REDACTED – PUBLIC VERSION

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF A SHOW CAUSE ORDER	)	
DIRECTED TO ENTERGY ARKANSAS, INC.	)	
REGARDING ITS CONTINUED MEMBERSHIP	)	
IN THE CURRENT ENTERGY SYSTEM	)	CASE NO: 10-11-U
AGREEMENT, OR ANY SUCCESSOR	)	
AGREEMENT THERETO, AND REGARDING	)	
THE FUTURE OPERATION AND CONTROL	)	
OF ITS TRANSMISSION ASSETS	)	

SUPPLEMENTAL INITIAL TESTIMONY

OF

CRAIG R. ROACH, Ph.D.
BOSTON PACIFIC COMPANY, INC.

ON BEHALF OF SOUTHWEST POWER POOL, INC.

JULY 12, 2011

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I. QUALIFICATIONS

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

A. My name is Craig R. Roach. I am the President as well as the Founder of Boston Pacific Company, Inc. (Boston Pacific). My business address is 1100 New York Avenue, NW, Suite 490 East, Washington, DC 20005.

Q. What is your relationship to Southwest Power Pool, Inc. (SPP)?

A. For seven years, my colleagues and I have served as independent advisors to the Board of Directors of SPP. SPP has now hired me as an independent expert witness for this proceeding. The views expressed herein are my own.

Q. Please summarize your educational background.

A. I earned my Ph.D. in Economics from the University of Wisconsin and my Bachelor of Science Degree in Economics, *cum laude*, from John Carroll University. I currently serve on the Advisory Board to the University of Wisconsin's Department of Economics.

Q. Please summarize your professional background.

A. I have 36 years of experience working on investments in, policies for, and litigation concerning the electricity and natural gas businesses and other energy businesses. Boston Pacific is a consulting and investment services firm specializing in the electricity and natural gas businesses. For 24 years, Boston Pacific has served the full range of stakeholders: public utility commissions, regional transmission organizations, competitive power suppliers, electric utilities, electric and gas marketers, gas pipeline companies, electric transmission companies, trade associations, government agencies, and energy consumers. Prior to Boston Pacific, I was an Economist with the U.S. Congressional Budget Office and a Project Manager with ICF Incorporated, an energy and environmental consulting firm.

Q. Do you have experience as an expert witness?

A. Yes. I have extensive experience as an expert witness, having submitted testimony, affidavits, or comments to the Federal Energy Regulatory Commission (the FERC) in more than thirty proceedings, to public utility commissions in twenty-four states plus the District of Columbia (some on multiple occasions), before three Canadian Provincial Boards, in arbitrations, in state and federal courts, to a City Council, and before a Congressional Subcommittee. A complete list of my testimony is contained in Attachment No. CRR-1. Also shown therein is a list of my speeches and articles on issues in the electricity and natural gas businesses, and in other energy businesses.

Q. Please provide some examples of Boston Pacific's recent work.

A. Boston Pacific now does substantial work as an independent monitor for electricity markets and competitive solicitations. As already indicated above, since 2004 Boston Pacific has served as an independent advisor to the SPP Board of Directors. Boston Pacific has also served since 2004 as independent monitors for many competitive solicitations including those in the District of Columbia, Delaware, Illinois, Maryland, New Jersey, Ohio, Oklahoma, Oregon, Pennsylvania, Virginia, and elsewhere; in this work, Boston Pacific generally reports to the State Regulatory Commission.

Boston Pacific also has conducted substantial financial and market consulting for power investments throughout North America and in about two dozen countries around the world. For example, we currently serve as financial and market consultants to the U.S. Department of Energy Loan Guarantee Program.

II. PURPOSE AND SUMMARY OF MY TESTIMONY

Q. What is the purpose of your Testimony?

A. The purpose of my Testimony is to review *An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO* ("Entergy Evaluation Report") which is used to support its proposal to join the Midwest Independent System Operator (MISO) instead of joining the Southwest Power Pool Regional Transmission Organization (SPP RTO). While at the outset I want to compliment Entergy for deciding to join an RTO in the first place, I think Entergy, on balance, made the wrong choice. In my view, the SPP RTO is the better choice for Arkansas ratepayers as well as for ratepayers in the other Entergy States.

Q. Why did Entergy make the wrong choice?

A. Entergy made the wrong choice for at least two reasons. The first is that Entergy reversed the finding by Charles River Associates (CRA) that joining SPP would result in greater quantifiable benefits for ratepayers than joining MISO. Entergy did this by making "adjustments" to CRA's analysis that are not sufficiently credible. The second is that Entergy did not accurately assess the strategic advantages of joining the SPP RTO.

Q. Let's discuss your first point that Entergy inappropriately reversed CRA's finding. Who is CRA?

A. CRA is an independent consultant that conducted a series of studies on the quantifiable benefits of Entergy joining an RTO.

Q. Where was CRA's latest finding presented?

A. CRA presented its latest finding in its March 2011 Report. Table One below summarizes CRA's estimate of Net Benefits from joining SPP or joining MISO – note that these are benefits to the entire Entergy area, not just the Entergy Operating Companies.

Table One

CRA's Estimates of Net Benefits to the Entergy Area

(Present values for 2013 to 2022 in millions)

	Join SPP[1]	**Join MISO**[2]
Trade Benefits	$891	$737
Administrative Costs	($230)	($209)
Net Benefits	$661	$529
Transmission Cost Allocation	($937) to $23	($782)
Net benefits After Allocation	($276) to $684	($254)

CRA breaks the net benefits into three major categories. Trade Benefits are the first category and they reflect reductions in the cost of producing electricity from area power plants and from making sales and purchases of electricity. Table One shows that CRA found the present value of Trade Benefits from joining SPP to be $891 million while that for joining MISO was $737 million. In other words, the Trade Benefits from joining SPP exceed those from joining MISO by $154 million (or 21%).

The second category shown in Table One is the Administrative Costs for participating in either the SPP RTO or MISO. CRA shows these to be $230 million for SPP and $209

[1] Charles River Associates, *Cost-Benefit Analysis of Entergy/Cleco Power or Entergy Arkansas Joining the Midwest ISO, Addendum Study,* March 10, 2011 ("CRA March 2011 CBA") at page 10.
[2] Ibid. at page 11.

million for MISO. Netting out these Administrative Costs from the Trade Benefits means that the Net Benefits from joining SPP would be $661 million as compared to $529 million from joining MISO. Again, CRA finds that the Net Benefits from joining SPP exceed those from MISO by $132 million or 25%.

Finally, CRA tries to account for the allocation of transmission costs to the Entergy area from SPP or MISO. There is a huge range of transmission cost allocation given for SPP, but just a single number for MISO. If we deduct this cost allocation for transmission, CRA finds that the Net Benefits After Allocation (a) would range from negative $276 million to a positive $684 million for joining SPP and (b) would be a negative $254 million for joining MISO. Since the Net Benefits After Allocation from joining MISO are negative – meaning the costs exceed the benefits – the choice would be clearly in favor of joining SPP if Entergy were to join an RTO. Again, this is why I say the latest finding from CRA, the independent consultant, was that the quantitative benefits would favor Entergy joining SPP if it joined an RTO.

Q. You said that Entergy reversed the CRA finding?

A. Yes. Table Two below shows Entergy's estimate of the net benefits to the Entergy Operating Companies for joining MISO or SPP. Note that these are benefits to just the Entergy Operating Companies, not to the entire Entergy area as in CRA's analysis.

Table Two

Entergy's Estimates of Net Benefits to the Entergy Operating Companies[3]

(Present values for 2013 to 2022 in millions)

	Join SPP	**Join MISO**
Trade Benefits	$747	$817
Administrative Costs	($340)	($195)
Other Benefits	$646	$770
Net Benefits	$1,053	$1,393
Transmission Cost Allocation	($209) to $59	($327) to $0
Net benefits After Allocation	$844 to $1,112	$1,066 to $1,393

Q. How did Entergy reverse the CRA verdict?

A. Entergy did this by making five "adjustments" to the benefits and costs. Just to show how significant the changes were, consider that with the Entergy "adjustments," MISO was found to have positive Net Benefits After Allocation of well over one billion dollars. Specifically, with its "adjustments," Entergy estimated that joining MISO would generate Net Benefits After Allocation in a range from $1.066 billion to $1.393 billion. So, Entergy's "adjustments" took the estimate of Net Benefits After Allocation from CRA's negative $254 million up to as high as positive $1.393 billion – that is a dramatic change. To be fair, the change for SPP was big, too. The Net Benefits After Allocation from joining SPP, after the Entergy "adjustments," were estimated to be in the range of $0.844 billion to $1.112 billion.

Q. Do you believe that Entergy's five "adjustments" are sufficiently credible to justify reversing CRA's conclusion?

[3] Entergy Evaluation Report at page 15.

A. No. I find that the five Entergy "adjustments" are either based on oversimplified analysis and unsupported assumptions, or so poorly explained that they are not sufficiently credible to reverse CRA's conclusion that the benefits of joining SPP are likely to be greater than those for joining MISO.

Q. Please summarize the first of Entergy's "adjustments."

A. The first "adjustment" is to Trade Benefits. As noted above, CRA estimated the Trade Benefits from joining SPP to be $154 million higher than from joining MISO. Entergy's "adjustment" (along with the "base case" change described below) reverses the direction of the difference to favor MISO by $70 million – that is a swing in Trade Benefits of $224 million.

The primary purpose of Entergy's "adjustment" is said to be to allocate the Trade Benefits to just the Entergy Operating Companies and, thereby, to exclude the Trade Benefits to others in Arkansas or in the other Entergy states.[4] Since these "others" are presumably tax-paying, job-sustaining or job-creating businesses, and ratepayers in Arkansas or the other States, surely the Arkansas Commission would want to seriously consider these Trade Benefits when it rules on which RTO to join. In this sense, Entergy's "adjustment" is simply not helpful – the Commission should not ignore Trade Benefits to others.

Moreover, how does an allocation of Trade Benefits reverse the choice of which RTO to join? The analytic culprit is obvious: when joining SPP, Entergy found that 66% of

[4] Ibid. at page 55.

Trade Benefits went to the Entergy Operating Companies while when joining MISO 84% would go to those companies. Entergy provides no credible explanation for the disparity.

Q. Please summarize Entergy's second "adjustment."

A. Entergy's second "adjustment" was to change the "base case" used to compare these scenarios, a change which Entergy finds further favors joining MISO. The change is to model EAI as if it were separate from the other Entergy Operating Companies.[5] Logically, this simple change in starting point should add equally to the benefits of joining either RTO, but it does not, and Entergy provided no credible explanation.

Q. Please summarize the third "adjustment."

A. The third "adjustment" is to the Administrative Costs of participating in either SPP or MISO. Based on estimates provided by SPP and MISO, the Administrative Costs used by CRA were quite close: $230 million for SPP and $209 million for MISO.[6] In sharp contrast, Entergy assumes a major difference in costs: $340 million for SPP and $195 million for MISO.[7] The Entergy estimate of SPP operating costs is based on an oversimplified analysis which asserts that operating costs are solely a function of the size of the RTO. Moreover, without any detailed or credible analysis, Entergy increased the cost of implementing SPP's Day 2 Market from the $105 million budget approved by the

[5] Entergy Evaluation Report, Technical Appendix at page TA-20.
[6] CRA March 2011 CBA at Appendix A, Tables 29-30.
[7] Entergy Evaluation Report at page 10.

SPP Board to $200 million.[8] And, just as arbitrarily, Entergy reduced MISO's recorded Administrative Cost for 2009 by $55 million (or [redacted]%) for use in its analysis.

Q. Please summarize Entergy's fourth "adjustment."

A. The fourth "adjustment" is to Transmission Cost Allocation. I have three concerns with Entergy's "adjustment." One, while Entergy added its presumed cost allocation for unidentified transmission investments SPP might make, Entergy did not offset these costs with added Trade Benefits that might result from those investments. Two, Entergy did not include any investments that would be required to meet MISO's "comparability" standard, and yet MISO itself indicates that these investments could be substantial. Three, Entergy's presumed cost allocation through the Unintended Consequence provision is not credible because such an allocation would require a showing of benefits which Entergy did not do.

Q. Please summarize Entergy's fifth "adjustment."

A. The fifth "adjustment" is meant to add Other Benefits that Entergy thought were not assessed in the CRA analysis. By Entergy's reckoning, these Other Benefits would add $646 million to the benefits of joining SPP, but add a much larger amount – $770 million – to the benefits of joining MISO. These benefits dealt with reductions in regulation service, contingency reserves, and planning reserves. I agree these benefits are possible with an RTO, but my primary concern is that Entergy admits it failed to take account of the deliverability of reserves from MISO to Entergy when estimating these Other

[8] Ibid. at page 74. Note that another difference between the CRA Administrative Cost estimates and the Entergy estimates is that Entergy's estimates apply only to the Entergy Operating Companies, while CRA used administrative costs for the whole Entergy area.

Benefits. Another concern is that Entergy's "adjustments" were based on grossly oversimplified analysis – again, for example, Entergy assumed load alone dictates some of these benefits.

Q. What is the bottom line of your review of Entergy's attempt to reverse CRA's finding?

A. It is an unsuccessful attempt because none of the five "adjustments" are sufficiently credible to reverse CRA's conclusion. Therefore, the Arkansas Commission should rely on the latest result from the independent consultant which shows the SPP RTO is the better choice.

Q. Let's discuss the second reason you believe Entergy chose the wrong RTO.

A. Again, my second reason is that Entergy did not accurately assess the strategic advantages of joining the SPP RTO.

Q. Please describe the strategic advantages you see with joining the SPP RTO.

A. Arkansas ratepayers and Entergy ratepayers as a whole will find five strategic advantages to joining SPP.

Q. What is the first strategic advantage of joining the SPP RTO?

A. The first strategic advantage is that, because of the well-defined and well-respected role of the SPP Regional State Committee (RSC), the Arkansas Commission (and the other Entergy State Commissions) will have a much better opportunity to act on behalf of its ratepayers in the SPP RTO than in MISO. Put simply, in the SPP RTO, the RSC has explicit responsibilities and decision-making authority. There is no comparable organization in MISO; the Organization of MISO States or OMS is an external group with no such responsibilities and authorities.

