BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

STAFF RESPONSE TO MARCH 1, 2017 AGENDA DISCUSSION ITEM

COMES NOW the Staff of the Missouri Public Service Commission ("Staff"), by and through Staff counsel, and submits certain documents based on the discussion that occurred at the March 1, 2017, Commission Agenda regarding "Case Discussion, Item No. 1, File No. EO-2011-0128, Ameren Missouri's Continued Membership in MISO." As a consequence thereof, undersigned Staff counsel states as follows:

1. During the course of the Commissioners' discussion at the March 1, 2017, Agenda, regarding the item "Ameren Missouri's Continued Membership in MISO," undersigned Staff counsel indicated that he could provide the Commissioners' with the 2007 cost / benefit study performed by CRA International ("Charles River Associates") for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") that was filed with the Commission in another Ameren Missouri request to continue to participate in MISO case. Undersigned Staff counsel also indicated that he might be able to provide a list of cost / benefit items / areas that the parties to this proceeding had at one time reviewed as the possible items / areas to be looked at for a cost / benefit study regarding Ameren Missouri's continued participation in MISO.

2. Attached as Exhibit A is a copy of the 2007 cost / benefit study performed by CRA International that was filed on November 1, 2007 by Ameren Missouri in Case

No. EO-2008-0134.[1] Attached as Exhibit B is a two page agenda prepared by Ameren Missouri for the meeting of parties to this proceeding that was held on September 25, 2014, to discuss the 2015 cost / benefit study that was to be performed, but was postponed by the request of some of the parties and the Commission's December 22, 2014, Order Modifying 2012 Report And Order. The possible scope of the cost / benefit study is discussed at the bottom of page one and the top half of page 2 of Exhibit B.

3. Finally, undersigned Staff counsel would note that the Direct Testimony (presently Item No. 81) and the Surrebuttal Testimony (presently Item No. 113) of Ameren Missouri witness Ajay Arora in the instant case, EO-2011-0128, addresses the 2010 updated cost / benefit analysis performed by Ameren Missouri for the Application filed on November 1, 2010 that was based on the 2007 CRA study.

4. At the same time that the Staff is providing these documents and information, it wants to be clear that the Staff continues to be one of the Joint Movants and continues to support the extension of the date by which a further cost / benefit study will be performed as addressed by the January 23, 2017, Joint Motion to Make Additional Modifications to April 19, 2012 Report and Order.

WHEREFORE, the documents and information identified above are being provided as undersigned Staff counsel indicated at the March 1, 2017, Agenda they would be.

[1] In the Matter of the Application of Union Electric Company d/b/a AmerenUE for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System Operator, Inc.

Respectfully submitted,

/s/ Steven Dottheim

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served via e-mail on counsel for the parties of record to this case, on this 6th day of March, 2017.

/s/ Steven Dottheim

RTO Cost-Benefit Analysis

AmerenUE

Prepared By:

CRA International

October 11, 2007

Exhibit A

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1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

CRA International ("CRA") has conducted a cost-benefit analysis on behalf of AmerenUE to assess the costs and benefits of continued AmerenUE membership in the Midwest Independent System Operator ("Midwest ISO")[1]. AmerenUE serves 1.2 million electric customers in eastern Missouri, including the St. Louis area. Other investor-owned utilities with service territories in Missouri[2] are currently members of the Southwest Power Pool RTO ("SPP RTO")[3]. AmerenUE joined the Midwest ISO in 2004 under an interim five-year term of approval by the Missouri Public Service Commission. Under that interim approval, approximately 18 months before the end of the five-year term, AmerenUE is required to file an analysis of the costs and benefits of continued Midwest ISO membership.

Recently, Louisville Gas & Electric ("LG&E") exited the Midwest ISO and contracted with an independent coordinator of transmission ("ICT") to coordinate the operation of LG&E's transmission system. Entergy, Duke Power, and MidAmerican Energy have entered into similar contractual arrangements with ICTs.[4] As such, in this study three potential alternatives were evaluated for Ameren UE beginning in 2009: 1) Continued membership in the Midwest ISO ("Midwest ISO case"), 2) Membership in the SPP RTO ("SPP case"), or 3) Entering into a contract with an ICT to coordinate the operation of the AmerenUE transmission system ("ICT case").[5]

1 The Midwest ISO covers all or part of the Canadian province of Manitoba and 15 Midwestern states, including portions of Missouri and the neighboring states of Iowa and Illinois. The market operated by the Midwest ISO provides a security-constrained unit commitment reflecting the marginal cost of providing for transmission losses, and operates a day-ahead market, a real-time market, and a financial transmission rights market.

2 These Missouri utilities include Kansas City Power and Light ("KCP&L") and Empire District, members of the SPP RTO, and Aquila Missouri which is a transmission owner under the SPP tariff. In this study, the Ameren operating companies located in Illinois are assumed to remain in the Midwest ISO.

