projected annual average rate base balance for EAI to derive the change in total transmission revenue requirement. Lastly, the change in total transmission revenue requirement was divided by the projected 12 coincident peak load forecast for the Arkansas pricing zone in 2014, as provided to me by Entergy, to determine the expected wholesale rate impact for the Arkansas pricing zone from the Transaction.

As shown on my Exhibit CMB-10, wholesale transmission rates are estimated to increase approximately \$0.20/KWM in the Arkansas pricing zone in 2014 as the result of the transaction. This illustrative analysis does not reflect the rate mitigation proposal discussed below.

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[5] Although the Transaction is expected to close in 2013, the analysis was conducted for 2014 to avoid the complexity of modeling partial years.

VI. CAPITAL STRUCTURE

Q15. WOULD YOU LIKE TO COMMENT ON THE MOODY'S REPORT ATTACHED TO MR. MARCUS' SURREBUTTAL TESTIMONY AS EXHIBIT WBM-SR-1?

A. Mr. Marcus uses the Moody's report[6] to support his view that ITC would be "vulnerable" to changes in FERC ROE levels. As I testified in response to Mr. Marcus' original assertions regarding ITC's dependence on the continuation of existing FERC policies, the financial position of every utility is a function of its rate construct and every utility is subject to the risk that its regulator will change its rate construct. The Moody's report confirms that FERC historically has been supportive of transmission investment, and opines that "the need to increase and bolster the nation's transmission infrastructure remains strong, such that the FERC would likely refrain from making any drastic policy change that would disincentivize further investment."[7] Moreover, the Moody's report analyzes possible reductions in ROE to conclude that the change to cash flow and the ratio of cash flow pre-working capital to adjusted debt would not be considered meaningful enough to move ITC's overall ratings.[8]

Q16. HOW DO YOU RESPOND TO MR. MARCUS' CLAIMS (p. 12) REGARDING ITC'S ISSUANCE OF NEW EQUITY AS PART OF THIS TRANSACTION?

A. It appears that Mr. Marcus has now changed his position on how credit quality should be evaluated. In his initial testimony, Mr. Marcus highlighted ITC's existing debt to book

[6] Moody's Investors Service, "Special Comment: U.S. FERC Regulatory Environment," May 9, 2013 ("Moody's report").
[7] Moody's report, p. 3.
[8] Moody's report, p. 10.

capitalization ratio (approximately 70%) to support his argument that ITC is over levered. Upon learning that, due to the transaction, ITC's debt to book capitalization ratio post-closing actually will be lower than Entergy Corporation's consolidated position, Mr. Marcus retreats from his emphasis on debt to book capitalization and argues instead that the more important metric to consider in evaluating credit quality is interest coverage. Regardless of Mr. Marcus' views on how credit quality is to be measured, the key point is that the ratings agencies (and investors) take into account a variety of factors when evaluating credit quality, including regulatory framework and ability to recover costs and earn returns, in addition to credit metrics. When the credit quality of ITC Holdings is compared to that of Entergy Corporation, either pre- or post-closing, there is no question that ITC has higher credit quality, as evidenced by our ratings and debt pricing. It is also worth noting that the positive effect of the transaction is reflected in the ratings upgrade for ITC issued by Standard & Poor's after the transaction was announced in December 2011.

Q17. DOES MR. SOLOMON OFFER ANY REBUTTAL OF THE TESTIMONY REGARDING FERC'S USE OF THE CAPITAL STRUCTURE OF THE OPERATING COMPANIES, NOT THE PARENT HOLDING COMPANY, FOR PURPOSES OF RATEMAKING?

A. No. He merely restates his prior argument. The fact remains that the key capital structure that FERC considers for ratemaking purposes is the actual capital structure of the operating companies which, as explained, targets 60% equity / 40% debt.

The FERC Section 205 Order approves ITC Arkansas' use of its actual capital structure targeting 60% equity / 40% debt.[9] FERC also rejected "double leverage" arguments similar to those made here:

> Protestors have not presented evidence or provided any basis to depart from our policy that the regulated utility's actual capital structure is used in establishing the overall rate of return so long as it meets the three-part test outlined above. Further, the Commission has addressed similar double leveraging arguments and found that the rate of return should not depend on who owns the facility, nor on how that owner, whether a holding company or individual stockholders, financed its investment. Also, we find that the Louisiana Commission's arguments that the highly leveraged nature of ITC Holdings may negate the debt cost savings are unsubstantiated. We find that the proposed capital structure is just and reasonable, as explained above, and has been shown to contribute to achieving and maintaining credit ratings and accessing capital markets.

Section 205 Order, P 79 (footnotes omitted).

Q18. MR. FALKENBERG (p. 32) ASSERTS THAT YOUR REBUTTAL TESTIMONY STATES THAT ITC IS A MORE RISKY ENTERPRISE THAN EAI. DO YOU AGREE WITH THIS CHARACTERIZATION OF YOUR REBUTTAL TESTIMONY?

A. No. My testimony made no comparison with EAI with respect to the extent of business risk. The portion of my Rebuttal Testimony quoted by Mr. Falkenberg explained why the 60% equity / 40% debt capital structure supports ITC's high credit quality by supporting cash flow, liquidity and access to capital markets.

Q19. MR. SOLOMON CONTENDS (p. 9-10) THAT ITC CANNOT DEMONSTRATE THAT EACH OPERATING COMPANY'S SHARE OF TAXES IN ITC'S CONSOLIDATED TAX RETURN IS CONSISTENT WITH THE INCOME

[9] Section 205 Order, P 78.

TAXES CHARGED TO CUSTOMERS THROUGH FORMULA RATES. PLEASE RESPOND.

A. Mr. Solomon repeats his assertions regarding "phantom taxes," which I have already addressed in my Rebuttal Testimony. For the further information of the Commission, Mr. Solomon's assertion appears to be premised on his belief that if ITC's operating companies use their own capital structures instead of that of the parent ITC Holdings, "phantom taxes" are created. As FERC found in the Section 205 Order,[10] this argument has no merit. As I already explained, consistent with FERC precedent, ITC Arkansas and the other ITC Midsouth Operating Companies appropriately will use their own actual capital structures targeting 60% equity and 40% debt.[11]

As I also already explained in my Rebuttal Testimony, each ITC Midsouth Operating Company will be responsible for its share of income taxes as part of the ITC Holdings Corp. consolidated tax return.[12] The income taxes incurred at each Operating Company will include the income taxes on the allowed equity return generated by the Operating Company. The equity returns generated at each Operating Company are real income with real tax effects. Mr. Solomon's argument that the taxes associated with these equity returns are somehow "phantom" is not accurate. The recovery of the taxes on this income by the ITC Midsouth Operating Companies is entirely consistent with FERC policy, as FERC concluded in the Section 205 Order.[13]

[10] Section 205 Order, P 80.
[11] Rebuttal Testimony, pp. 30-32.
[12] Rebuttal Testimony, p. 34.
[13] Section 205 Order, P 80: "Under our income tax policy, public utilities are entitled to receive an income tax allowance when they pass-through profits to their parent and the parent incurs an actual or potential income tax liability on the distributive income received. It is therefore appropriate to provide the New ITC Operating

Finally, Mr. Solomon is correct that ITC's tax obligation on a consolidated basis is less than the tax obligations of the Operating Companies as a result of tax deductions at ITC Holdings. The existence of deductions at the holding company, while they affect ITC Holding's overall tax liability, does not make the taxes on the equity returns at each Operating Company any less real. Just as the interest expense associated with holding company debt and other non-recoverable expenses at ITC Holdings are not included in Operating Company rates, neither should any deductions associated with these expenses be included in rates. Therefore, Mr. Solomon's contention that the holding company tax deductions should somehow be passed on to customers is unsupported.

VII. <u>TRANSACTION STRUCTURE</u>

Q20. MR. FALKENBERG CONTENDS (pp. 3, 5) THAT BECAUSE OF THE SHARE OWNERSHIP OF ENTERGY SHAREHOLDERS, ENTERGY AND ITC WILL HAVE AN AFFILIATE RELATIONSHIP. IS THIS CORRECT?