Note that Carl Monroe, SPP's Executive Vice President and Chief Operating Officer, provides a full account of this benefit as well as other governance benefits in his Testimony in this proceeding.

Q. What is the second strategic advantage of joining the SPP RTO?

A. The second strategic advantage is that the transmission link between Entergy and SPP is much stronger than that between Entergy and MISO in both physical and transactional terms.

With respect to physical strength, three SPP members who operate under SPP's Tariff and participate in SPP's energy market share nine interconnection points with Entergy representing a capacity of approximately 4,300 MVA;[9] the three are AEP West, Oklahoma Gas and Electric, and Empire District. When Cleco, City of Lafayette, and the Southwest Power Administration are added, the number of interconnection points increases to forty-five and the capacity would be over 14,000 MVA.[10] In sharp contrast, the transmission link between Entergy and MISO used by CRA is along a single contract path with capacity of approximately 1,000 MW.[11] The implication is that, whatever the

[9] Response to AG 12-3.
[10] Response to Staff 23-1.
[11] Response to Staff 23-4.

reliability and cost benefits are of joining SPP, they are more likely to be realized than those from joining MISO because of this stronger transmission link.

With respect to transactional strength, my concern is that the single-path link between Entergy and MISO is entangled in three substantial disputes. One, the Entergy-to-MISO link is governed by an Interchange Agreement among Ameren, AECI, and Entergy Arkansas. That Interchange Agreement must be extended, but it has not been extended so we cannot know the terms going forward. Without knowing the terms going forward, it is difficult to know whether the promised reliability and cost benefits of joining MISO will be realized. Two, Ameren currently is a member of MISO, but the Missouri State Commission has asked Ameren to justify its continued participation. If Ameren were no longer a member of MISO, it would complicate Entergy's effort to join MISO – Entergy would no longer be interconnected to a MISO Member. And, again, without knowing Ameren's status in MISO, it is difficult to know whether the promised reliability and cost benefits of joining MISO will be realized. Three, the Joint Operating Agreement between SPP and MISO is in dispute at the FERC and, if Entergy joins MISO, that dispute could intensify, and may be a precursor to disputes with TVA and others going forward. The core of the ongoing dispute would be about loop flows; note that loop flows also would need to be addressed if Entergy joined SPP, but it would be less of an issue. It appears that FERC has ruled on legal terminology in the Joint Operating Agreement dispute, but not on the compensation MISO would have to pay SPP for loop flows. Without a resolution on compensation, we cannot know the net benefits, if any, of Entergy joining MISO.

Q. What is the third strategic advantage of joining the SPP RTO?

A. The third strategic advantage of joining the SPP RTO is that SPP has no plans for a capacity market while MISO does. This is important because, given a high-profile decision by the FERC on a case involving the New Jersey Board of Public Utilities, creation of a capacity market can lead to the FERC being at odds with generation capacity decisions by the Arkansas Commission and by the other Entergy State Commissions. In the extreme, if Entergy chose to participate in the MISO market, being at odds with the FERC could mean that Arkansas ratepayers would have to pay twice for capacity. At a minimum, it should be made clear that Entergy's assertion that it could both opt out of the MISO capacity market, and still participate in that market from time to time when it chooses, is not a real option today– there simply is not that kind of flexibility in established capacity markets like the one in PJM.

Q. What is the fourth strategic advantage of joining the SPP RTO?

A. The fourth strategic advantage is that, given current regulatory and market conditions, SPP's greater reliance on natural-gas fired capacity could yield both reliability and cost advantages as compared to MISO's greater reliance on coal-fired capacity. I make this point in response to Entergy's assertion that MISO being "predominantly coal" is guaranteed to bring diversity benefits. There are no guarantees either way. If Entergy joined the SPP RTO, 58% of the capacity would be natural gas- or oil-fired and 27% would be coal-fired. In contrast, if Entergy joined MISO, natural gas- and oil-fired capacity would be lower (35% vs. SPP's 58%) and coal-fired capacity would be much higher (48% vs. SPP's 27%).[12]

One regulatory condition raising substantial concern about coal-fired power is the U.S. EPA's court-ordered campaign to enforce four air pollution regulations. Both SPP and MISO may suffer shutdowns of power plants that become too expensive to run with the new regulations, but MISO would be hit harder. For example, a study by the Brattle Group concluded that up to 12 GW of coal units might be shut down in MISO while the shutdowns in SPP would be lower than 1 GW.[13] A study by NERC reported that, with the EPA regulations, reserve margins could be reduced in both SPP and MISO, but, again, MISO would be hit harder. The point is that these EPA regulations will have an impact on resource adequacy in both SPP and MISO, but the impact in MISO is expected to be more harsh. From this, we can conclude that SPP's greater reliance on natural gas-fired capacity has been a strategic advantage thus far in terms of mitigating the impact of EPA's regulation.

One market condition igniting widespread hope for ample, low-cost natural gas is the Shale Gas Revolution which refers to the fact that new technologies for finding and producing natural gas have opened up significant reserves and, thereby, have increased supply and reduced prices significantly. If the Shale Gas Revolution continues to hold down natural gas prices, SPP's greater dependence on natural gas-fired capacity could yield direct cost savings – using more natural gas can directly reduce the cost of power to

[12] Entergy Evaluation Report at page 81.
[13] The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, at page 32.

ratepayers. However, there are no guarantees and natural gas prices could be much higher than expected. If natural gas prices do go higher rather than lower, there still is a strategic advantage in joining SPP for Entergy Arkansas: with higher natural gas prices, sales of Entergy Arkansas' coal and nuclear power might be more profitable in natural gas-dependent SPP than in coal- and nuclear-dependent MISO. Driving this point home is the fact that, in SPP, natural gas prices now set the real-time energy price 62%[14] of the time while natural gas-, oil- and dual-fired units set prices in MISO only 23%[15] of the time.

Another strategic advantage of dependence on natural gas-fired power is that it can better accommodate swings in production from wind and other intermittent forms of generation.

Q. What is the fifth strategic advantage of joining the SPP RTO?

A. The fifth strategic advantage of joining the SPP RTO is that the transmission planning process and transmission cost allocation method are driven by benefits before and after transmission investments are made. Three points document this. One, a transmission investment must be shown to be needed to comply with reliability standards or to

[14] Southwest Power Pool, *2010 State of the Market Report*, May 10, 2011, at page 11.
[15] Potomac Economics, *2010 State of the Market Report Midwest ISO*, May 2011, at page 41. Note that more than one fuel type may be setting prices when a constraint is binding. MISO and SPP handle this situation differently when calculating marginal fuel percentages. For example in MISO, when a coal plant sets the price in an unconstrained area and a gas plant sets the price in a constrained area in the same interval, the result is double counting with 2 units on the margin in that interval. Therefore, the total percentage for fuel types at the margin in MISO is greater than 100%. This means that the 23% value reported for MISO would be even lower if this double counting did not occur. This is not the case in SPP, where the marginal fuel types do sum to 100%. Using the same example with SPP's calculation methodology, the coal plant would be assigned 0.5 and the gas plant would be assigned 0.5, summing to 1 unit on the margin in that interval as opposed to 2.

otherwise generate benefits before it can be included in SPP's Integrated Transmission Plan and, thereby, proposed for funding.

Two, the Highway/Byway cost allocation rule, which provided that all market participants share in the cost of projects consisting of 300 kV or higher, was a rule based on studies that showed all parties benefitting from these high voltage investments. In contrast, benefits studies suggested that lower voltage investments above 100kV and below 300kV be allocated one-third regionally and two-thirds locally. Note that this cost allocation method was developed and approved by the SPP RSC.

Three, after transmission investments are made, there is an ongoing process to assure equity in cost allocation. This is commonly called the Unintended Consequences process.

Benefits also seem to drive much of MISO's transmission planning and cost allocation. However, SPP's Unintended Consequences process is one advantage over MISO because MISO does <u>not</u> have a process to align costs and benefits after the fact at the instigation of a market participant or the RSC.

Q. What is the bottom line of your review of the strategic advantages of Entergy joining the SPP RTO versus those for MISO?

A. The bottom line is that Entergy failed to properly assess these strategic advantages. On top of the advantage in quantified net benefits, the Arkansas Commission can find further support for choosing the SPP RTO in these five strategic advantages.

III. THE ARKANSAS COMMISSION SHOULD RELY ON THE INDEPENDENT CONSULTANT'S LATEST ANALYSIS WHICH SHOWED THAT JOINING THE SPP RTO WOULD HAVE GREATER RATEPAYER BENEFITS THAN JOINING MISO.

A. In its March 2011 study, CRA compared the net benefits from joining SPP to those from joining MISO and found that joining SPP would be likely to provide greater net benefits to the Entergy region.

Q. Has there been an independent, third-party study of the benefits of joining SPP versus the benefits of joining MISO?

A. Yes, in March of 2011 CRA produced an assessment of the benefits to the Entergy region of joining SPP and MISO. This was the latest in a series of studies that CRA had performed, but the first such study to simultaneously compare the benefits of joining either of these two RTOs.

Q. What were CRA's conclusions?

A. CRA's conclusions can be best seen below in Table Three. This table shows the net present value of various benefits and costs incurred by the Entergy region should it join SPP or MISO. The table also shows the difference between the SPP case and the MISO case.

Table Three

CRA's Estimates of Net Benefits to the Entergy Area

(Present values for 2013 to 2022 in millions)

	Join SPP	Join MISO	Difference
Trade Benefits	$891	$737	$154
Administrative Costs	($230)	($209)	($21)
Net Benefits	$661	$529	$132
Transmission Cost Allocation	($937) to $23	($782)	($155) to $805
Net benefits After Allocation	($276) to $684	($254)	($22) to $938

Q. How does CRA categorize benefits and costs?

A. CRA breaks the benefits and costs into three major categories: Trade Benefits; Administrative Costs; and Transmission Cost Allocations.

Q. What are Trade Benefits?

A. Trade Benefits reflect reductions in the cost of producing electricity from area power plants and from making sales and purchases of electricity as a result of combined commitment and dispatch. Table Three above shows that CRA found the present value of Trade Benefits from joining SPP to be $891 million while that for joining MISO was $737 million. So CRA found the Trade Benefits from joining SPP would exceed those from joining MISO by $154 million or 21%.

Q. What did CRA find with respect to Administrative Costs?

A. As can be seen in the table, CRA shows Administrative Costs to be $230 million for SPP and $209 million for MISO; Administrative Costs are the costs of membership in the SPP RTO or MISO. When CRA subtracts the Administrative Costs from Trade Benefits, CRA reports a net benefit to joining SPP of $661 million as compared to $529 million from joining MISO. Again, CRA shows the net benefits from joining SPP exceed those from MISO by $132 million or 25%.

Q. What did CRA find with respect to Transmission Cost Allocation?

A. CRA faced considerable uncertainty when trying to determine what Entergy might pay for regional transmission projects in SPP or MISO. For SPP, they were given a range of values from a cost of $937 million to a benefit of $23 million. This reflects a range of scenarios from the worst case (in which Entergy pays for all Regional costs) to the best (in which Entergy pays for Regional costs beginning in January 2013, does not pay for Balanced Portfolio or Priority Projects, and actually allocates some of its own costs to SPP Members).[16] MISO's estimate is a single point estimate and reflects the cost allocation of paying for a share of MISO's current Multi-Value Projects.

Q. What is CRA's ultimate conclusion regarding the net benefits of joining SPP versus the net benefits of joining MISO?

A. CRA finds that benefits of joining SPP range from negative $276 million to positive $684 million on a net present value basis. This compares to a negative $254 million cost to joining MISO. Since the single estimate for MISO is negative, these numbers clearly show that joining SPP could provide more net benefits than joining MISO. They also show that the advantage to SPP over MISO could be significant, up to $938 million dollars in the "best case" transmission cost scenario.

[16] CRA March 2011 CBA at page 17.

B. In its May 2011 Evaluation Report, Entergy made several "adjustments" to reverse CRA's finding, but these "adjustments" are not sufficiently credible to reverse CRA's finding.

Q. Did Entergy produce a similar comparison of net benefits in its May report?

A. Well, Entergy did not do a start-from-scratch analysis. Instead, Entergy made "adjustments" to the CRA analysis. Table Four below shows Entergy's "adjusted" net present value of various benefits and costs for joining either RTO as shown in its May report. Note that one of Entergy's "adjustments" was to add a category of "Other Benefits."

Table Four

Entergy's Adjusted Net Benefits to the Entergy Operating Companies

(Present values for 2013 to 2022 in millions)

	Join SPP	Join MISO	Difference
Trade Benefits	$747	$817	($70)
Administrative Costs	($340)	($195)	($145)
Other Benefits	$646	$770	($124)
Net Benefits	$1,053	$1,393	($340)
Transmission Cost Allocation	($209) to $59	($327) to $0	$118 to $59
Net benefits After Allocation	$844 to $1,112	$1,066 to $1,393	($222) to ($281)

Q. What were Entergy's conclusions?

A. As can be seen in Table Four, despite using CRA's March study as its starting point, Entergy managed to overturn CRA's verdict. According to Entergy, joining MISO now is expected to produce Net Benefits After Allocation of between $1,066 million and

$1,393 million while joining SPP would produce Net Benefits After Allocation of between $844 million and $1,112 million. The scale of Entergy's increase in the estimated benefits of joining MISO is notable. Recall that CRA estimated a <u>net</u> <u>loss</u> of $254 million for joining MISO. Entergy, through its "adjustments," estimates a <u>net</u> <u>gain</u> ranging from $1,066 million to $1,393 million.

Q. How did Entergy make its estimates of benefits?

A. Again, Entergy started with CRA's March results, then proceeded to make a series of "adjustments" to the data.

Q. Were these "adjustments" credible?

A. No. These "adjustments" are not sufficiently credible to justify reversing CRA's conclusion. I find that several of these "adjustments" are either based on oversimplified analysis or unsupported assumptions, or so poorly explained that they cannot be understood. Entergy makes five "adjustments" affecting, in turn: (a) Administrative Costs; (b) the entities included in the benefits calculation; (c) the definition of the base case; (d) Transmission Cost Allocation; and (e) Other Benefits.

C. Entergy makes three "adjustments" to the Administrative Cost estimates which are based on oversimplified analytic methods and unsupported assumptions. These "adjustments" take CRA's $21 million MISO Administrative Cost advantage and change it to a $145 million advantage.

Q. What was the first "adjustment" Entergy made to the CRA net benefits analysis?

A. The first "adjustment" Entergy made to CRA's analysis was to the Administrative Costs of participating in either SPP or MISO.

Q. How did CRA estimate Administrative Costs?

A. CRA used Administrative Cost estimates provided by SPP and MISO.[17] CRA presumably did this because the RTOs themselves are in the best position to analyze their own cost data and budget projections to formulate accurate Administrative Cost estimates that reflect their own specific circumstances and market designs.

Q. What components did CRA include?

A. In its analyses, CRA broke the Administrative Cost estimates into the following components: (a) RTO Administrative Costs – the capital (including startup costs) and operating costs of running the markets and administering the Tariff, (b) FERC Charges – annual charges required by the FERC, and (c) Internal Capital/Labor costs – internal costs for Entergy over and above the RTO Administrative Costs. CRA then subtracted from these costs the costs that were avoided as a result of no longer paying for the services of the Independent Coordinator of Transmission or the ICT. The result is the

[17] CRA March 2011 CBA at page 16.

total Administrative Costs for Entergy joining an RTO. CRA shows these cost figures for each year of the study period (2013-2022) and calculates a 10-year present value.[18]

Q. What were CRA's estimates of Administrative Costs?

A. The 10-year present value for the Administrative Costs used by CRA for SPP and MISO were quite close: $230 million for SPP and $209 million for MISO.[19]

Q. How did Entergy "adjust" CRA's estimates?

A. In its Evaluation Report, Entergy claims that the SPP estimate is not in line with other RTOs' historical Administrative Costs.[20]

To reflect this opinion, Entergy makes three "adjustments" to CRA's Administrative Costs for joining SPP; Entergy also makes these same three "adjustments" to the Administrative Costs of joining MISO. These "adjustments" significantly impact the Administrative Cost numbers – Entergy estimates that the Administrative Costs for joining SPP would actually be $340 million rather than the $230 million used by CRA – a $110 million or 48% increase.[21] In contrast, Entergy reduced the Administrative Costs for joining MISO to $195 million from CRA's $209 million – a 6.7% decrease.[22]

Q. You said Entergy made three "adjustments." Let's discuss each of them in turn. Please summarize Entergy's first "adjustment" to the Administrative Cost estimates.

[18] Ibid. at Appendix A, Tables 29 and 30.
[19] Ibid.
[20] Entergy Evaluation Report at page TA-29.
[21] Entergy Evaluation Report at page 10 and CRA March 2011 CBA at Appendix A, Table 29.
[22] Entergy Evaluation Report at page 10 and CRA March 2011 CBA at Appendix A, Table 30.

A. I mentioned before that CRA broke the Administrative Costs into several line items. Entergy's first "adjustment" is to one of those line items – "RTO Administrative Costs." Because Entergy believes SPP's cost estimate is not in line with other RTOs' historical costs, Entergy discards CRA's "RTO Administrative Costs" and makes its own estimates for SPP and MISO.[23]

Q. Please explain Entergy's method for calculating "RTO Administrative Costs" for SPP and MISO.

A. Entergy bases its entire analysis on the 2009 Administrative Costs of four RTOs. Entergy gathered the total annual 2009 Administrative Costs and total annual 2009 load figures for ISO-New England, New York ISO, Midwest ISO (with a reduction), and PJM. Then, for each of the four RTOs, Entergy plotted the annual 2009 administrative dollar values on the y-axis against the total annual 2009 load values on the x-axis, resulting in four points on a graph. Entergy then placed a regression line on the graph to represent the relationship between total annual load and total annual Administrative Costs. [redacted].[24]

[23] Entergy Evaluation Report at page 106.
[24] Entergy Confidential Work Papers, *HSPM_Admin_Estimate* ("Confidential HSPM Admin Estimate") and EAI Data Request Responses to the Arkansas Electric Cooperative Corporation's 3rd Set, Question No.: AECC 3-13.

Q. You noted a "reduction" in MISO's 2009 Administrative Cost.

A. Yes. Rather than use the actual 2009 cost for MISO, Entergy reduced the actual cost by $55 million or [redacted]%.[25] Entergy claims it did this to purge the cost of MISO's Day 2 market development cost, but I think it is an arbitrary change in a recorded data point that is one of just four data points Entergy relies upon.

Q. What was the impact of this first "adjustment" to the Administrative Cost estimates of joining SPP and MISO?

A. This one "adjustment" increases the present value of Administrative Costs for joining SPP from $230 million to $361 million, an increase of $131 million or 57%.[26] On the other hand, this "adjustment" increases MISO's Administrative Costs by only $31 million or 15% from $209 million to $240 million.[27]

Q. Do you believe this first "adjustment" to the Administrative Costs was reasonable?

A. No. Entergy's method gave absolutely no consideration to SPP's specific circumstances – market design, capital costs, operating costs, etc. Entergy's estimates were instead based solely on the 2009 Administrative Costs of four other RTOs – again, noting the reduction to MISO's cost – and the presumption that scale (as measured by annual load) is the only factor driving those costs. Entergy's single-year, single-line method greatly oversimplifies what drives RTO costs and, therefore, is inadequate for deriving such

[25] Ibid.
[26] CRA March 2011 CBA at Appendix A, Table 29 and EAI Data Request Responses to the Southwest Power Pool, Inc.'s 1st Set ("SPP 1st Set"), Question No.: SPP 1-25.
[27] CRA March 2011 CBA at Appendix A, Table 30 and SPP 1st Set at Question No.: SPP 1-25.

important cost figures, especially given that it results in a huge swing in the relative benefits of joining MISO versus joining SPP.

Entergy also in no way accounts for what I will term “late bloomer” benefits that SPP might realize. Given that the late bloomer benefits are also relevant to Entergy’s second “adjustment” to the Administrative Cost estimates, I will discuss what I mean in more detail when I discuss Entergy’s second “adjustment.”

Q. Please summarize Entergy’s second “adjustment” to the Administrative Cost estimates.

A. The second “adjustment” Entergy makes is to add the full startup costs of SPP’s Integrated Marketplace to the Administrative Cost estimate of joining SPP.

Given that startup costs are typically included in the “RTO Administrative Costs” discussed above, Entergy must be presuming that the 2009 Administrative Costs for the other four RTOs used to derive SPP’s costs did not include any startup costs. This presumption is evidenced by Entergy’s arbitrary reduction to MISO’s 2009 recorded cost. As a result, Entergy’s estimate for MISO’s Administrative Cost reflects this presumed reduction in 2013, while the full startup costs are added on top of Entergy’s estimate of SPP’s Administrative Costs discussed above.[28]

Q. Did Entergy use the SPP Board-approved startup budget for the startup cost estimate?

A. No. Entergy did not use the SPP Board-approved budget for startup costs; instead Entergy almost doubled the Board-approved estimate, increasing it from $105 million to

[28] SPP 1st Set at Question No.: SPP 1-25.

$200 million.[29] Entergy based this "adjustment" on the fact that other RTOs required higher development costs, and experienced schedule delays and cost overruns above and beyond their initial estimates.[30]

Q. What was the impact of this second "adjustment" to the Administrative Cost estimates of joining SPP and MISO?

A. By adding SPP's startup costs, Entergy adds an additional $57 million to its estimate of the total present value of Administrative Costs it will incur by joining SPP, $[redacted] of which results from increasing SPP's startup budget from $105 million to $200 million.[31]

Therefore, this "adjustment" increases the present value of Administrative Costs for joining SPP from $361 million to $418 million, while the Administrative Costs to joining MISO stayed the same at $240 million.[32]

Q. Do you believe this second "adjustment" to the Administrative Costs was reasonable?

A. No. Entergy's doubling of the startup costs for SPP's Day 2 market is not adequately explained or justified – other than to point out that MISO, CAISO, and ERCOT had higher costs and suffered cost overruns and schedule delays. In an answer to a data

[29] Entergy Evaluation Report at page 74.
[30] Ibid. at pages 24, 74, and TA-30 through TA-31.
[31] Confidential HSPM Admin Estimate and SPP 1st Set at Question No.: SPP 1-25.
[32] SPP 1st Set at Question No.: SPP 1-25.

request, Entergy stated that it used the lowest actual startup cost figure of MISO, CAISO, and ERCOT, which was $200 million (CAISO).[33]

Furthermore, Entergy's "adjustments" for "RTO Administrative Costs" (the first "adjustment" to Administrative Costs) and the second "adjustment" here for startup costs in no way accounts for the "late bloomer" benefits of which SPP is taking advantage. SPP is taking advantage of at least three types of late bloomer benefits.

One, SPP can and has drawn from the lessons learned from other RTO experiences (including MISO) in terms of design, implementation, and operation. Three examples illustrate this point. One, SPP used other RTO market designs as a starting point for its Day 2 Market – the Integrated Marketplace – choosing the best practices for each major element.

Two, SPP has learned from the problems other RTOs have experienced. For example, the Enhanced Combined-Cycle modeling feature has caused delays and overruns in ERCOT and CAISO. For this reason, this feature is not in the base design of SPP's Integrated Marketplace – it will be deferred until the base design is implemented. More broadly, SPP's design proposal includes no major untested design features. Note, too, that SPP has studied and will attempt to avoid problems MISO has encountered in startup and operations such as: (a) MISO's settlement problems with its Revenue Sufficiency Guarantee (RSG) payments, and (b) MISO's Day-Ahead Margin Assurance Payment (DAMAP) problems – also known as the "loophole" rule.

[33] SPP 1st Set at Question No.: SPP 1-1.

Three, SPP recently announced Memorandums of Understanding with PJM and ERCOT. SPP states that these RTOs will share with SPP "their expertise, experience, and lessons learned from development, implementation, and operation of their markets."[34]

Q. What is the second of your three examples of late bloomer benefits?

A. Second, SPP has learned lessons from designing and operating its own EIS Market, which was launched in February 2007. The EIS Market is similar in design to what will be the Real-Time Balancing Market in the Integrated Marketplace. SPP, therefore, has experience operating markets that use security constrained economic dispatch software.

Q. What is the third late bloomer benefit?

A. Third, SPP's design philosophy for the Integrated Marketplace was to spend a lot of upfront time developing a very detailed design before implementing the software. SPP took this approach to avoid schedule and cost overruns that plagued ERCOT and CAISO.

Q. Please summarize Entergy's third "adjustment" to the Administrative Cost estimates.

A. The third "adjustment" Entergy makes to the Administrative Cost estimates reflects the fact that the Administrative Costs discussed to this point were for the entire Entergy region rather than just for the Entergy Operating Companies. Entergy makes this third

[34] Southwest Power Pool, *SPP Board Approves Integrated Marketplace Budget, PJM and ERCOT Agree to Share Market Expertise*, April 26, 2011.

"adjustment" to allocate the Administrative Costs to each of its Operating Companies; Entergy makes this allocation on a load ratio share basis.[35]

Q. What was the impact of this third "adjustment" to the Administrative Cost estimates of joining SPP and MISO?

A. Of the $418 million of Administrative Costs to the Entergy region for joining SPP, Entergy estimates that its Operating Companies will incur $340 million.[36] Of the $240 million of Administrative Costs to the Entergy region of joining MISO, Entergy estimates that its Operating Companies will incur $195 million.[37] Note that an 81% share is used for both SPP and MISO.[38]

Q. Do you believe this third "adjustment" to the Administrative Costs was reasonable?

A. No. I believe that the numbers of most interest to the Commission are the numbers for the whole Entergy region that include other Arkansas businesses and customers.

Q. When taken together, what is the overall impact of the three Administrative Cost "adjustments?"

A. Taking these three "adjustments" together, Entergy takes a $21 million Administrative Cost advantage for joining MISO from CRA's analysis ($230 million for SPP vs. $209 million for MISO) and turns it into a $145 million Administrative Cost advantage for

[35] Entergy Evaluation Report at page 106.
[36] Entergy Evaluation Report at page TA-32.
[37] Ibid.
[38] EAI Data Request Responses to the Arkansas Electric Cooperative Corporation's 4th Set, Question No.: AECC 4-4.

joining MISO ($340 million for SPP vs. $195 million for MISO).[39] This is a huge "adjustment" in the context of CRA's cost benefit analysis – it wipes out the $132 million Net Benefit Advantage CRA estimated for SPP.[40]

Q. Are there any advantages to paying administrative costs to SPP rather than to MISO that were not identified by Entergy?

A. Yes. SPP's location in Little Rock means that the administrative costs that Entergy will spend in joining SPP will stay in Arkansas, while the administrative costs Entergy will spend to join MISO will leave the State.

Q. How would you characterize this advantage?

A. I would characterize it as an economic impact or economic development benefit for the State if Entergy joined SPP rather than joining MISO.

Q. Is it common to assess such economic development benefits?

A. Yes. For example, we found two recent studies of economic impact conducted by the University of Arkansas; one estimated the economic impact of developing the Fayetteville shale gas resource[41] while the other assessed the economic impact of Medicaid spending in Arkansas.[42]

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[39] Entergy Evaluation Report at page 10 and CRA March 2011 CBA at Appendix A, Tables 29 and 30.
[40] CRA March 2011 CBA at pages 10-11.
[41] *Projecting the Economic Impact of Fayetteville Shale Play for 2008-2012*, Center for Business and Economic Research, Sam M. Walton College of Business, University of Arkansas, March 2008. Accessed July 8, 2011. Sourced from the Arkansas Economic Development Commission. http://arkansasedc.com/media/1708/fayetteville%20shale%20economic%20impact%20study%20(2008-2012).pdf ("Shale study"). The study uses an economic input-output known as IMPLAN to determine the economic effects of direct corporate spending on the development of Fayetteville Shale in Arkansas.
[42] *The Economic Impact of Medicaid spending in Arkansas*, Center for Business and Economic Research, Sam M. Walton College of Business, University of Arkansas, May 2010. Accessed July 8, 2011. Sourced from the Arkansas Economic Development Commission.

Q. How did these two University of Arkansas studies define economic benefit?

A. The shale gas study started with the direct impact of the money spent to develop the shale gas resource. Then the study added in (a) "indirect impact" in terms of "supply chain" spending – for example, suppliers to the project buying goods and services in the State and (b) "induced impact" in terms of "personal expenditures" – for example, workers spending their pay on goods and services in the State.