A. No, that is patently false. My Rebuttal Testimony explained that it is the Entergy Corporation shareholders, not Entergy Corporation or any of the EOCs, who will hold ITC stock. The share ownership by Entergy shareholders raises no issue regarding ITC's independence. Indeed, FERC has expressly confirmed ITC's independence in the Section 205 Order.[14]

Companies with an income tax allowance because ITC Holdings will incur an income tax liability on the distributive income received from its subsidiaries."

[14] The Section 205 Order approved the proposed Appendix I Agreement under which the ITC Midsouth Operating Companies will be independent transmission company members of MISO. Section 205 Order, P 164. Full independence is a prerequisite for the use of an Appendix I Agreement, and as the FERC states in the Section 205 Order, "as the Commission has previously determined, ITC Holdings' ownership structure will prevent market participants from being able to influence or control one of its operating companies and thus undermine its independence." Section 205 Order, P 165 (footnote omitted).

Counsel has advised me that under applicable Arkansas[15] and Federal law[16] and APSC[17] and FERC regulations,[18] EAI and ITC Arkansas will not have an affiliate relationship. EAI will simply be a customer of ITC Arkansas.

VIII. SECURITIZATION

Q21. MR. FALKENBERG (p. 25) ASSERTS THAT ITC HAS NOT INDICATED A WILLINGNESS TO USE SECURITIZATION IN ARKANSAS FOR STORM DAMAGE COSTS. PLEASE EXPLAIN ITC'S VIEWS ON THE USE OF SECURITIZATION BONDS.

A. First of all, it is important to note the securitization is not a panacea for "funding" storm restoration activities. In the event of major storm damage, utilities need to have the appropriate liquidity and efficient access to capital to restore service quickly. Securitizations are time consuming to put into place and cannot be relied upon to provide immediate funds to restore service. Securitization bonds are primarily tools to address the long term financing of storm restoration activities.

ITC generally believes that utilities should be positioned to address the financial requirements associated with storm damage to transmission without securitizations. Damage to the transmission system in past storms has accounted for approximately 10% to 15% of total storm damages incurred in the Entergy Operating Companies' service

[15] *See* Ark. Code Ann. §§ 23-1-101(1)(A)-(D), 23-3-302(2) and 23-18-103(a)(1).
[16] Public Utility Holding Company Act of 2005, 42 U.S.C. § 16451(1) and (4).
[17] APSC Affiliate Transaction Rules, Rule III A.
[18] 18 C.F.R. § 366.1. Under FERC regulations, an affiliate of a company is "any company, 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company."[18] A company is defined as "a corporation, partnership, association, joint stock company, business trust, or any organized group of persons, whether incorporated or not." Since Entergy will not own any shares of ITC Holdings, Entergy will not be an affiliate of ITC.

territories and the absolute dollar impact of these storms on the Entergy transmission system has been very manageable. However, we would be willing to consider utilization of securitization bonds in the event of a catastrophic event which leads to extreme transmission system damage, and results in exceptional storm restoration costs.

IX. PROPOSED COMMITMENTS

Q22. YOUR REBUTTAL TESTIMONY CONTAINED PROPOSALS TO ADDRESS CONCERNS THAT HAVE BEEN RAISED REGARDING THE TRANSACTION. HAVE ITC AND EAI AGREED TO A REVISION TO THE PROPOSALS PRESENTED IN YOUR REBUTTAL TESTIMONY?

A. Yes. After careful consideration of all of the input that we have received from parties to this proceeding and those in the other Entergy retail jurisdictions, we have revised the proposed commitments made in my Rebuttal Testimony. A summary of the revised commitments of ITC Arkansas and proposed mutual commitments of EAI and ITC Arkansas are presented below. These include augmented rate mitigation proposals.

Q23. CAN YOU PROVIDE AN OVERVIEW OF THE RATE MITIGATION PROPOSALS?

A. We have made a fundamental change in the rate mitigation proposal to ensure alignment of the realization of all of the benefits that this transaction offers to customers and the rate impacts resulting from it. Further, the new proposals respond to the concerns that have been expressed regarding the need to demonstrate tangible and quantifiable benefits of the transaction. Under the proposal as set forth below, ITC Arkansas and EAI will bear rate mitigation risk until the benefits of ITC ownership are calculated and demonstrated. Specifically, ITC Arkansas and EAI are proposing a rate mitigation plan for the first five years following the close of the transaction that is calculated based on 100% of the estimated annual retail revenue requirement effects from the change in weighted average cost of capital ("WACC") resulting from ITC's ownership of the transmission system. As described more fully in the proposal below, annual WACC effects on retail revenue requirements (herein referred to as "WACC Effects") are determined based on the difference between ITC Arkansas' projected annual WACC and EAI's retail WACC as of December 5, 2011.

At the end of the first five years following the close of the transaction, in order for rate mitigation to end, ITC Arkansas must demonstrate that the annual benefits of ITC's ownership of the transmission system exceed the actual annual WACC Effects of ITC Arkansas' ownership of the assets. If such a demonstration cannot be made, then rate mitigation will continue until such time as it can. The determination that benefits exceed the annual WACC Effects would be made by an independent third party evaluator.

Q24. HAS THE LEVEL OF THE PROPOSED RATE MITIGATION INCREASED?

A. Yes, it has. For the first five years, ITC and EAI will provide $110.7 million in rate mitigation funds. At this time, we anticipate that this amount will be provided to customers via a combination of reductions in wholesale revenue requirements and retail customer bill credits. In addition, for the first three years, additional rate mitigation of $6.9 million will be provided through retail customer bill credits to offset the timing effects of moving from the historical test year used by EAI to the forward looking test year to be used by ITC Arkansas.

Q25. WHAT HAPPENS TO THE RATE MITIGATION AFTER FIVE YEARS?

A. After the initial five years, the rate mitigation will cease if the demonstrated annual benefits of ITC's ownership of the transmission system exceed the actual annual WACC Effects, based on the benefit test set forth in Appendix B of the proposal in my Exhibit CMB-11.

The first benefit test will be conducted in the fifth year following the close of the transaction. If less than 100% of the actual annual WACC Effects have been offset, then the rate mitigation will continue. The amount of the rate mitigation after year 5 will be based on the projected annual WACC Effects, net of the percentage of actual annual WACC Effects that were offset by demonstrated benefits in the previous test. In addition, if at the end of the fifth year following the close of the transaction the benefits of ITC ownership do not offset 100% of the actual annual WACC Effects, then ITC Arkansas and EAI will true-up rate mitigation for the difference between actual WACC Effects for the first five years, less benefits calculated per the benefit test, and the rate mitigation provided.

Q26. HOW LONG WILL RATE MITIGATION CONTINUE?

A. Rate mitigation will continue until such time as the demonstrated annual benefits as determined through application of the benefit test exceed the actual annual WACC Effects. EAI's responsibility for sharing in rate mitigation will cease at the end of 20 years after closing. After that time, ITC will be responsible for all rate mitigation until the annual benefits exceed the annual WACC Effects.

Q27. WHEN WILL ADDITIONAL BENEFIT TESTS BE CONDUCTED?

A. After the first test at the end of the fifth year following the close of the transaction, additional benefit tests can be conducted for any annual period at ITC Arkansas' discretion. If the results of any benefit test show that the amount of actual annual WACC Effects minus demonstrated annual benefits exceeds the rate mitigation that has been provided since the last calculation, then rate mitigation will continue and another true-up calculation will be conducted.

Q28. WHAT ARE THE COMPONENTS OF THE BENEFIT TEST, AND HOW ARE THEY TO BE WEIGHTED?

A. Three general categories of benefits will be evaluated: 1) improved system performance; 2) improved system economics; and 3) tangible economic benefits that are not readily quantifiable.

Improved system performance will be measured by reductions in outage frequency and duration, among other things. Such "reliability benefits" may account for no more than 45% of the amount needed to offset the annual WACC Effects. Improved system economics will be shown through congestion and fuel savings, reduction in operating reserves, reduction in reserve margins, and reduction in line losses, among other measures.