Q. What did the studies find?

A. As expected, the studies found a ripple effect through the Arkansas economy. That is, every dollar spent directly created more than a dollar of economic activity and for every job directly related to the project there were additional jobs related to the added economic impact.

Q. What was the size of that "ripple effect" in the Arkansas State economy?

A. The study on the effect of investment in Fayetteville shale gas in Arkansas found that (a) for every one dollar spent directly on the project, $1.45 of total economic activity was created in Arkansas, and (b) for every one direct job there were a total 2.5 jobs related to the full economic activity.[43] For the longer period of 2008 to 2012, the study forecast about the same multiplier.[44] For 2007, the study stated the following:

> To provide a baseline of economic activity, expenditures and employment in the year 2007 were investigated. These impacts were substantial: $1.8 billion of

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http://cber.uark.edu/The_Economic_Impact_of_Medicaid_Spending_in_Arkansas_Executive_Summary.pdf ("Medicaid study"). The study uses an economic input-output known as IMPLAN to determine the economic effects of direct spending on Medicaid in Arkansas.

[43] Shale study at ii.

[44] Ibid. at iii.

> direct expenditures led to total economic output of $2.6 billion and employment of 9,533 people.[45]

Q. What did the study on Medicaid spending find in terms of the multiplier effect?

A. The Medicaid study found that each dollar of direct spending resulted in about $1.60 of total spending and that with each direct job there were 1.45 jobs in total.[46]

Q. Should the Arkansas Commission consider this possible economic impact in Arkansas as an added advantage for joining SPP?

A. Yes. I think it is fair to consider these economic development benefits as one additional benefit of joining SPP that could not be generated by joining MISO. I would not let it be the sole reason to join SPP, but it is fair to add it to the list of advantages for joining SPP.

D. Entergy unnecessarily narrowed the focus from benefits for the entire Entergy region to benefits for only the Entergy Operating Companies, and, then, found these Companies would get only 66% of the regional benefits in SPP, but 84% in MISO.

Q. What was the second "adjustment" that Entergy made to CRA's analysis?

A. Entergy adjusted CRA's "Trade Benefits," which, as already noted, reflect lower production and purchased power costs as a result of combined commitment and dispatch. The "adjustment" was through an analysis called the Operating Company Allocation Analysis or OAA.

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[45] Ibid. at ii.
[46] Medicaid study at iii.

Q. What did Entergy claim was the purpose of this "adjustment?"

A. Entergy claimed that the purpose of this "adjustment" was to allocate Trade Benefits identified by CRA to the Entergy Operating Companies.

Q. Why did Entergy claim this was necessary?

A. CRA's analysis looked at benefits to the entire Entergy region. This region also contains Independent Power Producers or IPPs, qualifying facilities or QFs, and other load serving entities. Entergy has specifically identified 13 balancing authorities, 8 load-serving entities and several IPPs and QFs who operate in its region.[47]

Q. What was the result of this "adjustment?"

A. Recall that CRA predicted Trade Benefits to the Entergy region from joining SPP of $891 million on a present value basis. For joining MISO, CRA estimated benefits of $737 million. As a result of the OAA, Entergy determined that the Trade Benefits to just the Entergy Operating Companies were $589 million for joining SPP versus $619 million for joining MISO.[48] With the OAA, Entergy's "adjustment" turns a $154 million SPP advantage into a $30 million MISO advantage, a swing of $184 million.

Q. Does Entergy explain why the OAA flipped the choice from SPP to MISO?

A. No. With SPP, Entergy asserts that its operating companies get only 66% of the Trade Benefits while, with MISO, they would get 84% of them. This disparity drives Entergy's overturning of CRA's verdict, but Entergy has no explanation for the disparity. The

[47] Response to data requests Staff 18-60 and Staff 18-24.

[48] See pdf entitled "RTO analysis for Entergy Operating Companies, May 2011" at page 5. Found at http://entergy-arkansas.com/transition_plan/.

Arkansas Attorney General asked this question in a data request and Entergy provided the following answer:

> "Subtracting the Entergy Operating Companies' results from the CRA results for the Entergy Region indicates that the adjusted production costs of other entities within the Entergy Region (i.e. IPPs and other load-serving entities) fall by more under the Join SPP case than the Join MISO case. The Entergy Operating Companies do not have sufficient information from CRA to describe why the adjusted production costs of other entities within the Entergy Region fall by more under the Join SPP case than the Join MISO case."[49]

Q. Was this "adjustment" proper?

A. No. Certainly not without a detailed, convincing answer to the Attorney General's question. But, even putting this question aside, the "adjustment" is not proper because the OAA simply ignores benefits that accrue to other parties. Since these other entities are presumably tax-paying, job-sustaining or job-creating businesses, and ratepayers in Arkansas or the other States, I think the Arkansas Commission would want to take these Trade Benefits into account when it rules on which RTO to join.

E. Entergy changed the starting point for benefit estimates and, without adequate explanation or justification, Entergy claims that increases MISO's advantage over SPP.

Q. What is the third "adjustment" Entergy made to the CRA Analysis?

A. Entergy changed the "base case" used by CRA from one in which all the Entergy Operating Companies were dispatched together to one in which the EAI region was separate from the rest of Entergy.

[49] Response to AG 13-6.

Q. What is the result of this “adjustment?”

A. This “adjustment” increases both the benefits of joining SPP (from $589 million to $747 million) and the benefits of joining MISO (from $619 million to $817 million).[50] These represent Entergy’s final calculation of Trade Benefits and are highlighted in their Report. This “adjustment” increases MISO’s Trade Benefit advantage over SPP from $30 million to $70 million.

Q. What is your opinion of this “adjustment?”

A. I have two objections to this “adjustment.”

Q. What is the first objection?

A. My first objection is that it does not make any conceptual sense that a change in the base case should increase the relative advantage of one alternative case over another. As an example, let’s say we have three potential choices to buy something, each costing us a certain amount of money. Choice A (our “base case”) costs $100, choice B costs $60 and choice C costs $45. As compared to Choice A, choice B is $40 cheaper and choice C is $55 cheaper. Note, too, that Choice C is $15 cheaper than Choice B. Given this, the lowest cost alternative is Choice C.

If I change the cost of the base case (Choice A) to $200, all I have done is increase the difference between the base case and the two alternatives (B and C) by $100. Choice B is now $140 cheaper than Choice A and Choice C is now $155 cheaper. However, Choice

[50] See PDF entitled “RTO Analysis for Entergy Operating Companies, May 2011,” at page 6.

C is still $15 cheaper than Choice B. In other words, the relative difference between these two “alternate” choices has not changed due to a change in the Base Case. To put it another, simpler way, if we want to see who is taller, you or me, the difference in height would be the same whether we are both standing on the ground or both standing on top of a desk.

Q. What is your second objection?

A. My second objection is that using a base case where EAI is separate from the rest of Entergy may be confusing the benefits of joining SPP or MISO with the benefits of the Entergy Operating Companies operating in a combined manner. While there is nothing wrong with EAI operating as a stand-alone entity, we should be trying here to measure the benefits of joining SPP or MISO, not the benefits of the combined dispatch for the Entergy Operating Companies. To go back to the above analogy, if we want to find out who’s taller, it’s ok if we both stand on a table. The same comparison would be a bad idea, however, if we want to record our actual heights.

Q. Does this “adjustment” indicate benefits to combined dispatch?

A. Yes, although it’s important to stress that there may be other costs that are not accounted for here. The change in the base case increases the Trade Benefits of joining either SPP or MISO by $158 million and $198 million, respectively. Again, this is a relatively large increase. Recall that CRA’s study showed Net Benefits before allocation of transmission costs to the Entergy region of $661 million and $529 million, respectively.

F. Entergy adds estimates of Other Benefits that were not quantified in the CRA Study including those from reduced requirements for contingency reserves, planning reserves, and regulation service. The credibility of all of these estimates is undermined because of Entergy's admitted failure to consider deliverability and because of oversimplified analytic methods.

Q. What was Entergy's fourth "adjustment" to the latest CRA results?

A. Entergy's fourth "adjustment" was to add estimates of benefits that were not quantified in the CRA Study. Entergy chose to quantitatively estimate the cost savings from possible reductions in: (a) contingency reserves; (b) planning reserves; and (c) regulation service.

Q. What was the dollar value of these three added benefits?

A. Entergy estimates that, on a present value basis for the period from 2013 to 2022, these additional benefits would be $770 million if it joined MISO and $646 million if it joined SPP.[51] These are big numbers with big consequences in the context of a cost benefit study. With this one "adjustment," Entergy adds another $124 million to MISO's alleged benefit advantage over SPP – this is $770 million minus $646 million. Just to put this in perspective, recall that the latest CRA Study found that Net Benefits for joining SPP (before any allocation of transmission costs) were higher by $132 million, so this fourth "adjustment" just about wipes out SPP's CRA-estimated advantage.

Q. Do you have concerns with these Entergy estimates?

A. Yes.

[51] Entergy Evaluation Report at page TA-23.

Q. Do you agree that in concept there could be such benefits from joining an RTO or ISO?

A. Yes. In concept, such benefits could be achieved.

Q. Do you agree with Entergy's estimates of these benefits for MISO and SPP?

A. No. The primary reason that I do not find Entergy's actual estimates to be credible is that Entergy expressly states that, in estimating these additional production cost benefits, it did not account for deliverability. In its response to a data request, EAI states that "The Entergy Operating Companies made no conclusion regarding the location of the resources that provide planning, contingency or regulation reserves in the Join MISO case."[52] In that same response, in talking about the Join MISO case, EAI states that "there was no implicit assumption of deliverability of capacity resources from MISO North."[53]

Q. Is a demonstration of deliverability required?

A. Yes. For example, NERC Standard TOP-002-2.R7 states: "Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency."[54]

Q. Has the FERC addressed this topic in cases involving MISO?

A. Yes. In May 2008, MISO filed at the FERC requesting a reduction in its minimum contingency reserve amount from 2,250 MW to 1,500 MW.[55] The FERC rejected

[52] Response of Entergy Arkansas to Third Set of Data Requests of Arkansas Electric Cooperating Corporation, Question No. AECC 3-5, filed June 15, 2011.
[53] Ibid.
[54] See NERC Reliability Standard TOP-002-2 – Normal Operations Planning.

MISO's proposal because it failed deliverability tests.[56] In a July 16, 2009 Order,[57] the FERC summarized its finding:

> "The Commission found that for winter and summer periods, the deliverability tests under the proposed minimum contingency reserve of 1,500 MW failed due to transmission constraints. Consequently, the reserves that MISO planned to deploy…would be unable to reach parts of the system under certain contingencies. In addition, the Commission noted that the base case provided by the MISO already contained transmission limit violations, which further called into question the deliverability of the 1,500 MW. Thus, the Commission found that the MISO's proposal to reduce its reserve amount to 1,500 MW failed to satisfy the deliverability requirements of…NERC reliability standard TOP-002, R7."[58]

Q. Let's discuss each of the three additional classes of benefits in turn. What are Entergy's estimates of the benefit from reduced contingency reserves?

A. Entergy estimated that the benefit of reduced contingency reserves would be $106 million if it joined MISO and $87 million if it joined SPP.[59]

Q. How does Entergy describe the source of these benefits?

A. Entergy states: "Because of the scale and market design of an RTO with a functioning Day 2 Market, the amount of contingency reserves required to serve an RTO and the Entergy Operating Companies collectively is less than the amount of contingency

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[55] *Midwest Independent Transmission System Operator, Inc.*, 128 FERC ¶ 61,052.
[56] *Midwest Independent Transmission System Operator, Inc.*, 125 FERC ¶ 61,323 (2008) (FERC December 2008 Order) at paragraph 31.
[57] *Midwest Independent Transmission System Operator, Inc.*, 128 FERC ¶ 61,052.
[58] Ibid. at paragraph 5.
[59] Entergy Evaluation Report at page TA-23.

reserves required to serve them separately. This is because contingency reserves can be 'shared' among participants in an RTO…"[60]

Q. Do you agree?

A. In concept, there could be such benefits. My concern is with the method Entergy uses to actually estimate the dollar value. Again, for all three classes of additional benefits my primary concern is that Entergy failed to account for deliverability in its analysis.

Q. Beyond this primary concern, do you have concerns specific to the estimated benefit for contingency reserves?

A. Yes.

Q. How are the amounts of contingency reserves set?

A. As background, note that NERC Standard BAL-002 requires each RTO to carry enough contingency reserve to meet the single largest contingency on its system[61] – for example, this could be the loss of the largest power plant on the system.

Q. Do SPP and MISO comply with this requirement?

A. Yes. As I understand it, both SPP and MISO carry an amount of contingency reserve that is greater than this NERC minimum requirement.[62]

[60] Ibid. at page TA-25.

[61] NERC Reliability Standard BAL-002-0 – Disturbance Control Performance at Section B.R3.1.

[62] The SPP Reserve Sharing Group carries enough daily contingency reserve to equal the generating capacity of the largest unit scheduled to be on-line plus one-half of the capacity of the next largest generating unit scheduled to be on-line. See Section 6.3 of the Southwest Power Pool Criteria. As of 2008, MISO procured an amount in excess of its single largest contingency. See FERC December 2008 Order at paragraph 5. It appears that MISO continues to procure contingency reserve in excess of the minimum requirement. See page 2 of 2 of the SPP Consolidated

Q. What is the amount required for each?

A. According to Entergy, SPP will have a contingency reserve requirement of 1,876 MW and MISO will have a requirement of 2,042 MW.[63]

Q. Do you have a concern with this – again, beyond the deliverability issue?

A. Not in terms of the strict letter of the law, but I do want to draw attention to just how close the two figures are and to put this in the context of the large difference in the peak loads of SPP and MISO. SPP's peak load, with Entergy included, would be about [redacted] MW[64] while MISO's, with Entergy included, and would be about [redacted] MW.[65] This means that SPP and MISO will have just about the same number of megawatts of contingency reserve, but MISO will be protecting a load level that is almost twice the peak load level of SPP. My point is that, even though the amount of reserves is about the same, surely it is reasonable to conclude that MISO is less well protected than SPP.