The category of benefits that are not easy to quantify will be presumed to provide 10% of the annual WACC Effects offset. These are benefits that are sure to exist in a variety of categories, including storm hardening, economic development, job creation, and increased capacity to serve load, among other things.

Q29. HOW WILL THE BENEFIT TEST BE CONDUCTED AND REVIEWED?

A. A third party evaluator selected by ITC will perform the benefit tests as necessary. The results of the benefits test will be submitted to the Commission.

Q30. PLEASE PROVIDE THE PROPOSED COMMITMENTS AND SUPPORTING MATERIALS.

A. The ITC Arkansas and EAI proposed commitments, along with Appendix A (Supplemental Proposed Commitments for Arkansas (including rate mitigation)) and Appendix B (Calculation of ITC Ownership Benefits) are provided in my Exhibit CMB-11.

Q31. WILL ITC AND ENTERGY MAKE SIMILAR COMMITMENTS IN THE OTHER JURISDICTIONS THAT ARE REVIEWING THE TRANSACTION?

A. Yes.

Q32. MR. MARCUS (p. 8) AND MR. LATHAM (pp. 59-61) CITE A FERC AUDIT OF ITC MIDWEST AS EVIDENCE THAT ITC MAY NOT LIVE UP TO ITS COMMITMENTS MADE HERE. WOULD YOU LIKE TO RESPOND?

A. ITC takes seriously our obligation to comply with regulatory requirements and to honor the commitments that we undertake voluntarily. With respect to the audit referenced by Mr. Marcus and Mr. Latham, FERC staff and ITC disagreed about a highly technical issue dealing with the proper accounting for the tax effects of amortized goodwill. We continue to believe that our accounting was appropriate. However, in compliance with

FERC's decision, we have filed, and FERC has accepted, a refund report. Importantly, the acquisition premium associated with the purchase of transmission assets by ITC Midwest has at all times been excluded from ITC Midwest's rate base. The transaction with Entergy is not a taxable transaction, and any goodwill associated with it will not be tax deductible, and therefore no such accounting issues will arise here.

The relevance of the ITC Midwest audit here is not that ITC's commitments are insufficient, but that its actions in this matter demonstrate that FERC's regulation is not merely perfunctory, as Mr. Falkenberg would have the Commission believe.

Q33. DOES THIS CONCLUDE YOUR SUR-SURREBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I, Randall L. Bynum, do hereby certify that a copy of the foregoing has been served upon all parties of record by forwarding the same by electronic mail and/or first class mail, postage prepaid, this 21st day of June 2013.

/s/Randall L. Bynum
Randall L. Bynum

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION OF ENTERGY ARKANSAS, INC., MID SOUTH TRANSCO LLC, ITC MIDSOUTH LLC, TRANSMISSION COMPANY ARKANSAS, LLC, AND ITC HOLDINGS CORP. TO ENTER TRANSACTIONS RESULTING IN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A NEW ARKANSAS UTILITY TO OWN EAI'S ELECTRIC TRANSMISSION FACILITIES	**DOCKET NO. 12-069-U**

ITC EXHIBIT CMB-10

WHOLESALE RATE EFFECTS

Exhibit CMB-10 - Illustrative 2014 Rate Effect Schedule for Wholesale Customers Charged the OATT Rate in Arkansas Pricing Zone

		ITC Arkansas
1	**ITC Ownership**	
2	After-Tax Return on Equity	12.38%
3	Equity Component of Capital Structure	60.0%
4	Pre-Tax Cost of Debt[a]	3.5%
5	Debt Component of Capital Structure	40.0%
6	Federal Tax Rate	35.0%
7	State Tax Rate[b]	6.5%
8	Pre-Tax Weighted Average Cost of Capital (WACC)	13.6%
9		
10	**ETR Ownership**[b]	
11	After-Tax Return on Equity	12.38%
12	Equity Component of Capital Structure	42.5%
13	Interest Rate on Non-Deductible Preferreds	6.0%
14	Weighting of Non-Deductible Preferreds Component of Capital Structure	3.0%
15	Pre-Tax Cost of Debt	5.3%
16	Debt Component of Capital Structure	54.5%
17	Federal Tax Rate	35.0%
18	State Tax Rate	6.5%
19	Pre-Tax WACC	11.8%
20		
21	Difference in Pre-Tax WACC	1.8%
22		
23	Projected Average Rate Base ($MM)[b]	$ 833.2
24		
25	**Difference in Gross Revenue Requirement Under ITC Ownership ($MM)**	
26	Difference from Change in Capital Structure ($MM)	$ 20.8
27	Difference from Credit Quality Savings ($MM)	(6.0)
28	**Total Difference in Gross Revenue Requirement Under ITC Ownership ($MM)**	**$ 14.9**
29		
30	Projected 12 Coincident Peak Load (GW) [b]	76.0
31		
32	**Difference in 2014 OATT Rate Under ITC Ownership ($/KwM)**	
33	Difference in OATT Rate from Change in Capital Structure ($/KwM)	$ 0.27
34	Difference in OATT Rate from Credit Quality Savings ($/KwM)	(0.08)
35	**Total Difference in 2014 OATT Rate Under ITC Ownership ($/KwM)**	**$ 0.20**

Note: Excludes one-time rate effect due to conversion to forward test year of $0.16 for ITC Arkansas

(a) Reflects average cost of debt assuming 3.5% on initial refinanced debt and midpoint of forecasted interest rate range on future debt

(b) Inputs provided by Entergy witness, Mr. Jay Lewis

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION OF ENTERGY ARKANSAS, INC., MID SOUTH TRANSCO LLC, ITC MIDSOUTH LLC, TRANSMISSION COMPANY ARKANSAS, LLC, AND ITC HOLDINGS CORP. TO ENTER TRANSACTIONS RESULTING IN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A NEW ARKANSAS UTILITY TO OWN EAI'S ELECTRIC TRANSMISSION FACILITIES	**DOCKET NO. 12-069-U**

ITC EXHIBIT CMB-11

AMENDED PROPOSED COMMITMENTS

AMENDED PROPOSED COMMITMENTS

The following proposal is made by the Entergy Arkansas Inc. ("EAI") and ITC to resolve Docket No. 12-069-U. This listing of conditions and commitments is intended to substitute for all those conditions and commitments made by the Applicants in any previous term sheet, public discussions (except those commitments made during a contested case hearing) and/or in Applicants' rebuttal testimony.

I. DEFINITIONS

"Actual WACC Effects" means the difference in EAI retail WACC as of December 5, 2011 and actual ITC WACC applied to the ITC Rate Base and adjusted for EAI retail impact only. This is used for benefits test(s) and true-up(s) during the Transition Period.

"Annual Review Period" means a calendar year within the Extension Period.

"Attachment O rate" means the MISO tariff Attachment O forward-looking formula, and resulting revenue requirement and transmission charges for ITC as approved by FERC in Docket No. ER12-2681.

"Estimated WACC Effects" means the difference in EAI retail WACC as of December 5, 2011 and estimated ITC WACC applied to EAI estimated transmission rate base and adjusted for EAI retail impact calculated in the retail regulatory filing to estimate retail rate effects of the Transaction. This is used for rate mitigation calculations.

"Extension Period" means the time period following the Initial Period, if any, during which the Rate Mitigation Plan continues in effect.

"FERC" means the Federal Energy Regulatory Commission.

"Initial Period" means the 5-year period starting at the close of the Transaction.

"ITC" means the ITC Midsouth operating company in Arkansas.

"ITC Ownership Benefit Calculation" means the benefits of ITC ownership as calculated in accordance with **Appendix B** to this term sheet.

"ITC Rate Base" means actual ITC rate base reflected in rates charged for transmission service that are passed through EAI retail rates.

"MISO" means the Midcontinent Independent System Operator, Inc.

"Rate Mitigation Plan" means use of funds over the Initial Period and Extension Period, if any, to offset certain rate effects of the Transaction.

"Regulatory Authority" means the Arkansas Public Service Commission.

"RTO" means Regional Transmission Organization.

"Transaction" means the Reverse Morris Trust transaction among ITC Holdings Corp., Entergy Corp., and affiliated entities through which a subsidiary of ITC Holdings Corp. will own the transmission assets formerly owned by the Entergy Operating Companies.

"Transition Period" means the period of time following close of the Transaction during which the Rate Mitigation Plan is in place, which begins with the Initial Period and includes the Extension Period, if any.

"WACC" means Weighted Average Cost of Capital in percentage terms.

II. EAI AND ITC MUTUAL PROPOSALS

A. Rate Mitigation – WACC Effects

1. **Initial Period:** ITC and EAI agree to implement a Rate Mitigation Plan over the Transition Period, which at a minimum will be the Initial Period but may be extended during the Extension Period as set forth below. The funds associated with the Rate Mitigation Plan for the Initial Period are specified in **Appendix A,** but may be modified in accordance with Subsection II.A.10 below.

2. **Extension Period:** If at the end of the Initial Period, ITC has not demonstrated that the annual ITC Ownership Benefit Calculation is greater than the annual Actual WACC Effects in the fifth year following the close of the Transaction, the Rate Mitigation Plan shall remain in place until such time as ITC has demonstrated that the annual ITC Ownership Benefit Calculation exceeds the annual Actual WACC Effects during an Annual Review Period. The Rate Mitigation Plan for the Extension Period will consist of annual funds that reflect 100% of the projected Actual WACC Effects net of the percentage of annual Actual WACC Effects offset by the ITC Ownership Benefit Calculation per the last calculation of such benefits.

3. **True Up of Initial Period:** If at the end of the Initial Period the annual ITC Ownership Benefit Calculation is not greater than the annual Actual WACC Effects in the fifth year following the close of the Transaction, there will be a true-up of the Actual WACC Effects for the Initial Period to the funds associated with the Rate Mitigation for the Initial Period specified in **Appendix A**. To the extent that Actual WACC Effects less the ITC Ownership Benefit Calculation exceeds the funds associated with the Rate Mitigation Plan for the Initial Period specified in **Appendix A**, additional rate mitigation for the difference will be put in place over the next two years (one-half of the additional rate mitigation in the sixth year following close of the Transaction and one-half of the additional rate mitigation in the seventh year following the close of the Transaction).

4. **True Up During Extension Period:** During the Extension Period, if any, if annual Actual WACC Effects less the ITC Ownership Benefit Calculation for the Extension Period exceed the rate mitigation funds provided during the Extension Period in accordance with Subsection II.A.2, additional rate mitigation funds for such difference will be put in place in the next calendar year.

5. **Review of Benefits By Third Party Evaluator:** The determination of whether the annual ITC Ownership Benefit Calculation exceeds annual Actual WACC Effects shall be made by a Third Party Evaluator in accordance with the methodology set forth in **Appendix B**. Beginning no earlier than the last year of the Initial Period and at any time during the Extension Period, ITC shall be permitted to initiate the Third Party Evaluator's assessment of the annual ITC Ownership Benefit Calculation to determine whether the annual ITC Ownership Benefit Calculation exceeds annual Actual WACC Effects. There shall be no limit as to the number of times or frequency that the Third Party Evaluator's assessment of the ITC Ownership Benefit Calculation may be initiated during the Extension Period. The Third Party Evaluator shall be selected by ITC and all costs associated with the Third Party Evaluator's services will be paid by ITC.

6. **Termination of Rate Mitigation:** If the Third Party Evaluator determines, in accordance with **Appendix B,** that the annual ITC Ownership Benefit Calculation exceeds annual Actual WACC Effects at either the end of the Initial Period or for any Annual Review Period, any obligations for rate mitigation terminates on the 30th day following the filing of the Third Party Evaluator's determination.

7. **EAI Treatment of Rate Mitigation Realized by ITC:** Any rate mitigation provided by ITC that is realized by EAI as part of the Rate Mitigation Plan will be passed through to EAI customers.

8. **Termination of EAI Contribution To Rate Mitigation:** If at the end of the 20th year following the close of the Transaction, the ITC Ownership Benefit

Calculation has not been found to exceed the annual Actual WACC Effects for an Annual Review Period, EAI's obligation to provide bill credits shall cease. ITC shall be obligated to provide all rate mitigation thereafter until such time as the ITC Ownership Benefit Calculation exceeds the annual Actual WACC Effects for an Annual Review Period.

9. **Measuring Estimated or Actual WACC Effects:** For purposes of measuring Estimated and Actual WACC Effects, in either the Initial Period or the Extension Period, EAI's WACC will be based on equity and capital structure as of the date of the Transaction's announcement (December 5, 2011), which is the basis for determining the amounts set forth in **Appendix A**.

10. **FERC Ordered Rate Construct Change:** If FERC issues an order that changes the formula rate or elements of the rate construct (including the forward looking application of the formula rate, authorized rate of return on equity, target capital structure, and annual true-up mechanism) for ITC, and which causes a change in ITC-WACC, then any rate mitigation shall be adjusted by an amount equivalent to the change in ITC-WACC caused by that FERC order.

11. **No Challenge To Rate Construct By Parties:** During the Initial Period, the Rate Mitigation Plan is conditioned on the parties to this proceeding in support of the Rate Mitigation Plan and the Regulatory Authority that approves the Rate Mitigation Plan not challenging the formula rate and elements of the rate construct (including the forward looking application of the formula rate, authorized rate of return on equity, target capital structure, and annual true-up mechanism) that are approved for ITC by the FERC in connection with the Transaction.

12. **Return On Equity:** During the Transition Period, ITC will not seek an approval from FERC to utilize an overall rate of return on equity that is above the prevailing return on equity level approved for use by Transmission Owners in MISO, except that if that return on equity level is less than 12.38% then ITC may seek approval from FERC to utilize a rate of return on equity up to 12.38 percent.

B. Rate Mitigation – Forward Test Year

1. EAI agrees to provide additional retail customers bill credits specified in **Appendix A** over the first three years of the Initial Period, which amount represents the estimated effects on retail customers of eliminating regulatory lag by implementing a forward test year during the Initial Period.

C. Transmission System Performance

1. **ITC and EAI Storm Plans:** Within 180 days after the closing of the ITC Transaction, EAI and ITC shall file with the Regulatory Authority new (separate) Emergency Response Plans specifically detailing their proposed

responses to tropical storms, hurricane and flood conditions, the manner in which coordination and communication between EAI and ITC will occur, how communication and coordination with State and local authorities will occur and all related matters.

2. **Vegetation Management Plans:** EAI and ITC, within 180 days after closing of the ITC Transaction, shall file with the Regulatory Authority their tree trimming/vegetation control plan for the EAI service territories. That plan must include expected expenditures broken down by EAI service territories and between ITC and EAI for transmission vegetation control versus distribution vegetation control. That plan should also detail the breakdown of responsibility for vegetation control as between EAI and ITC.

3. **System Hardening Plans:** ITC, one year after closing of the ITC Transaction, shall file with the Regulatory Authority its proposal for "hardening" of the former EAI backbone transmission systems.

4. **Joint Storm Drills:** ITC and EAI commit to conduct, no less than annually, joint storm drills, which will include the participation of other entities who are interconnected with ITC's transmission system who choose to participate, which address joint plans for responding to catastrophic storms.

D. Other Matters

1. **State Approvals:** The Regulatory Authority will have the right to reconsider its approval and public interest determination if the other jurisdictions, not including City of New Orleans or Missouri, issue an Order denying EAI the authority to complete the ITC Transaction.

2. **FERC Approval:** The Regulatory Authority will have the right to reconsider its approval and public interest determination if the FERC issues an Order denying Entergy and/or ITC the authority to complete the ITC Transaction.