To see the common sense in this concern, think about comparing the number of firehouses in two towns. Say a town with a population of [redacted] people has ten fire houses to respond to house fires in the town. Then another town with [redacted] people

Balancing Authority Steering Committee Meeting Minutes from March 1, 2010, found here: http://www.spp.org/publications/CBASC%20Minutes%2003_01_10.pdf.

[63] Entergy Evaluation Report at page TA-26.

[64] According to Entergy, SPP's 2010 peak load was approximately 45,000 MW. See Entergy Evaluation Report at page 79. Entergy's 2010 peak load was approximately [redacted] MW. See Entergy Confidential Work Paper *HSPM_Contingency_Benefit*.xls.

[65] According to Entergy, MISO 2010 peak load was approximately 116,000 MW. See Entergy Evaluation Report at page 79.

has the same number – ten firehouses. Would we conclude the fire protection is equal in the two towns? No.

My concern is that, while Entergy takes the time to calculate a $19 million advantage for MISO related to contingency reserves, it assigns no benefits to the fact that, looking only at contingency reserves, SPP provides better protection and lower risk than MISO.

Q. Is your concern that contingency reserve is not related to load?

A. Yes. Again, that is not required by the letter of the law, but I think it is a point worth making when comparing benefits of joining MISO or SPP and to counter Entergy's repeated scale argument – that is, Entergy's argument that MISO is better because it is bigger.

Q. Does Entergy ever calculate contingency reserve as a percentage of peak load?

A. Yes. In its Evaluation Report, Entergy notes that the amount of contingency reserve for the Entergy system – absent membership in an RTO or ISO – was "assumed to equal 4.35% of the monthly coincident peak demand of the balancing area."[66]

Q. Do you have any other concerns with Entergy's estimate of the benefit from reduced contingency reserves?

A. Yes. My concern relates to the current dispute at the FERC on the SPP-MISO Joint Operating Agreement (JOA). Entergy concludes that an unfavorable result in that dispute

[66] Entergy Evaluation Report at page TA-26.

– that is, a ruling against MISO – could reduce benefits in the Join MISO case by $11-$30 million.[67]

Q. Did Entergy give any more details?

A. Yes. Entergy notes that a 10% increase in both prices for contingency reserves and the quantity of contingency carried reduces Entergy's benefits from joining MISO by $11 million. Entergy notes that a 25% increase in both prices for contingency reserves and the quantity of contingency reserves carried reduces Entergy's benefits in joining MISO by $30 million.[68]

A recent FERC decision ruled on legal terminology, but not on compensation by MISO for use of SPP transmission facilities. Without a resolution on compensation, the prices for contingency reserves cannot be known with precision.

Q. Do you have any other concerns related to contingency reserve benefits?

A. I have one final concern. As an estimate of the price of reserves in both MISO and SPP, Entergy uses the 2010 average monthly costs to load of MISO's contingency reserves.[69] While this may be a convenient source, Entergy did not provide evidence that this price is necessarily indicative of expected future prices in MISO or in SPP.

Q. Let's turn to planning reserves. What are Entergy's estimates of additional benefits?

[67] Response of Entergy Arkansas to Eighteenth Set of Data Requests of Arkansas Public Service Commission Staff, Question No. STAFF 18-36, filed June 6, 2011.
[68] Ibid.
[69] Ibid.

A. Entergy estimates that the present value of its cost savings, over the period from 2013 to 2022, from reducing the level of planning reserves required would be $303 million in savings in SPP and $397 million in MISO.[70] Note that this estimate reflects substantial reductions. For the case in which Entergy would join MISO, Entergy's estimate is that the amount of required planning reserve would drop from 16.85%[71] to 12%.[72] For the case in which Entergy would join SPP, Entergy estimates the planning reserve would drop to 13.64%.

Q. Do you agree with these estimates?

A. No. Again, my primary concern is that Entergy did not demonstrate the deliverability of these reserves.

Q. Beyond your primary concern with deliverability, do you have other concerns?

A. Yes. Beyond my concern with deliverability, I am concerned because Entergy failed to address an obvious question, which is: does the lower planning reserve requirement in MISO also mean that ratepayers have a lower level of reliability protection? And, if so, how can you call it a benefit as compared to SPP's higher level of protection? I raise this question because Entergy determined the planning reserve requirements differently for SPP and MISO.

Q. Let's turn to the third and final source of additional benefits. What is the benefit estimated for reduction in regulation service?

[70] Entergy Evaluation Report at page TA-23.
[71] Ibid. at page TA-27.
[72] Ibid. at page TA-27 through TA-28.

A. Entergy estimates $256 million in savings for reduction in regulation service in SPP and $267 million in savings for that reduction in MISO.[73]

Q. How did Entergy come up with the regulation requirement estimate for SPP?

A. [redacted]

Q. Is this a credible analysis?

A. No. The estimate is based on an oversimplified analysis – especially in light of the fact that $256 million of benefit is very large in the scheme of the overall cost benefit analysis. I say it is oversimplified, obviously, because it is based on only two data points. However, even putting the number of data points aside, it is oversimplified because it presumes that the right level of regulation service is dictated by a single factor – the level of load. At least three other true drivers of regulation requirements are the nature and extent of load fluctuations, the type of generation available, and, especially with intermittent resources, the nature and extent of generator performance.

Q. Any other concerns?

A. Yes, one more. Entergy's use of average monthly costs of regulation to load in MISO for 2010[74] as its price estimate for regulation is not necessarily indicative of expected future prices in MISO and SPP.

[73] Entergy Evaluation Report at page TA-23.

G. Entergy's "adjustment" to CRA's Transmission Cost Allocation fails to consider (a) the possibility of increased Trade Benefits, (b) the cost of MISO's "comparability" standard, and (c) the rules for allocation under SPP's Unintended Consequences provision.

Q. What is the fifth "adjustment" Entergy made to the CRA net benefit analysis?

A. The fifth "adjustment" Entergy made to CRA's analysis was to the Transmission Cost Allocation.

Q. How did CRA determine the Transmission Cost Allocation?

A. CRA used Transmission Cost Allocation estimates provided by SPP and MISO. These were estimates of the net allocation based on the approved allocation methods used in SPP and MISO. By "net" I mean to reflect the fact that some costs may be allocated to Entergy from the RTO or ISO. Since these would be imposed on Entergy ratepayers, I will refer to them as a negative allocation. And some costs might be allocated to the RTO's or ISO's existing members from Entergy – this would represent a reduction in costs for Entergy ratepayers or a positive allocation. The netting then allows the negative allocation to be offset by the positive allocation in part or in full.

Q. What were the net Transmission Cost Allocation estimates used by CRA in its studies?

[74] Response of Entergy Arkansas to Twelfth Set of Data Requests of Attorney General's Office, Question No. AG 12-11, filed June 8, 2011.

A. The net Transmission Cost Allocation of joining SPP was estimated to be between a negative $937 million and a positive of $23 million.[75] A range was given because CRA did not know which projects in SPP's expansion plan (e.g., projects built before integration versus projects built after integration) would be allocated to Entergy. The estimate for MISO, on the other hand, was a single number of negative $782 million.[76]

Q. Why did Entergy "adjust" the transmission cost estimates used in the CRA studies?

A. Entergy adjusted the CRA transmission cost numbers because it received proposals from both SPP and MISO that more clearly discussed which planned transmission projects would be allocated to Entergy.

Q. What were the new Transmission Cost Allocation estimates used by Entergy in its Evaluation Report?

A. For SPP, Entergy's estimate of the Transmission Cost Allocation was between a net negative $209 million and a net positive $59 million.[77] For MISO, Entergy's estimate was between a net negative $327 million and zero.[78]

Q. Did Entergy provide any additional thoughts on these ranges?

A. Yes. Entergy stated that it believed it was more likely that the actual transmission cost allocation for joining MISO would be closer to the low end of the MISO range – zero

[75] Entergy Evaluation Report at page TA-35.
[76] Ibid.
[77] Ibid. at page 13.
[78] Ibid.

dollars – while the cost of joining SPP would more likely be at the high end of the SPP range – closer to a cost of $209 million.

Q. Do you believe this claim was adequately supported?

A. No. I have three reasons for concluding that Entergy's estimates, and its polar opposite assessment of risk for SPP and MISO, are not adequately supported: (a) Entergy allocated costs for new transmission investment in SPP without adding in the possible, offsetting Trade Benefits from this investment; (b) Entergy failed to allocate to itself transmission costs for the investments necessary to meet the "comparability" standard in MISO's offer; and (c) Entergy allocated transmission costs to itself through SPP's Unintended Consequences process without the requisite showing that Entergy would benefit from the transmission investment.

Q. Let's discuss each of these three in turn. Please explain the first reason you do not find Entergy's Transmission Cost Allocation to be adequately supported.

A. As background, note that Entergy speculates that, going forward, a portion of new 300-kV or higher voltage projects that have not yet been identified in SPP will be allocated to Entergy under the Highway/Byway methodology. Specifically Entergy states:

> "Although SPP's proposal focuses on the fact that the Operating Companies would not be responsible for the costs of projects that have already been built or planned, such as the Balanced Portfolio projects, the fact remains that the Operating Companies will automatically pick up a load ratio share of all future projects of 300 kV voltage or higher that come out of the SPP planning process and that have not been identified as of April 2011."[79]

[79] Ibid. at page 22.

My problem is that, while it readily speculates about the costs of these unidentified transmission investments, Entergy does not consider the potential Trade Benefits from these projects. These unidentified, new projects were not included in CRA's analysis, and, therefore, the Trade Benefits associated with them have not been forecast by CRA. If Entergy wants to speculate, it should speculate about both the costs and the possible, offsetting benefits.

Q. Please explain the second reason you do not find Entergy's estimate to be adequately supported.

A. My second reason is that Entergy ignores the fact that it may have to make significant transmission investments to comply with the "system comparability" standard set in MISO's offer.[80] MISO's transmission cost allocation proposal envisions creating two planning regions: MISO North – the current MISO footprint – and MISO South – covering the Entergy and Cleco areas. Both areas would be a part of MISO's transmission expansion plan studies, but the transmission costs in each area would not be shared with the other area for a "transitional period." This transitional period would last at least five years and would not end until "system comparability" is achieved.[81]

Q. How is "system comparability" defined?

A. To achieve MISO's system comparability standard, two conditions must be met: (a) comparable transmission congestion levels must exist in the MISO North and MISO South Regions and (b) additional MVP projects must be identified for the Entergy region

[80] Ibid. at page 66.
[81] Ibid.

through the MISO planning process, such that in aggregate the MVPs create benefits that are spread across the combined MISO footprint and are roughly commensurate with costs incurred. If comparability is not achieved within ten years, the issue will be "revisited."[82]

Entergy notes specifically that it will not have to share in the costs of MVP projects because of the MISO North and MISO South designations. However, it fails to note that one of the primary reasons MISO made its MISO North and MISO South proposal was because it was worried about having to subsidize MISO South as it built new network upgrades to achieve "comparability."

Q. What did MISO specifically say in this context?

A. The first sentence of MISO's transmission cost proposal to Entergy states:

> "Due to the absence of historical seams agreements for transmission planning between MISO and Entergy, potential integration of Entergy into the MISO presents unique concerns with respect to transmission planning, and as such a risk that costs will not be shared equitably."[83]

Further, in a filing to the FERC asking for approval of its transitional period for Entergy, MISO states:

> "Due to the absence of any seams agreement between them, MISO and Entergy have not had any historical opportunity to study the levels, and to address the interaction of, congestion and related factors in their respective areas. If their systems are not comparable in those respects, and such non-comparability is not addressed, the Northern Planning Region may end up subsidizing Network Upgrade costs in the Southern Planning Region. Accordingly, MISO needs to study Entergy's congestion and other pertinent characteristics, and work towards achieving comparability in infrastructure levels, before fully applying regional cost allocation rules to

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[82] Ibid. at page 67.

[83] See MISO's April 15, 2011 Proposal to Entergy at page 1, filed as Exhibit 15 in Entergy's Proposal.

> Network Upgrades located and terminating solely in either the Southern Planning Region or the Northern Planning Region."[84]

MISO also states in this same filing that:

> "Given the potential for disparity in the level of transmission infrastructures and distribution of benefits between the Northern Planning Region and the Southern Planning Region, it is reasonable to establish a transition period during which the cost of any infrastructure build-up in the Southern Planning Region aimed at achieving comparability with the Northern Planning Region should not be shared by the latter. Nor should the costs of currently planned infrastructure in the Northern Planning Region be shared with the Southern Planning Region until benefits can be demonstrated."[85]

Q. What is the point you draw from these quotes by MISO?

A. The point is that MISO sees a clear risk that Entergy will have to spend significant sums of money on new network upgrades, which have yet to be identified, to achieve "comparability." This is why MISO created a separate area – MISO South – to protect its existing Members from having to pay for these "comparability" upgrades. None of these costs would be shared with the rest of MISO, but instead would be borne completely by Entergy ratepayers. And, yet, Entergy fails to include any estimate for "comparability" upgrades when it estimates the Transmission Cost Allocation with joining MISO.

Q. What is the third and final reason you believe the Entergy Transmission Cost Allocation is not adequately supported?

A. My third reason is that, while Entergy did not speculate about any cost of the "comparability upgrades," it did speculate about costs to be allocated by SPP under its Unintended Consequence provision and Entergy failed to support its estimates of such an

[84] See MISO's June 3, 2011 Filing in Docket No. ER11-3728-000 at page 4.
[85] Ibid. at page 5.

allocation. To see this, recall that the only reason Entergy would be allocated some costs as a result of this Unintended Consequences study would be if Entergy were shown to have received benefits from the Priority Projects. To support its assertion that it would face an allocation from the Unintended Consequences provision, Entergy would have to analyze the benefits, but Entergy provided no such analysis, so its assertion is unsupported. And, if Entergy had identified such benefits to support an allocation, Entergy would have to take the next step which is to assure those benefits had been reflected in the estimated benefits of joining the SPP RTO. Entergy did none of these things so its allocation of cost from the Priority Projects through the Unintended Consequences provision is not credible.