3. **Most Favored Nations:** ITC and EAI will provide to each Regulatory Authority any contingency, condition or benefit that is provided for in any other Regulatory Authority's order approving the Transaction in any other jurisdiction provided such contingency, condition or benefit does not derive from circumstances or regulatory requirements unique to an individual jurisdiction and can be applied consistently across jurisdictions, and ITC and EAI receive comparable terms and consideration from the Regulatory Authority seeking to receive such contingency, condition or benefit.

4. **Requests For Relief:** Requests for relief in the joint application are granted to the extent not modified by this term sheet.

III. ITC PROPOSALS

A. **Jurisdiction Generally:** ITC is committed to operating in full compliance with all applicable legal and regulatory requirements, and working closely and collaboratively with the Regulatory Authority. ITC will operate subject to and in compliance with all state statutes and regulations that apply to it as an electric transmission only public utility in Arkansas.

B. **Books and Records**: ITC acknowledges that the Regulatory Authority has authority to review its books and records in accordance with the requirements of state law.

C. **Asset Transfers:** ITC shall not transfer any transmission assets located in Arkansas without the prior approval of the Regulatory Authority, in accordance with the requirements of state law.

D. **State ITC Representative:** ITC will designate an employee whose main work location and residence is in Arkansas to be a liaison on behalf of ITC to the Regulatory Authority. ITC also will designate personnel who will be available to participate in emergency operations coordination when needed.

E. **Requests for Information and Meetings:** Subject to reasonable notice, ITC will cooperate with Regulatory Authority requests for information and for ITC staff to attend Regulatory Authority meetings, technical conferences, and hearings.

F. **Transmission Projects:** On an ongoing basis, and at least annually regarding its annual capital investment program, ITC will share with the Regulatory Authority information about its planned or proposed transmission projects, including the rationale for planned or proposed projects, currently anticipated timing and cost of construction, and other material information about such projects. In addition, ITC will respond to inquiries from the Regulatory Authority regarding its transmission projects, will be open to and consider input from the Regulatory Authority regarding its transmission project plans, and support the Regulatory Authority's active participation in the regional transmission planning process.

G. **Annual Rate Posting:** On an annual basis, at least 15 days prior to the time that ITC posts its forecasted Attachment O rate with MISO, ITC shall provide to the Regulatory Authority a summary of that forecasted rate posting, including all expected rate impacts.

H. **Responses to Inquiries:** ITC commits that it will respond to data requests timely regarding its annual forecasted Attachment O rate posting with MISO and otherwise cooperate with the Regulatory Authority and their Staff in their analyses. ITC further agrees to make members of its staff available to the Regulatory Authority and its Staff to respond to inquiries and to explain the submission and the annual rate posting process.

I. **Summary of Rates Charged:** Annually, within 30 days after ITC submits its annual FERC Form No. 1 to FERC, ITC shall provide to the Regulatory Authority a summary of all rates charged by MISO to network transmission customers of ITC for the prior year.

J. **Litigation Expenses:** For issues in which Regulatory Authority has a justiciable interest and as provided by state law, ITC commits that it will annually fund up to $1.5 million (unless otherwise provided by applicable state law) the Regulatory Authority's reasonably necessary expenses for an effective review of any information or pleadings that ITC submits to the Regulatory Authority or to FERC, and complaints or actions filed by, or investigations or audits initiated by, the Regulatory Authority at FERC or its own jurisdiction related to transmission services provided by ITC to utilities that are subject to the retail jurisdiction of the Regulatory Authority. ITC also will continue to fund such necessary expenses as had been provided in state law if that state law is repealed or does not otherwise remain in force. This commitment is contingent upon ITC's ability to recover such costs in rates.

K. **Rate Filings:** ITC commits that it will review with the Regulatory Authority and/or Staff any rate filings initiated by it to FERC that would impact ITC's customers in Arkansas in advance to explain the rationale for such a filing.

L. **MISO Conditions:** ITC will abide by all applicable MISO conditions, identified in **Appendix A**. ITC will abide by this condition provided that: a) any exit fee associated with terminating membership in MISO be paid by electric consumers within the footprint served by ITC; b) any termination of membership in MISO also be approved by FERC; c) any termination of membership in MISO also not be disputed by another state Regulatory Authority or local authority in which ITC or one of its affiliates operates; d) if terminating membership in MISO, ITC is able to join a different RTO immediately upon its exit from MISO; and e) ITC shall retain all of its rights, state and federal, to appeal and/or seek other review of any decision or determination by the Regulatory Authority regarding ITC membership in an RTO, including the right to assert federal preemptive rights and seek related relief at the FERC and in the courts under applicable federal law.

M. **Transmission Project Commitment:** ITC will solicit input from the Regulatory Authority regarding transmission projects that should be studied and pursued. ITC will collaborate with the Regulatory Authority to pursue such projects, and take appropriate actions to study and construct such projects that fulfill ITC's transmission planning criteria, are approved through the necessary RTO planning processes, and receive other necessary regulatory approvals.

N. **Siting Authority:** ITC agrees that the Regulatory Authority has certification and siting authority for electric transmission, and will abide by any final Regulatory Authority order adopted exercising that authority, subject to ITC reserving any appeal rights provided under state law. However, this condition is not intended to preempt ITC's compliance with any federal statute or final order of the FERC.

ITC reserves all its rights to participate in proceedings to establish rules related to the Regulatory Authority's rights and authority, and reserves the right to appeal any rules that may be inconsistent with the applicable State and Federal laws, and otherwise reserves its rights to appeal orders issued pursuant to such rules.

O. **System Improvement Plan:** Within 1 year after the closing of the ITC Transaction, ITC shall submit to the Regulatory Authority a report on its analysis of the transmission system formerly owned by EAI and its related plan to improve the transmission system in Arkansas. Included in its analysis will be a study of congestion on the transmission system and an identification of transmission projects to mitigate such congestion. ITC will propose and support in the MISO planning process those transmission projects identified in the study that are expected to cost-effectively reduce congestion.

P. **ITC Responsibility for Transmission System:** ITC acknowledges and commits that, to the extent not otherwise preempted by federal law, after completion of the ITC Transaction, it will be fully responsible and accountable to the Regulatory Authority for the provision of safe, reliable, adequate and reasonable cost service to its customers in all respects related to planning and the provision of service for the transmission function. ITC shall also be responsible for coordination of operations with EAI as necessary.

Q. **ITC Local Presence:** ITC commits to maintain one or more office, warehouse, and/or pull-out facility locations in this state that will be staffed with ITC personnel.

R. **Civic and Charitable Support:** During the 3-year period immediately following closing of the Transaction, the subsidiaries of ITC Holdings Corp. that own the electric transmission facilities formerly owned by subsidiaries of Entergy Corp. will provide charitable contributions and other community support within the communities in which they operate (allocated among those jurisdictions in a reasonable manner and approximately commensurate in amount with each other), at a level comparable in the aggregate to the levels currently provided by ITC Holdings Corp. in its other service territories.

S. **Use of Local Workforce:** To the extent possible, and where such personnel or vendors satisfy ITC's standards related to quality, capability, cost efficiency, and equipment or other specifications, ITC will seek to utilize vendors, contractors, and personnel located in this state in its transmission system maintenance and capital investment initiatives.

T. **Goodwill:** ITC confirms its commitment that it will not seek to recover goodwill related to the Transaction.

U. **Transaction Costs:** ITC will not seek to recover its Transaction costs unless such recovery is approved by FERC, based on a finding that the benefits of the Transaction outweigh such costs.

V. Workforce Commitment: For a period of 3 years following closing of the Transaction, ITC Holdings Corp. will not implement layoffs of employees performing work on ITC's behalf at a level or in a manner that is not approximately commensurate with layoffs of employees performing work on behalf of ITC Holdings Corp.'s other subsidiary operating companies.

W. ERSC Participation: ITC will support retention of the Entergy Regional State Committee's existing authority over cost allocation and construction of transmission upgrades for the five-year transition period after the Entergy Operating Companies join MISO and the transitional framework conditionally approved by FERC in Order No. ER12-480-000.

IV. EAI Transmission Cost Rate Mechanism And Incremental Costs

A. Deferred Costs

1. **Deferred Costs:** To the extent there is any difference in transmission costs actually incurred after the closing of the Transaction and transmission costs reflected in currently applicable rates, this difference would be deferred for recovery until new base rates take effect for EAI and applied to the mechanism the Regulatory Authority determines to be appropriate for transmission cost recovery in EAI's pending rate case.

B. Incremental Costs

1. Incremental Costs: EAI agrees that it will not seek to recover incremental costs associated with the Transaction. While this excludes all external costs, there are certain internal costs that currently are being charged to the Transaction that are not incremental to the EAI's ongoing revenue requirements. EAI proposes that it be permitted to retain these costs in rates but subject to an after-the-fact review by the Regulatory Authority that these costs were prudently incurred for purposes unrelated to the Transaction.

APPENDIX A: SUPPLEMENTAL PROPOSED COMMITMENTS FOR ARKANSAS

I. ITC AND EAI PROPOSALS

A. Rate Mitigation – WACC Effects

Subject to Section II.A.10 in the Amended Proposed Commitments, during the Initial Period, ITC and EAI shall provide $110.7 million in Rate Mitigation Funds, which amount represents an offset of 100% of the estimate of WACC Effects on retail rates during the Initial Period. The $110.7 million of Rate Mitigation Funds will be provided to retail and wholesale customers via $110.7 million in wholesale rebates or retail bill credits.

B. Forward Test Year

EAI agrees to provide retail customers $6.9 million in additional retail bill credits over the first three years after Transaction close.

C. Other Entergy Retail Regulator Decisions

ITC and EAI will provide the Commission, as soon as they receive them, decisions of any of the other Entergy Retail Regulators, and the FERC, approving, denying, or otherwise impacting the ITC Transaction.

II. ITC PROPOSALS

A. MISO Conditions:

ITC will abide by all applicable MISO conditions as set forth in the Commission's Order No. 68 in Docket No. 10-011-U.

ITC has reviewed the MISO conditions in Order 68 and believes that conditions 1, 2 (a) and (b), 3, 8, 9, 10, 12, 13, 14 (a) and (b), 15, 16, 17, 18 and 19 are inapplicable to ITC, have already been satisfied or are beyond the control of ITC.

1. Condition 2 (c):

> *EAI shall be assigned, separately and apart from the other OpCos, to a Transmission Pricing Zone; Load Zone; Auction Revenue Rights Zone; and Local Resource Zone. EAI shall agree that the Commission, sua sponte or upon motion of any party to this proceeding, may reconsider its conditional approval of the transfer of control if FERC does not approve all of these separate EAI arrangements/zones.*

ITC affirms its commitment on the Transmission Pricing Zone Condition 2(c) as addressed in the affidavit of Joseph L. Welch attached as EAI Exhibit HTM-9 to the August 24, 2012 compliance testimony of Hugh T. McDonald in Docket No. 10-011-U.

2. Condition No. 4:

> *Should EAI become a member of MISO, EAI shall agree that it will not exit MISO without first filing an application with the Commission seeking its approval for a change of control of its transmission assets. EAI will otherwise retain all of its rights, state and federal, to appeal or seek review of or relief from the decision of the Commission.*

ITC will abide by this condition provided that: a) any exit fee associated with terminating membership in MISO be paid by electric consumers within the footprint served by ITC Arkansas; b) any termination of membership in MISO also be approved by FERC; c) any termination of membership in MISO also not be disputed by another state regulatory commissions or local authority in which ITC or one of its affiliates operates; d) if terminating membership in MISO, ITC is able to join a different RTO immediately upon its exit from MISO; and e) ITC shall retain all of its rights, state and federal, to appeal and/or seek other review of any decision or determination by the Commission regarding ITC' membership in an RTO, including the right to assert federal preemptive rights and seek related relief at the FERC and in the courts under applicable federal law.

3. Condition No. 5:

> *Should EAI become a member of MISO, EAI shall agree that the Commission, sua sponte or upon the motion of any party, may direct EAI to exit MISO under the terms of the Memorandum of Understanding or the TOA. EAI will otherwise retain all of its rights, state and federal, to appeal or seek review of or relief from the decision of the Commission.*

ITC will abide by this condition provided that: a) any exit fee associated with terminating membership in MISO be paid by electric consumers within the footprint served by ITC Arkansas; b) any termination of membership in MISO also be approved by FERC; c) any termination of membership in MISO also not be disputed by another state regulatory commissions or local authority in which ITC or one of its affiliates operates; d) if terminating membership in MISO, ITC is able to join a different RTO immediately upon its exit from MISO; and e) ITC shall retain all of its rights, state and federal, to appeal and/or seek other review of any decision or determination by the Commission regarding ITC' membership in an RTO, including the right to assert federal preemptive rights and seek related relief at the FERC and in the courts under applicable federal law.

4. Condition No. 6:

> *Should EAI become a member of MISO, EAI shall remain under the Commission's jurisdiction, to the extent not otherwise preempted by FERC, with respect to retail electric rates and all related electric facility operations, facility siting, financing, and reliability.*

ITC will abide by this condition to the extent such jurisdiction is applicable under state law to ITC as an electric transmission only utility in Arkansas.

5. Condition No. 7:

> *Should EAI become a member of MISO, EAI shall agree that the Commission, sua sponte or upon the motion of any party to this proceeding, may, after notice and hearing, reconsider and, if necessary, reverse any approval of the transfer of control if:*
>
> *a) The terms of FERC's approval of the modifications to the MISO Tariff to transition EAI into MISO are materially changed such that the revised terms will have a material adverse impact on EAI's retail ratepayers; or*
>
> *b) Any of the foregoing conditions are not fully adopted, incorporated or realized.*

ITC assumes that *"reverse any approval of the transfer of control"* in this condition refers to a transfer of control of the transmission assets to MISO and not to a transfer of control of the transmission assets from EAI to ITC. Based on that assumption, ITC will abide by this condition provided that: a) any exit fee associated with terminating membership in MISO be paid by electric consumers within the footprint served by ITC Arkansas; b) any termination of membership in MISO also be approved by FERC; c) any termination of membership in MISO also not be disputed by another state regulatory commissions or local authority in which ITC or one of its affiliates operates; d) if terminating membership in MISO, ITC is able to join a different RTO immediately upon its exit from MISO; and e) ITC shall retain all of its rights, state and federal, to appeal and/or seek other review of any decision or determination by the Commission regarding ITC' membership in an RTO, including the right to assert federal preemptive rights and seek related relief at the FERC and in the courts under applicable federal law.

6. Condition No. 11:

> *Should EAI become a member of MISO, the Commission shall retain full audit rights for costs associated with EAI's membership in MISO.*

ITC will abide by this condition, which ITC understands to mean that ITC will provide information upon request by the Commission related to the costs incurred as a result of ITC's participation in MISO that are ultimately reflected in retail rates in Arkansas. ITC's agreement to abide by this condition is not intended to grant the Commission any authority it does not currently have under state law nor give up any rights that ITC may have under federal or state law.

7. Condition No. 14 (c) and (d):

> *Should EAI become a member of MISO, no later than three years after joining MISO and every two years thereafter, assuming EAI continues as a MISO member, EAI shall file with the Commission a detailed report providing the following information:*

> *c. Any significant changes in FERC RTO policies, rules or regulations, MISO requirements, Day 2 market conditions, or other regulatory or market structure components; and*
> *d. An estimate of the costs to exit MISO after the end of the five-year transition period or a specified time thereafter and to transition to a new operating environment such as a different RTO,*

ITC will abide by this condition.

APPENDIX B: CALCULATION OF ITC OWNERSHIP BENEFITS

I. DEFINITIONS

"**Actual WACC Effects**" means the difference in EAI retail WACC as of December 5, 2011 and actual ITC WACC applied to the ITC Rate Base and adjusted for EAI retail impact only.

"Annualized Cost of ITC Economic Projects" means the project cost of the ITC Economic Projects based on MISO's determination divided by 40 years.