IV. THE ARKANSAS COMMISSION SHOULD ALSO CONSIDER FIVE STRATEGIC ADVANTAGES WHICH CLEARLY MAKE JOINING SPP A BETTER CHOICE THAN JOINING MISO

A. Because of the well-defined and well-respected role of the SPP Regional State Committee (RSC), the Arkansas Commission will have a much better opportunity to act on behalf of Arkansas ratepayers in the SPP RTO than in MISO.

Q. What is the first strategic advantage of joining the SPP RTO?

A. The first strategic advantage is that the Arkansas Commission (and other Entergy State Commissions) will have a much better opportunity to protect its ratepayers through active participation in the SPP RTO than in MISO.

Q. Through what forum can the Arkansas Commission and other retail regulators participate in the SPP RTO or MISO?

A. In SPP, the Arkansas Commission and the Commissions from other Entergy states will have the option to actively participate through the SPP RSC, an official Organizational Group within SPP made up of retail regulatory commissioners. In MISO, retail regulators participate through an external group called the Organization of MISO States (OMS).

Q. Has Entergy stated an opinion as to which RTO allows for more effective participation by retail regulators?

A. Yes. Entergy does not seem to believe that either RTO provides a better or worse opportunity for the Commissions to act on behalf of ratepayers. Specifically, Entergy states:

> "Whether in the SPP RSC or in the MISO OMS, the Operating Companies' regulators would have a forum in which to provide their views regarding transmission issues. Although the Retail Regulators would, in either SPP or MISO, no longer possess exactly the same authority as they currently have under the recent modifications to the ICT, they would nonetheless have a means of direct input to the RTO Board of Directors on such issues and would maintain the opportunity to influence decisions on these matters."[86]

Q. Do you agree with Entergy on this point?

A. No. SPP clearly provides a better opportunity for retail regulators to act on behalf on their ratepayers. The SPP RSC Bylaws lay out explicit responsibilities and grant decision-making authority to the RSC, specifically related to determination of transmission cost allocation and resource adequacy policies. The Bylaws state that the RSC's purpose is as follows:

> "The SPP RSC shall provide collective state regulatory agency input and participation in the Southwest Power Pool, Inc. ("SPP") and SPP's Board of Directors, committees, working groups and task forces, including any independent transmission system operator ("ISO") or regional transmission organization ("RTO") formed by the SPP. Such input and participation shall include but not be limited to: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage stamp rates will be used for the regional access charge; determination of Financial Transmission Rights ("FTR") allocations where a locational price methodology is used; determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights; determination of the approach for resource adequacy across the entire region; determination of whether transmission upgrades for remote resources will be included in the regional transmission planning process; and determination of the

[86] Entergy Evaluation Report at pages 43-44.

> role of transmission owners in proposing transmission upgrades in the regional planning process."[87]

Q. Please discuss some specific examples that show how the SPP RSC has actively participated in SPP issues?

A. I will give four examples.

First, the RSC oversees two official SPP groups, namely the Cost Allocation Working Group (CAWG) and the Rate Impacts Task Force, that deal directly with SPP issues. For example, the RSC and the CAWG were key decision makers in developing and approving the existing Highway-Byway transmission cost allocation methodology.

In addition to the RSC's involvement in developing the Highway/Byway Cost Allocation methodology, the RSC is heavily involved in the Unintended Consequences Review of the impacts of cost allocation. The RSC and MOPC have formed the Regional Allocation Review Task Force (RARTF) to develop "the analytical methods to be used" to "review the reasonableness of the regional allocation methodology and factors . . . and the zonal allocation methodology." The RARTF reports directly to the RSC and MOPC for approval of the review of cost allocation impacts and any changes to the cost allocation methodology.

Second, the RSC has been involved with the development of SPP's current and future markets.

[87] Southwest Power Pool, *Regional State Committee Bylaws*, April 27, 2009 at page 2.

Third, the RSC typically has its quarterly meeting on the day preceding the SPP Board of Director's meeting and, then, the RSC actively participates in the Board meetings. In fact, the RSC gives a report at each of these Board meetings.

Fourth, the RSC is the only state regulatory organization that can direct its RTO to make FERC Section 205 filings. The OMS does not have this authority.

Q. Does the OMS provide comparable responsibilities and input opportunities?

A. No. The OMS does not have any formal responsibilities or voting rights before the Board of Directors. For example, MISO drafted its transmission cost allocation proposal internally and OMS had no authority to make decisions during the process other than to submit comments and recommendations. The MISO OMS does have three seats on MISO's Advisory Committee.

Note that Carl Monroe, SPP's Executive Vice President and Chief Operating Officer, provides more detail in his Testimony on the regulatory advantages of the SPP RSC over the MISO OMS, and he also discusses other SPP governance benefits.

B. To realize the estimated benefits of joining an RTO or ISO, there must be strong transmission links between Entergy and the RTO or ISO. SPP has multiple transmission links to Entergy and they are stronger than Entergy's single-path link to MISO. Also, three, significant transactional disputes have created considerable uncertainty for the MISO-Entergy link.

Q. What is the second strategic advantage for Entergy joining the SPP RTO?

A. The second strategic advantage is that SPP's multiple-path transmission link to and from Entergy is stronger than the single-path MISO-Entergy link; and, further, the strength of the MISO-Entergy link is undermined by these transactional disputes.

Q. Why is the strength of the transmission link important to Arkansas ratepayers and ratepayers in the other Entergy States?

A. It is fundamentally important because, to realize the estimated benefits of joining an RTO or ISO – whatever they are in dollar value – there must be strong transmission links to and from Entergy and the RTO or ISO.

Q. Why do you claim SPP's link is stronger?

A. I believe the SPP-Entergy links are stronger physically because they are more diverse – there are multiple paths – and the stated capacity is larger. Also, SPP's links are stronger because three, significant transactional disputes have created considerable uncertainty for the MISO-Entergy transmission link.

Q. How does Entergy describe its physical transmission links to SPP?

A. Entergy describes its physical ties to SPP in two ways. First, it discusses its "ties" to SPP through nine interconnections with SPP market members. In a data response, Entergy lists a total of nine interconnections between: (a) AEP-West and Entergy Texas, (b) AEP West and Entergy Arkansas, (c) AEP West and Entergy Louisiana, (d) Empire District and Entergy Arkansas, and (e) Oklahoma Gas and Electric and Entergy Arkansas.[88] These nine have a total capacity of 4,302 MVA.[89]

Secondly, Entergy discusses "45 interconnections" and adds to these nine additional ties to Cleco, Southwest Power Administration, and the City of Lafayette. These 45 have a total capacity listed of over 14,000 MVA.[90]

Q. How does Entergy describe its links to MISO?

A. When asked about its "interconnections" with MISO, Entergy speaks of an "active transmission line capacity" of "2,089 MVA," but notes that the "interface is limited . . . to 1,500 MVA."[91] This is a single-path link involving Ameren, AECI, and Entergy Arkansas.

Q. What is your sense after reading Entergy's descriptions?

[88] Response of EAI to AG 12-3.
[89] Ibid.
[90] Response to Staff 23-1.
[91] Response to Staff 23-4.

A. Even this brief description by Entergy gives the sense that the SPP-Entergy links together offer a more diverse, larger, and, therefore, stronger transmission path. Still, it is not meant to be a full apples-to-apples comparison.

Q. What are the three transactional disputes you mentioned?

A. The three transactional disputes, in turn, involve: (a) AECI's notice to terminate the Interchange Agreement, which governs the only physical link Entergy points to between Entergy and MISO; (b) the possibility that Ameren may leave the MISO – this is Entergy's only physical link to a MISO Member; and (c) the dispute over the SPP-MISO Joint Operating Agreement (JOA).

Q. Let's briefly discuss each of the three disputes. What is the relevant concern about the dispute over the Interchange Agreement?

A. To start, note that AECI has provided notice that it will terminate the Interchange Agreement as of June 2013.[92] Entergy claims the parties have agreed to extend the Agreement for 20 years "in principle,"[93] while MISO has said only that the parties are in negotiations.[94] However, the fact remains that the Agreement has not been extended and it needs to be extended before we can know the terms going forward. Without knowing the terms going forward, we are uncertain whether Entergy would realize the estimated reliability and cost benefits of joining MISO.

Q. What is your concern about the possibility of Ameren leaving MISO?

[92] Entergy Evaluation Report at page 76.
[93] Ibid.
[94] See MISO's April 8, 2011 Filing in Docket No. EL11-34-000 at page 8, note 27.

A. Entergy interconnects with MISO through Ameren, a current MISO member. If Ameren was not in MISO, Entergy would not be interconnected with MISO at all and that would make it more complicated for Entergy to join MISO. To make Entergy a member, MISO would have to rely on an obscure provision that, subject to review and decision by the MISO Board, waives the physical interconnection requirement if MISO can expect to enjoy benefits from allowing such an entity into MISO.[95] Again, the concern is that the dispute creates uncertainty. Until we know whether Ameren is going to remain a MISO Member, it is uncertain whether the reliability and cost benefits of joining MISO can actually be realized.

Q. What is the latest on Ameren's deliberation on whether to stay in MISO?

A. The Missouri Commission has required Ameren's Missouri operating company to conduct cost benefit analyses to determine if remaining in MISO is in the best interest of the ratepayers. The latest is that the Cost Benefit Study found a $70 million benefit to remaining with MISO through 2013.[96] However, the Cost Benefit Study noted numerous uncertainties related to participation in MISO markets, all of which Ameren Missouri considers "material;" this led to the view that only a temporary, 20-month extension of Ameren's participation in MISO is warranted.[97]

Q. What are the uncertainties raised in the Cost Benefit Study?

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[95] MISO Transmission Owner Agreement, Section V.A.2 at PDF page 31.
[96] See Ameren Missouri's November 1, 2010 Filing at the Missouri Public Service Commission in Case No. EO-2011-0128 at page 6.
[97] Ibid. at page 8.

A. The uncertainties for Ameren's decision on whether to stay in MISO echo some of the same uncertainties that can be raised about Entergy joining MISO. The uncertainties include: (a) proposed changes to the MISO Transmission Expansion Plan, including the issue of Multi-Value Project cost allocation; (b) efforts to redesign the MISO's Revenue Sufficiency Guarantee and Revenue Neutrality Uplift payments process; (c) issues surrounding the availability of transmission to make off-system sales in the MISO's markets or in other RTO markets; (d) the amount of the exit fee for leaving MISO, which may change; (e) MISO's potential capacity market; and (f) the exit of two large MISO Members – FirstEnergy and Duke.

Even if Ameren stays in MISO, it may only be on an interim basis. Ameren Missouri asked the State Commission to approve its continued membership until 2013, when they would again reassess the costs and benefits of staying in MISO.

Q. What is the nature of the dispute over the SPP/MISO JOA and what are your concerns with it?

A. MISO filed a petition for a declaratory order at the FERC asking the FERC to interpret a particular section of the JOA to allow MISO to flow additional energy on SPP's system to integrate Entergy into MISO. SPP disputed MISO's interpretation of the relevant section of the JOA, and asked the FERC to require the parties to renegotiate the JOA and allow SPP to recover costs from MISO for additional parallel flows on its system and transmission upgrade costs associated with MISO's use of SPP's grid.

My concern is the same with the other two disputes – unless and until the JOA dispute is resolved, it is uncertain whether the estimated benefits of joining MISO or SPP can be realized. For example, Entergy itself notes the uncertainty when it acknowledges that a ruling adverse to MISO in the case would have a negative impact on the contingency reserve benefits calculated for joining MISO; reduction in these benefits is estimated to be $11 million to $30 million.[98] And the actual costs for Entergy to join MISO would not be known either – depending on the FERC ruling, MISO and Entergy may be required to compensate SPP for use of its system.

I will note, too, that parallel flows are at the heart of the JOA dispute. SPP estimates that just 8% of all flows for transactions between MISO and Entergy will actually flow over the MISO-Entergy interconnection. The rest will end up in other systems: 30% in SPP, 42% in TVA, and 17% in AECI.[99] The dispute over parallel flows could go on into the future and involve other parties beyond SPP.

Q. Has FERC addressed this dispute?

A. Yes, in part. Very recently, on July 1, 2011, FERC issued an Order on the interpretation of a legal term. Based on that alone, the FERC concluded that the existing JOA "would allow for the sharing of available transmission capacity between MISO and Entergy Arkansas and SPP and Entergy Arkansas in the event that Entergy Arkansas becomes a transmission-owning member of MISO."[100]

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[98] Response of Entergy Arkansas to Eighteenth Set of Data Requests of Arkansas Public Service Commission Staff, Question No. STAFF 18-36, filed June 6, 2011.

[99] See SPP's May 9, 2011 Comments in Docket No. EL11-34-000 at page 2, note 1.

[100] 136 FERC ¶ 61,010 at paragraph 60.

However, the FERC Order also anticipates that the JOA will be re-negotiated in good faith by MISO and SPP. Specifically, the FERC states:

> "While we find that section 5.2 permits SPP and MISO's shared use of available transmission capacity with Entergy Arkansas, we also recognize SPP's statement that the SPP JOA should be renegotiated . . . MISO and SPP have an obligation to negotiate in good faith in response to revisions (including deleting, adding, or revising requirements or protocols) either MISO or SPP may propose."[101]

In addition, the FERC Order anticipates a full hearing on alleged impacts. The FERC stated: "To the extent commenters are concerned with any potential impacts of Entergy Arkansas joining MISO, we anticipate that these issues would be raised and addressed in the filings required to implement any decision by Entergy Arkansas to join MISO as a transmission-owning member."[102]

The point is that rules for and cost of Entergy's use of SPP's links to MISO are not resolved so uncertainty on benefits remains.

C. With the recent FERC decision against the New Jersey Board of Public Utilities, the Arkansas Commission should be concerned with being at odds with the FERC on capacity additions if MISO establishes a capacity market as planned. SPP has no plans for such a market.

Q. What is the third strategic advantage of joining the SPP RTO?

[101] Ibid. at paragraph 64.
[102] Ibid. at paragraph 67.

A. The third strategic advantage of joining the SPP RTO is that SPP has no plans for a capacity market while MISO does – this is given importance by a recent FERC ruling.

Q. What is the current status of MISO's planned capacity market?

A. MISO is in the early stages of developing a capacity market which Entergy admits is "sometimes described as mandatory."[103] MISO has discussed some details of the market, but the full proposal will not be available until MISO makes a resource adequacy filing on July 15th of this year.

Q. What has been the recent experience with RTO Capacity Markets?

A. Such markets have recently resulted in conflicts between State and Federal authorities over resource adequacy. The most striking example of this occurred recently in New Jersey.

Q. What happened in New Jersey?

A. Due to concerns over a lack of in-State resources being built, New Jersey conducted a competitive procurement for new combined cycle plants; it was called the Long-Term Capacity Agreement Pilot Program (LCAPP). It provided capacity price guarantees to this new in-State generation.

Q. Have other states who use PJM's capacity market expressed concerns over resource adequacy?

[103] Entergy Evaluation Report at page 88.

A. Yes, earlier this year the Maryland Commission issued a draft Request For Proposals for new generating capacity to serve the State, citing the fact that "market forces have not produced new generation in our region."[104] The Maryland Commission will make a determination in the coming months as to whether to issue a final RFP.

Q. Was it New Jersey's actions that brought about the FERC proceeding you noted above?

A. Yes. Parties within PJM, and PJM itself, saw LCAPP as a market-distorting subsidy and moved to tighten the Minimum Offer Price Rule (MOPR) which scans new entrants for below-cost bidding into PJM's Capacity Market – called the Reliability Pricing Model (RPM). The FERC agreed and approved the tariff changes.

Q. What was the effect of the FERC's ruling?

A. The net effect was that most new entrants must now bid their full costs into the PJM capacity market.

Q. What problems might this cause?

A. The key problem is that new resources might not "clear" or be selected to provide services to and receive revenues from the capacity market. The market clearing price in these auctions is nearly always below the net cost of new entry. If this should happen, ratepayers could be stuck paying twice for capacity, once to build the new plant and once to buy from the capacity market.

[104] Maryland Public Service Commission, Case 9214, Notice of Comment Period on Request for New Generating Facilities, December 29, 2010, Draft RFP at page 2.

Q. Does Entergy respond to concerns over MISO's proposed capacity market?

A. Yes. Entergy dismisses any concern about MISO's capacity market by saying that any MISO proposal will include a "self supply option,"[105] which would provide another option for the Entergy Operating Companies to procure short term capacity to meet resource adequacy requirements.

Q. Does this position match the options provided in other capacity markets?

A. No, certainly not in PJM. PJM's "opt out" mechanism, called the Fixed Resource Requirement (FRR), allows a utility to specifically designate the plants with which it will serve load. Those plants and load are then removed from the RPM Auction. The FRR is an "all or nothing" option. A utility cannot self-supply some of its requirements via the FRR option and then supplement that with purchases from the RPM Capacity Market.

Q. Is this mechanism controversial?

A. Yes. This "all or nothing" stance has been controversial and has been criticized by several entities in PJM. For example, Dominion Power echoes this concern about the lack of flexibility when it states "the FRR Option is an important one for load serving entities that wants (sic) to opt out of RPM entirely, but it is not a replacement for flexible participation in the market by state-regulated vertically-integrated utilities..."[106]

Q. Why is this "all or nothing" stance a problem?

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[105] Entergy Evaluation Report at page 88.

[106] Request for Rehearing of Dominion Resource Services, Inc. FERC Docket EL11-20-0000, May 12, 2011 at page 10.

A. If a utility uses the FRR, it cannot decide to participate in the capacity market and, will forego any possible benefits from that capacity market. Taking PJM as a precedent, MISO's capacity market would not provide another option as Entergy asserts.

Q. And, again, what is the concern if a utility does not opt out?

A. If a utility does participate in the capacity market, any new baseload or peaking[107] resource it bids into that market will likely be forced to bid its true costs. If the resource does not "clear" the auction, the utility will receive no revenues from the capacity market and ratepayers could be stuck paying twice for capacity – once to build the new plant and once to buy from the capacity market.

Q. What is the takeaway for the Arkansas Commission from these recent experiences?

A. The larger point is that, by joining MISO, Entergy will be part of a capacity market and the capacity market in PJM has put states (New Jersey in particular) at odds with FERC. Unlike MISO, SPP has no plans for a capacity market.

D. Given current regulatory and market conditions, SPP's greater reliance on natural gas-fired capacity could yield both reliability and cost advantages as compared to MISO's greater reliance on coal-fired capacity.

Q. What is the fourth strategic advantage of joining the SPP RTO?

[107] The MOPR applies primarily to natural gas fired combined cycle and combustion turbines.

A. The fourth strategic advantage is that, given current regulatory and market conditions, SPP's greater reliance on natural gas-fired capacity could yield both reliability and cost advantages as compared to MISO's greater reliance on coal-fired capacity.

Q. What is the capacity fuel mix for SPP and MISO?

A. If Entergy joined the SPP RTO, 58% of the capacity would be natural gas- or oil-fired and 27% would be coal-fired. In contrast, if Entergy joined MISO, natural gas- and-oil fired capacity would be a lower share (35% vs. SPP's 58%) and coal-fired capacity would be a much higher share (48% vs. SPP's 27%).

Q. Has Entergy stated an opinion in this regard?

A. Yes. That is, Entergy states that MISO would be "predominantly coal" and that would be a strategic advantage because MISO would have "a more balanced portfolio." Specifically, Entergy states:

> "[T]he combination of MISO and the Entergy Operating Companies produces a more balanced portfolio than does the combination of SPP and the Operating Companies. If the Operating Companies and SPP were to combine, well over half of the total portfolio would be gas-fired units, many of which are more than 40 years old. On the other hand, the combined Entergy Operating Company-MISO portfolio would be predominately coal."[108]

Q. Do you agree with Entergy on this point?

A. No. I do not believe being "predominantly coal" is guaranteed to be a benefit because regulatory and market factors weigh against coal. For example, in terms of regulatory factors, the U.S. EPA's court-ordered enforcement of environmental regulations is

[108] Entergy Evaluation Report at page 80.

pushing up the capital cost of coal-fired power. With respect to market factors, the Shale Gas Revolution is pushing the commodity cost of natural-gas fired power down. Given these two factors, I do not see how Entergy could argue that MISO's greater dependence on coal is guaranteed to be an advantage to Arkansas ratepayers and ratepayers in other Entergy States.

I agree that diversity of fuel type can be an important part of risk management, but we must diversify to the right fuels – diversity just for diversity's sake has no ratepayer benefits. To draw an analogy, we can all agree that diversity in a portfolio of stocks mitigates risk. However, we would be hesitant to buy more of a stock in a company whose profit prospects are poor due to aggressive regulatory enforcement and the rise of a cheaper competitor. Again, it is not just diversity we seek, but a portfolio of stocks with positive profit prospects and uncorrelated risks.

Q. What are you referring to when you say "EPA's court ordered enforcement"?

A. The EPA has proposed four regulations covering: (a) Clean Water Act Section 316(b), Cooling Water Intake Structures, (b) Title I of the Clean Air Act – Maximum Achievable Control Technology (MACT), (c) the Clean Air Transport Rule, and (d) Coal Combustion Residuals Disposal Regulations.[109]

Q. Please give a very brief description of each of these four.

[109] For more information on the four EPA regulations and their impact in SPP, please refer to Boston Pacific Company's *Southwest Power Pool Looking Forward Report*, April 15, 2011, http://www.spp.org/publications/BOD042611.pdf.

A. The Clean Water Act calls for cooling water intake structures in power plants and other facilities to be placed, planned and built using the Best Technology Available (BTA) to reduce adverse environmental impacts.[110] The EPA is developing new standards for these facilities that "withdraw at least 2 million gallons per day of cooling water."[111] A proposed rule was issued on March 28, 2011 and will be finalized by July 2012.[112]

The EPA issued a court-ordered proposed MACT rule to limit mercury and other hazardous air pollutants emitted by "coal- and oil-fired electric . . . generating units" on March 16, 2011.[113] This rule will be finalized by November 16, 2011."[114]

The proposed Clean Air Transport Rule of July 6, 2010 is designed to reduce SO_2 and NO_x pollution that would otherwise travel across state lines and contribute to fine particle and ozone nonattainment areas. It will reduce SO_2 and/or NO_x emissions from electricity generating plants in 31 states and D.C. A final rule is expected to be released in the spring or summer of 2011. The Clean Air Transport Rule replaces the Clean Air Interstate Rule, which was overturned by the U.S. Court of Appeals in 2008.[115]

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[110] EPA, Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities, March 2011, accessed http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/factsheet_proposed.pdf, July 12, 2011, at PDF page 1.

[111] EPA, Clean Water Act Section 316(b) Existing Facilities Proposed Rule Qs and As, March 28, 2011, accessed http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/qa_proposed.pdf, July 12, 2011, at PDF page 1.

[112] News Release from EPA regarding public comment period opening for proposed standards to protect aquatic ecosystems, March 28, 2011, accessed http://yosemite.epa.gov/opa/admpress.nsf/3881d73f4d4aaa0b85257359003f5348/1a6586526d351a1d852578610077d4c8!OpenDocument, July 12, 2011.

[113] EPA, Fact Sheet Proposed Mercury and Air Toxics Standards, accessed http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf , July 12, 2011, at PDF page 1.

[114] Ibid. at page 4.

[115] Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution, accessed http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf, July 12, 2011.

In December 2008, more than 300 acres of land and two rivers were flooded with coal combustion residuals – or coal-ash – from a broken surface containment area in Tennessee. Following the spill, in May 2010, the EPA proposed two options to regulate coal combustion residuals for the first time.[116] These regulations would affect both utilities and independent power producers that own coal plants. The difference is in strictness of the regulations and main implementing agency would be at the federal or state government level.

Q. What would be the impact of EPA's enforcement?

A. The impact of EPA's enforcement could be on both reliability and on costs. With respect to reliability, the concern is that power plants – especially, but not exclusively coal-fired power plants – could be shut down if compliance with these EPA regulations costs too much.

Q. Have there been any estimates of the extent of possible retirements?

A. Yes. From the outset, however, I will note that the results of studies can differ because of the use of different assumptions or different metrics or different geographic footprints. However, I will refer to two studies – one by the Brattle Group and one by NERC – to illustrate the relative impact of EPA's enforcement in MISO and SPP.

Q. What do you take from the Brattle Group Study?

[116] Coal Combustion Residuals – Proposed Rule, accessed http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm, June 24, 2011.

A. The Brattle Group study, dated December 2010, is entitled *Potential Coal Plant Retirements Under Emerging Environmental Regulations*. In that study, the Brattle Group employed a computer model to estimate the retirement of coal-fired plants in the face of the enforcement of the EPA regulations as well as market conditions such as the market price of power. With the assumptions they chose, the Brattle Group concluded that MISO would be in the top three "market areas with the largest retirements."[117] If the EPA enforcement were assumed to set mandates for the installation of scrubbers and selective catalytic reduction on coal plants, Brattle Group estimates that the retirement of coal-fired power capacity would be in the 12 GW to 15 GW range in MISO by 2020. If the enforcement also included cooling tower mandates, the potential retirement could be higher – in the range of 16 to 20 GW by 2020. Brattle estimates that these potential retirements equal 21% to 28% of coal capacity and 11% to 14% of total capacity in MISO.[118] This is a substantial impact.

Q. Would enforcement affect SPP, too?

A. Yes. Have no doubt that EPA's enforcement would affect SPP, too. However, the Brattle Group shows the SPP RTO impact to be much smaller – about 0.6 GW of coal-fired capacity retirements versus the 12 GW of potential retirements cited above for MISO.[119]

Q. What was the NERC study you mentioned?

[117] The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, at page 8.
[118] Ibid.
[119] Ibid. at page 32.

A. The NERC study, dated October 2010, is entitled *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential Environmental Regulations*. Again, I will note that differences in assumptions, metrics, and footprints can make a difference among the various studies. In particular, I will note that NERC assesses potential retirements of all fuel types, not just coal. However, NERC gets right to the reliability issue I raised.

Q. What did NERC find?

A. NERC estimates the percentage change in reserve margins resulting from the enforcement of these environmental regulations in each of the NERC regions. There is a range of impacts because NERC reflects the uncertainty on how strict EPA will be in enforcement. For SPP, in the year 2018, the "percentage change in the reserve margin" ranges from a reduction of 2.6% in the moderate case to a reduction in reserve margin of 5.3% in the strict case.[120]

There is no NERC estimate for MISO *per se* since MISO is spread across more than one NERC region. However, we can look at the results for three NERC regions – MRO, RFC, and SERC Gateway – to get a sense of the potential impact in MISO. For MRO, the range of reductions in reserve margins for the moderate and strict case is from a reduction of 4.4% to a reduction of 10.6%. For RFC, the range of reductions is from 5.1% to 9.2%. And for SERC Gateway, the range of reductions is from 5.2% to 18%.[121]

[120] NERC, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, at page 39.
[121] Ibid.

The point is that, while EPA's enforcement will have an impact on resource adequacy in both SPP and MISO, the impact in MISO is expected to be much more significant. From this, we can conclude that SPP's capacity mix by fuel type – including its greater dependence on natural gas – is a strategic advantage in terms of mitigating the impact of EPA's regulation.

Q. What do you mean by "market conditions"?

A. One market condition of interest is what many refer to as the Shale Gas Revolution – the view that new technologies for finding and producing natural gas have opened up significant reserves and, thereby, have increased supply and reduced prices significantly.

Q. Do you see factual indications of this "revolution"?

A. Yes. We see indications of the revolution in estimates of natural gas reserves. For example, in just two years (from 2006 to 2008), the Potential Gas Supply Committee increased its estimate of total potential resources by 39%.[122] I also see signs of this fundamental change in views about the likely price of natural gas in the near-term. A futures price indicates the price someone would be willing to guarantee at some future date. As to future date, let's use the average price for all twelve months of 2012 for our purposes here. Soon after the natural gas price spike in 2008 the expectation was that the average price for natural gas in the future – the average price across the twelve months of 2012 – would be $10.74 per MMBtu. Moving to the Fall of 2010, the futures prices indicate that the average price in 2012 is expected to be $4.89 per MMBtu – a decrease of

[122] News Release from Colorado School of Mines regarding Potential Gas Committee Report, June 18, 2009, http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base.