"Asset Care Plan" means work yet to be completed under EAI's "2013 T&D Reliability Plan" at the time the Transaction closes.

"Economic Base Case" means any models of the state of the transmission assets owned by ITC MidSouth at the time the Transaction closes. The presumed state of the transmission assets in the ITC Midsouth footprint is the transmission assets at the time of the Transaction's close modified to include the projects in **Attachment 1 to Appendix B** that receive approval through MISO's planning process as identified on that list. At the time any study is initiated, the most recently available models produced by MISO will be used to represent the systems and data outside of the transmission assets owned by ITC Midsouth. To the extent these models include systems and data outside the MISO footprint, such systems and data will be represented as in the MISO models.

"**Extension Period**" means the time period following the Initial Period, if any, during which the Rate Mitigation Plan continues in effect.

"Initial Period" means the 5-year period starting at the close of the Transaction.

"ITC Base Case" means any models of the state of the transmission assets contained within the footprint of ITC Midsouth to be used in this benefits test. The state of the transmission assets for the ITC Midsouth footprint is the transmission assets contained within the footprint of ITC Midsouth at the time any study is initiated, modified by all transmission projects approved by MISO for integration into the ITC Midsouth footprint. At the time any study is initiated, the most recently available models produced by MISO will be used to represent the systems and data outside of the transmission assets in the ITC Midsouth footprint. To the extent these models include systems and data outside the MISO footprint, such systems and data will be represented as in the MISO models.

"ITC Economic Projects" means projects proposed by ITC and included in an approved MISO transmission plan as a Market Efficiency Project.

"**ITC Ownership Benefit Calculation**" means the benefits of ITC ownership as calculated in accordance with section III.A below.

"**ITC Rate Base**" means actual ITC rate base reflected in rates charged for transmission service that are passed through EAI retail rates.

""**MISO**" means the Midcontinent Independent System Operator, Inc.

"Rate Mitigation Plan" means use of funds over the Initial Period and Extension Period, if any, to offset certain rate effects of the Transaction.

"Reliability Base Level" means the 2012 results using the SGS Methodology for given indices on the transmission system as owned and operated by Entergy Corp., and its affiliated entities.

"SGS Report" means the *Transmission Reliability Benchmarking Study* published by SGS Statistical Services.

"**SGS Methodology**" means the methodologies employed in the development of the SGS Report, or similar methodologies, to determine average circuit sustained outages and average circuit outage duration.

"**Subject Year**" means the most recent year for which complete data is available for a measure. Subject Year may vary by measure.

"Transaction" means the Reverse Morris Trust transaction among ITC Holdings Corp., Entergy Corp., and affiliated entities through which a subsidiary of ITC Holdings Corp. will own the transmission assets formerly owned by the Entergy Operating Companies.

"**Transition Period**" means the period of time following close of the Transaction during which the Rate Mitigation Plan is in place, which begins with the Initial Period and includes the Extension Period, if any.

"Third Party Evaluator" means an individual or entity (together with any necessary subcontractor(s)) who, in ITC's sole discretion, is qualified to oversee and/or administer the benefits test.

"**WACC**" means Weighted Average Cost of Capital in percentage terms.

II. CALCULATION

A. Overview

There are three components of the test that shall be applied to determine whether the benefits of ITC's ownership of transmission offset the Actual WACC Effects:

1. **<u>Improved System Performance:</u>** The showing of an improvement in system reliability, incremental to the Reliability Base Level, as indicated through the system performance metrics described herein; and

2. **Improved System Economics:** The showing of an improvement in system economics, incremental to the Economic Base Case, as indicated through the economic benefit metrics described herein.

3. **Not Readily Quantifiable Benefits**: The Transaction produces benefits that are not readily quantifiable. For purposes of calculation, this is assumed to be 10% of Actual WACC Effects.

B. Methodology of Test for Improved System Performance

1. Calculation

For a given year, the Improved System will be the sum of:

a. Percentage Improvement in Average Circuit Sustained Outages,
b. Percentage Improvement in Average Circuit Outage Duration, and
c. Percentage Remediation of Asset Care Plan

2. Explanation Of Calculation Elements

a. Percentage Improvement in Average Circuit Sustained Outages

Utilizing the SGS Methodology, the Percentage Improvement in Average Circuit Sustained Outages is the Subject Year actual ITC annual average circuit sustained outages reduction as compared to the Reliability Base Level average circuit sustained outages. This metric is calculated as the percentage by which the Subject Year average circuit sustained outages is less than the average circuit sustained outages observed in the Reliability Base Level. Percentage Improvement in Average Circuit Sustained Outages will be evaluated for each transmission pricing zone.

b. Percentage Improvement in Average Circuit Outage Duration

Utilizing the SGS Methodology, the Percentage Improvement in Average Circuit Outage Duration is the Subject Year actual ITC annual average circuit outage duration reduction as compared to the Reliability Base Level average circuit outage duration. This metric is calculated as the percentage by which the Subject Year average circuit outage duration is less than the average circuit outage duration observed in the Reliability Base Level. Percentage Improvement in Average Circuit Outage Duration will be evaluated for each transmission pricing zone.

c. Percent Remediation of Asset Care Plan

The Percent Remediation of Asset Care Plan for the Subject Year will be calculated as the total reduction in Asset Care Plan achieved by the end of the Subject Year measured in task or unit depending on the activity. Percent Remediation of Asset Care Plan will be evaluated for each transmission pricing zone.

3. Implementation Roles and Procedures

Generic Simplified Example: Percentage improvement or remediation for one metric = (Base– ITC results or remaining work)/Base. If the base for a metric was 100 and ITC in results or remaining work for that metric in a Subject Year = 95, then improvement or remediation = (100 – 95)/100 = 5%. If the metrics were X, Y and Z respectively, the total Improved System Performance would X + Y + Z).

C. Methodology of Test for Improved System Economics

1. **Calculation:** For a given year, the Improved System Economics will analyze the incremental improvement of the economic performance in the ITC Base case as compared to the Economic Base Case. The arithmetic annual average of the sum of the following quantities over 40 years will be the Improved System Economics for the year:
   a. Congestion and Fuel Savings Benefits,
   b. Operating Reserves Savings Benefits,
   c. System Planning Reserve Margin Benefits,
   d. Transmission Line Losses Benefits,
   e. Generation Investment Benefits, and
   f. Future Transmission Investment Benefits

(Year 1 Total = a + b + c + d + e + f for year 1, Year 2 Total = a + b + c + d + e + f for year 2, Improved System Economics = Average of Year 1 Total, Year 2 Total, …, Year 40 Total)

2. Explanation Of Calculation Elements

a. Congestion and Fuel Savings Benefits

To the extent the ITC Base Case allows for a more efficient dispatch of generation resources, opening of markets to competition and spreading the benefits of low cost generation throughout the ITC Midsouth footprint, as compared to the Economic Base Case, these benefits will be counted as Congestion and Fuel Savings Benefits. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient use of generation resources as well as removal of reliability must run status for certain generators. The Congestion and Fuel Savings Benefits will be evaluated on a MISO-wide basis and allocated to each transmission pricing zone in the proportion that these benefits are shown to be received by that transmission pricing zone.

b. Operating Reserves Savings Benefits

To the extent the ITC Base Case reduces operating reserve costs for the ITC Midsouth footprint as compared to the Economic Base Case, these benefits will be counted as Operating Reserves Savings Benefits. These benefits may include the savings from retirement of generation units previously needed to support reserve margins Operating Reserves Savings Benefits be evaluated for each transmission pricing zone.

c. System Planning Reserve Margin Benefits

To the extent the ITC Base Case reduces transmission congestion as compared to the Economic Base Case, thereby reducing the footprint planning reserve margin and decreasing the amount of generation required to meet the planning reserve margin, this defers new generation. The value of these benefits will be counted as System Planning Reserve Margin Benefits. System Planning Reserve Margin Benefits arising from avoided/deferred generation capacity will be evaluated for each transmission pricing zone.

d. System Losses Reduction

To the extent the ITC Base Case reduces overall system losses as compared to the Economic Base Case, this reduces the generation needed to serve the system losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs. The value of the reduced future generation capacity needs benefits will be counted as System Loss Benefits. System Loss Benefits will be evaluated for each transmission pricing zone.

e. Optimization of Generation Locations

To the extent the ITC Base Case reduces or defers the need for constructing new generating plants in load pockets as compared to the Economic Base Case, this reduces the generation capital investment cost needed to serve the customers. The value of these benefits for the ITC Midsouth footprint will be counted as Generation

Investment Benefits. These benefits accruing from increased deliverability of capacity will be evaluated for each transmission pricing zone.

f. Future Reliability Transmission

To the extent that ITC Economic Projects eliminate or defers the need for future reliability transmission investments, this reduces the total transmission investment cost needed to serve the customers. The value of this elimination or deferral for each Transmission pricing zone in the ITC Midsouth footprint will be counted as future transmission investment benefits.