54%.[123] Looking again at future prices in March 2011, we see that the average price in 2012 still is expected to be low – about $4.77 per MMBtu.[124] Finally, I see the Shale Gas Revolution illustrated in long-term forecasts of natural gas prices. Within just one year, the U.S. Energy Information Administration (EIA) lowered their Henry Hub Spot Price forecast by an average of 22% across years 2015-2035 in their Annual Energy Outlook.[125]

Q. What is the potential strategic advantage to ratepayers?

A. If the Shale Gas Revolution holds natural gas prices down, SPP's greater dependence on natural gas-fired capacity could yield direct cost savings – using more natural gas would directly reduce the cost of power to ratepayers.

Q. Are low natural gas prices guaranteed?

A. No. There are no guarantees and natural gas prices could be much higher than expected. If natural gas price do go higher rather than lower, however, there still could be a narrower strategic advantage related to fuel for Entergy Arkansas in joining SPP. With higher natural gas prices, sales of Entergy Arkansas' coal and nuclear power might be more profitable in natural gas-dependent SPP than in coal- and nuclear-dependent MISO. Driving this point home is that fact that, in SPP, natural gas prices now set the real-time

[123] Futures prices are downloaded from NYMEX for settlement dates 6/30/2008 and 11/16/2010 and are the simple averages of the 12 months worth of futures for 2012.

[124] Futures prices are downloaded from NYMEX for settlement date 3/11/2011 and are the simple averages of the 12 months worth of futures for 2012.

[125] The 22% is calculated by taking the simple average of the difference in Henry Hub spot prices between the values reported in the 2010 and 2011 EIA Annual Energy Outlook Report for each year from 2015 to 2035. The 2011 prices are converted from 2009 dollars to 2008 dollars using the GDP deflator.

energy price 62% of the time while natural gas-, oil- and dual-fired plants prices drive power prices in MISO only 23% of the time.

Q. Are there any other strategic advantages to SPP's greater reliance on natural gas that you want to note?

A. Yes. Natural gas-fired power plants – especially natural gas-fired combined cycle plants – are thought to be important for accommodating wind power. SPP estimates that combined cycle power plants will account for 15% to 20% of SPP total capacity and that in 2010, these combined cycle plants were at the margin in SPP's real time market 44% of the time.[126]

E. The SPP RTO transmission planning process and cost allocation method are driven by benefits before and after transmission investments are made.

Q. What is the fifth strategic advantage of joining the SPP RTO?

A. The fifth strategic advantage is that the SPP RTO transmission planning process and cost allocation method are driven by benefits before and after transmission investments are made.

Q. Does Entergy agree with your view?

[126] Southwest Power Pool, Board Of Directors/Members Committee Meeting Minutes, April 26, 2011, *Combined-Cycle Market Working Group Report*, March 2011, at page 2.

A. Apparently not. Entergy repeatedly criticizes SPP saying that transmission costs are "socialized." And Entergy repeatedly praises MISO for letting benefits drive transmission cost allocation. For example, Entergy stated:

> "Nonetheless, the Operating Companies believe that the MISO cost allocation methodology better aligns with the Operating Companies' historic preference for allocating costs in relation to benefits. As discussed in more detail below, MISO's methodology places more of a focus on aligning costs and benefits than SPP's methodology. Whereas SPP's methodology socializes all costs above a certain voltage threshold and assumes that projects of that voltage result in regional benefits – regardless of whether they are reliability projects or economic projects – MISO's methodology does not automatically socialize projects above a certain voltage level."[127]

Entergy even mischaracterizes a feature of the SPP cost allocation method – commonly called the Unintended Consequences process – meant to assure that benefits align with costs after transmission investment have been made. Entergy stated:

> "SPP's proposal, on the other hand, involves an undefined "unintended consequences" review, under which the Operating Companies' customers may be allocated additional costs for SPP's Priority Projects or other high voltage upgrades."[128]

Q. Why do you conclude that SPP's planning process and cost allocation method are driven by benefits?

A. I would point primarily to three features to support my conclusion: (a) a transmission investment must be shown that it is needed for reliability or will generate benefits before it is included in SPP's Integrated Transmission Plan or ITP; (b) SPP's Highway/Byway Cost Allocation is based on a showing of benefits; and (c) SPP has an ongoing process to

[127] Entergy Evaluation Report at page 88.
[128] Ibid. at page 23.

ensure equity in cost allocation after transmission investments are made – this is the Unintended Consequences process.

Q. Let's discuss each of the three in turn. Please discuss your point related to SPP's ITP.

A. To qualify for regional cost allocation – for what Entergy calls socialization – a proposed SPP transmission project must show that it is needed for reliability or otherwise generates benefits in the ITP process. As part of the ITP process, a project would have to show that it solves a reliability problem or provides net benefits in the form of some combination of dispatch savings, loss reductions, congestion reduction, avoided projects, reduction in required operating reserves, applicable environmental impacts, and/or other benefits. Projects are selected for inclusion in the ITP based on this showing of reliability or other benefits.

Q. Please discuss your point related to the Highway/Byway cost allocation.

A. Under this policy, SPP assigns costs of projects with a voltage greater than 300 kV on a regional basis. However, the decision to allocate the cost of 300-kV and higher voltage facilities on a regional basis was itself based on an assessment of benefits. SPP's own studies showed that 300-kV and higher voltage facilities created significant regional benefits and lower voltage facilities did not. Indeed, in its Order approving the Highway/Byway method, the FERC acknowledged these benefits. The FERC Order states: "We also find that SPP has demonstrated that the benefits of the [extra high voltage] facilities accrue to all members of its system."[129] The FERC added that:

[129] *Southwest Power Pool, Inc.,* 131 FERC ¶ 61,252 (2010) (FERC Highway/Byway Order) at paragraph 75.

> "We find SPP's Transmission Distribution Analysis demonstrates that [extra high voltage] facilities tend to support regional power flows among the SPP zones and that lower voltage facilities tend to support local power flows within a single SPP zone…We find this evidence compelling that the high voltage 345kV and [extra high voltage] facilities provided significantly greater support to regional power flows relative to the lower voltage facilities."[130]

Consistent with this, only one-third of the cost of investments in 100 kV to 300 kV projects is allocated regionally.

Q. Do you think the FERC sees a difference in this fundamental principle of linking costs to benefit in the SPP and MISO approaches to cost allocation?

A. No. My view is that, in FERC's eyes, SPP and MISO's cost allocation methods both meet this principle. In accepting MISO and SPP's cost allocation methods, the FERC used nearly identical language. In its Order for SPP, the FERC stated:

> "Moreover, by distinguishing between the types of facilities that are used on a regional and zonal basis, the Highway/Byway Methodology *will ensure* that allocations of costs are *roughly commensurate with associated benefits*."[131] (emphasis added)

Similarly, in its MISO Order the FERC stated: "[T]he MVP Methodology *will ensure* that allocations of costs are *roughly commensurate with associated benefits*."[132] (emphasis added)

Q. Why do you think the FERC uses the term "roughly"?

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[130] Ibid. at paragraph 73.
[131] Ibid. at paragraph 78.
[132] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221 (2010) at paragraph 236.

A. I think the FERC uses the term "roughly" because transmission cost allocation is not an exact science; the best SPP or MISO can do is to "roughly" assign costs to beneficiaries. In the SPP Order, the FERC quotes the U.S. Supreme Court as saying: "[A]llocation of costs is not a matter for the slide rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[133] Further, the FERC stated that benefits can change over time:

> "Furthermore, cost-benefit analyses often evaluate benefits at a distinct point in time. Because power flows change constantly with fluctuations in generation and load, as well as the addition of new transmission facilities, generation resources, and loads to the system, such static analyses cannot capture all benefits over time. Therefore, relying solely on the costs and benefits identified in a quantitative study at a single point in time may not accurately reflect the true beneficiaries of a given transmission facility, particularly because such tests do not consider any of the qualitative, (i.e., less tangible) regional benefits inherently provided by an [extra high voltage] transmission network."[134]

Q. Does the SPP process have a way to mitigate FERC's concern with benefits changing over time?

A. Yes. The mitigation is the Unintended Consequences provision. The Unintended Consequences provision is an ex post test to make sure that those parties that benefit from a transmission project are those that pay for it. Entergy misread and misstated the purpose of this provision. This provision is exactly what Entergy seeks when it says that it wants cost to be assigned to those who benefit from transmission investment. Under the provision, SPP member companies are able to seek relief from any transmission cost allocation that exceeds the portion that more accurately reflects the benefits they accrue from a project.

[133] *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945).
[134] FERC Highway/Byway Order at paragraph 76.

Q. Can other parties use the Unintended Consequences provision?

A. Yes. Notably, the Arkansas Commission and the other State Commissions in the RSC can recommend any adjustments to the cost allocation if a review shows an imbalanced cost allocation to one or more zones and require that the analytical methods used in the review be defined. This means Arkansas and the other RSC States have a continuing voice in cost allocation. Again, I will draw attention to the fact that the RSC has an explicit role in transmission cost allocation, and the RSC approved both the Highway/Byway method and the Unintended Consequences provision.

V. CONCLUSIONS

Q. What do you conclude based on your Testimony?

A. I conclude that the best "strategic reorganization option" is for EAI and the other Entergy Operating Companies to join the SPP RTO. I base my conclusion on the fact that (a) the latest analysis by the independent consultant, CRA, found that joining SPP would be likely to provide greater net benefits to the Entergy region and (b) five strategic advantages also clearly make joining SPP the better choice.

Q. Does this end your Testimony?

A. Yes.

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF A SHOW CAUSE ORDER	)	
DIRECTED TO ENTERGY ARKANSAS, INC.	)	
REGARDING ITS CONTINUED MEMBERSHIP	)	
IN THE CURRENT ENTERGY SYSTEM	)	CASE NO: 10-11-U
AGREEMENT, OR ANY SUCCESSOR	)	
AGREEMENT THERETO, AND REGARDING	)	
THE FUTURE OPERATION AND CONTROL	)	
OF ITS TRANSMISSION ASSETS	)	

AFFIDAVIT OF CRAIG R. ROACH

WASHINGTON	)	
	)	SS.
DISTRICT OF COLUMBIA	)	

I, Craig R. Roach, President of Boston Pacific Company, Inc., being first duly sworn, state that I have reviewed the above and foregoing Testimony, and state that the matters contained herein are true and accurate to the best of my knowledge, information, and belief.

Dated this the 12th day of July, 2011.

Craig R. Roach

Craig R. Roach

Sworn to and subscribed before me this the 12th day of July, 2011.

Glenn W. Stevens

Notary Public

My Commission Expires:

GLENN W. STEVENS
Notary Public, District of Columbia
My Commission Expires Dec. 14, 2011

ATTACHMENT NO. CRR-1:

LIST OF TESTIMONY AND OTHER PUBLICATIONS

FOR CRAIG R. ROACH, Ph.D.

LIST OF TESTIMONY AND OTHER PUBLICATIONS
FOR CRAIG R. ROACH, Ph.D.

TESTIMONY

Expert Report concerning HydroQuebec's calculations of ATC and its transmission planning process, Régie de l'énergie, No. R-3669-2008, Phase 2, [September 2010]. Filed on behalf of Énergie Brookfield Marketing, Inc.

Expert Report concerning rollover rights and curtailment under HydroQuebec's OATT, Régie de l'énergie, Nos. P130-001 and P130-003 [July 2010] Filed on behalf of Énergie Brookfield Marketing, Inc.

Direct and Supplemental Testimony concerning the application of Oklahoma Gas and Electric Company to construct the Crossroads wind farm, Cause No. PUD 201000037 [June 2010]. Filed on behalf of The Oklahoma Corporation Commission.

Report on the Open Season for Zephyr Power Transmission LLC, Federal Energy Regulatory Commission, Docket No. ER09-433-000 [May 2010]. Filed as the Independent Evaluator for Zephyr Power Transmission, LLC.

Phase Two Report of the Independent Evaluator concerning proposed alternatives to Mississippi Power Company's IGCC facility, Docket No. 2009-UA-014 [January 2010]. Filed as Consultant to the Mississippi Public Service Commissioners.

Phase Two Direct Testimony concerning Mississippi Power Company's proposed IGCC facility, Docket No. 2009-UA-014 [December 2009]. Filed as Consultant to the Mississippi Public Service Commissioners.

Phase One Direct Testimony concerning Mississippi Power Company's petition for acquisition, construction, and operation of an Integrated Gasification Combined Cycle (IGCC) facility, Docket No. 2009-UA-014 [July 2009]. Filed as Consultant to the Mississippi Public Service Commissioners.

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Comments concerning the 2008 Procurement Process, before the Illinois Commerce Commission [May 2008]. Filed as the Procurement Monitor.

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Comments on the Maryland procurement process for Standard Offer Service, Maryland Senate Special Commission on Electric Utility Deregulation Implementation. [August 2005]. Appearing as the Technical Consultant for the Maryland Public Service Commission.

Direct and Supplemental Testimony concerning market power mitigation measures for the Southwest Power Pool energy imbalance services market, Federal Energy Regulatory

Commission Docket No. ER05-1118-000. [June and August 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

Comments on the open access status of a transmission line, Federal Energy Regulatory Commission Docket No. ER05-1072-000. [June 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

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Direct and Answering Testimony and Cross-Answering Testimony concerning approval of an affiliate acquisition by AmerenUE under the *Edgar* standard using a competitive solicitation and benchmark data. Federal Energy Regulatory Commission Docket No.

EC03-53-000. [August and September 2003]. For the Electric Power Supply Association.

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Expert Report concerning the correct discount rate to be used in determining an award, American Arbitration Association Case No. 00 199 00199 02. [March 2003]. For TM Delmarva Power L.L.C.

Affidavit concerning market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER03-618-000. [March 2003]. For Reliant Energy Choctaw, LLC.

Expert Report concerning opportunities for reverse tolling transactions with Entergy, utility dispatch rules, and antitrust damages, Louisiana State Court Suit No. 467,116; Div. "N". [January 2003]. For Energy Transfer Group.

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CERTIFICATE OF SERVICE

I, Erin E. Cullum, attorney of record for Southwest Power Pool, Inc., do hereby certify that I have, on this 12th day of July, 2011, duly served a true and correct copy of the above and foregoing pleading upon all parties of record by electronic mail.

Erin E. Cullum

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