3. Implementation Roles and Procedures

a. Performance of the Improved System Economics Test

The valuation metrics used in the Improved System Economics Test used above were developed by MISO for their MVP analysis (https://www.midwestiso.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf). This MISO methodology that has been vetted through a stakeholder process.

b. Input Assumptions of the Improved System Economics Test

In any year, all input assumptions of the ITC Base Case and the Economic Base Case will be consistent with the most recent assumptions of the most recent MTEP and/or MVP analyses to be performed by MISO. These assumptions include, but are not limited to, fuel costs, US Environmental Protection Administration mandates/Renewable Power Standards, load forecasts and the attendant uncertainties, transmission topology (unless otherwise specified herein related to Entergy or ITC Midsouth footprint) and generation futures.

III. OVERALL TEST IMPLEMENTATION FRAMEWORK

A. Establishment of the portion of ITC's Revenue Requirement Subject to Mitigation

ITC Ownership Benefit Calculation:

For a given year:

a) Not Readily Quantifiable Benefits (assumed as 10% of Actual WACC Effects)
b) plus benefits demonstrated through Improved System Performance multiplied by Actual WACC Effects (capped at 45% of Actual WACC Effects)

c) plus benefits demonstrated through Improved System Economics
d) less Annualized Cost of ITC Economic Projects
e) less Actual WACC Effects

If the ITC Ownership Benefit Calculation in any given year for which the calculation can be made is greater than or equal to zero, the Rate Mitigation Plan shall terminate on the 30th day following the filing of the Third Party Evaluator's determination.

The benefits test will be performed by the Third Party Evaluator near the end of the Initial Period such that the results will be available to ITC and EAI at the conclusion of the Initial Period. Thereafter the test may be applied for any period at the sole discretion of ITC.

ATTACHMENT 1 TO APPENDIX B: PROJECT LIST

Planned Projects Included in Economic Base Case

Project Name	LE	Proposed ISD (Planning)
NLR Westgate - NLR Levy: Reconductor 115 kV Line	EAI	2013 Summer
Fordyce: Relocate capacitor bank to 115 kV bus	EAI	2014 Summer
Sheridan South 500 kV FG Upgrade: Mabelvale 500 kV Substation replace 3 breakers, 13 switches, and 2 line traps	EAI	2014 Summer
Sheridan South 500 kV FG Upgrade: Sheridan 500 kV Substation replace 11 switches, and 6 line traps	EAI	2014 Summer
Sheridan South 500 kV FG Upgrade: White Bluff 500 kV Substation replace 5 switches, and 2 line traps	EAI	2014 Summer
Sheridan South 500 kV FG Upgrade: Eldorado 500 kV Substation replace 1 switch and 2 line traps	EAI	2014 Summer
Camden McGuire - Camden North 115kV Line: Construct New Line	EAI	2014 Summer
LV Bagby to Reed: Construct new 230 kV line and operate at 115 kV	EAI	2014 Summer
Woodward to Pine Bluff Watson Chapel: Reconductor line	EAI	2014 Summer
Calico Rock-Melbourne - Upgrade 161kV Line	EAI	2014 Winter
Hot Springs Hamilton (Albright) - Carpenter Dam: Construct new 115 kV Line and convert Mountain Pine South to ring bus stations.	EAI	2015 Summer
Pine Bluff Voltage Support Project: Phase 2 Woodward: Construct 230 kV ring bus and convert White Bluff to Pine Bluff Arsenal D to Woodward 115 kV line to 230 kV	EAI	2015 Summer
White Bluff: Reconfigure 500 kV Station and construct 230 kV ring bus	EAI	2015 Summer
Woodward - Pine Bluff West - Pine Bluff McCamant: Reconductor 115 kV	EAI	2015 Summer
Woodward-115 kV Bus Reconfiguration	EAI	2015 Summer
HS EHV-HS Industrial: Upgrade Terminal Equipment	EAI	2015 Summer
HS Industrial-HS Union Carbide: Upgrade Terminal Equipment	EAI	2015 Summer
HS Union Carbide-HS East: Upgrade Terminal Equipment	EAI	2015 Summer
Norfork-Calico Rock : Upgrade 161 kV Line	EAI	2016 Summer
AECC L&D 2 to Gillett: Construct new 115 kV Line	EAI	2016 Summer
Mabelvale: Replace 500-115 Autos	EAI	2016 Summer
Mossville - Cut-in line 616 (Nelson to Carlyss 138 kV) into Mossville 138 kV Substation	EGSL	2013 Summer
Five Points to Line Tap 281 to Line 247 Tap- Upgrade 69 kV line	EGSL	2014 Summer
Copol to Bourbeaux: Upgrade 69 kV line	EGSL	2014 Winter
McManus to Brady Heights - Upgrade 69 kV line	EGSL	2016 Summer
Sorrento Upgrade 138/115 kV Auto and upgrade Gonzales - Sorrento 138 kV Line	EGSL/ELL	2014 Summer
Southeast LA Coastal Improvement Plan: Phase 3 Construct Oakville to Alliance 230kV Line Add 230 - 115 kV Autotransformer at Alliance Substation	ELL	2012 Summer

NE Louisiana Improvement Project - Phase 2 Oakridge to new Dunn Substation - Construct new 115 kV Line (1272 ACSS) Add 115 kV breakers at Dunn	ELL	2013 Summer
Golden Meadow to Leeville 115 kV - Rebuild/relocate 115 kV transmission line	ELL	2013 Winter
Mt. Olive: Add Shunt Reactor	ELL	2013 Winter
NM6: Modify Ninemile switchyard for interconnection	ELL	2014 Winter
NM6: Upgrade Michoud breaker N9803	ELL	2014 Winter
NM6: Upgrade Ninemile to Southport 230 kV transmission line No.1	ELL	2014 Winter
NM6: Upgrade Ninemile to Southport 230 kV transmission line No.2	ELL	2014 Winter
Ray Braswell - Wyndale 115kV Line: Construct New 260 MVA Construct new 115 kV Switching Station between Byram and Terry Wyndale SS to be designed for future 230-115 kV auto and distribution facilities	EMI	2013 Summer
Baxter Wilson to S.E. Vicksburg - Upgrade 115 kV line	EMI	2015 Summer
Breakers at Hollandale and Belzoni (close normally-open point)	EMI	2015 Summer
Deweyville (JNEC) - Add 69 kV capacitor bank	ETI	2012 Summer
College Station SS: Create emergency tie point with ERCOT (asynchronous)	ETI	2012 Summer
Conroe Area Switching Station: tie lines Longmire to Fish Creek and Conroe to Woodhaven into new switching station	ETI	2013 Summer
Upgrade Jacinto - Splendora 138 kV Line	ETI	2015 Summer
Alden 138 kV Substation: Add Capacitor Bank	ETI	2015 Summer
Construct new China to Amelia 230kV line	ETI	2016 Summer
Upgrade Splendora to Apollo 138 kV Line	ETI	2016 Summer
Ponderosa to Grimes: Construct new 230 kV Line Add 345-230 kV Auto at Grimes Add 230-138 kV Auto at Ponderosa	ETI	2016 Summer