3 SPP was originally formed as a reliability council, and covers all or parts of eight south central states, including Missouri and the neighboring states of Arkansas, Kansas, and Oklahoma. Most, but not all, of the load-serving entities in the SPP reliability region are currently members of the market operated by the SPP RTO. The SPP RTO began operation of a real-time market on February 1, 2007.

4 The specific names of these independent coordinators of transmission differ. For purposes of this study, all of them are referred to as ICTs.

5 AmerenUE is a member of the SERC reliability council. For purposes of this study, AmerenUE is assumed to remain in the SERC reliability council in all cases.

As discussed in further detail below, we have found that continued membership in the Midwest ISO provides significantly more benefits to AmerenUE than membership in the SPP RTO or contracting with an ICT. One of the main drivers of these significant benefits is the post-transition revenue distribution received by AmerenUE as a member of the Midwest ISO.

1.2. METHODOLOGY

The time horizon for this study is the 10-year period from 2009 through 2018. CRA has performed GE MAPS model runs for each of the three cases (Midwest ISO, SPP, and ICT) over this period. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element in the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was recently used by CRA to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study required by the Energy Policy Act of 2005.

The GE MAPS was modeled to reflect different impediments to AmerenUE trade under each case. The impediments to trade applied in this study are commitment and dispatch seams charges. Commitment seams charges reflect that a control area with responsibility for reliably committing generating units for operation the next day cannot fully rely on units outside of the control area over which the control area has no direct control. The dispatch seams charges reflect impediments to trade that take place on a real-time basis, including wheeling charges and imperfect knowledge regarding flows outside of the control area. In this study, for RTOs with day-ahead markets, the unit commitment seams charge was set at zero within the RTO and at $10/MWh between the RTO and adjoining control areas. The commitment seams charge was set at $10/MWh between all other control areas. Dispatch hurdles were set at applicable non-firm off-peak wheeling rates plus a dispatch friction rate. For RTOs with active managed markets, the frictional rate was set at zero for flows within the RTO, and at 3 $/MWh for flows out of the RTO. For flows out of all other control areas, the frictional rate was set at 5 $/MWh.

The differences in seams charges between cases serve to alter impediments to AmerenUE trade. In this study, trade benefits are measured as the decrease in the total cost to serve AmerenUE load in the SPP case or the ICT case relative to the Midwest ISO case. The major elements in the total cost to serve AmerenUE load as measured in this study are:

1. AmerenUE energy revenues at LMP for owned capacity generation
2. *(minus)* AmerenUE production costs for owned capacity
3. *(minus)* Ameren UE load withdrawals at LMP
4. *(plus)* the value of AmerenUE financial transmission rights ("FTRs") at LMP
5. *(minus)* AmerenUE net operating reserve costs
6. *(plus)* AmerenUE marginal loss credits
7. *(plus)* AmerenUE capacity sale revenues

8. *(plus)* net through and out AmerenUE wheeling revenues.[6]

These trade benefits must be compared to the change in administrative and other charges that AmerenUE would incur by moving to the SPP RTO or an ICT. The administrative and other charges quantified in this study are:

- RTO administrative charges and ICT contractual charges,
- Revenue Sufficiency Guarantee (“RSG”) and Revenue Neutrality (“RNU”) payments,
- Transmission cost allocations in the RTO cases,
- Post-transition revenue distribution in the Midwest ISO case,
- Reconfiguration costs if leaving the Midwest ISO, and
- FERC administrative charges.

The AmerenUE trade benefits and the change in administrative and other charges that AmerenUE would incur by moving to the SPP RTO or an ICT are combined to arrive at the overall level of net benefits for each case.

1.2.1. Midwest ISO Modeling

The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights (“FTRs”). In addition, the Midwest ISO has formal plans and budgeting to institute an ancillary services market. AmerenUE’s administrative costs in the Midwest ISO for the study period were estimated using Midwest ISO projections of charge rates applied to projections of generation, load and other billing determinants used to assess Midwest ISO charges. The Midwest ISO was modeled in GE MAPS with an ancillary services market in place. The associated AmerenUE administrative charges for the operation of the ancillary services market were estimated using Midwest ISO projections. The MISO/PJM seams management is assumed to yield a 1 $/MWh reduction in the dispatch seams charge between these two RTOs.

1.2.2. SPP RTO Modeling

Currently, the Midwest ISO and SPP RTO markets are in different stages of development. The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs over the next few years that are approximately 20% lower per MWh of market member net energy for load than that of the Midwest ISO.

[6] Fixed costs that do not change between cases, such as depreciation for owned-generating units are not included in this measure.

The costs and benefits of RTO market development require formal and complex study and evaluation. It is anticipated that the SPP RTO will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. For purposes of this cost-benefit study, it is assumed that the SPP RTO market will become similar in overall design to that of the Midwest ISO beginning in 2011. At that time, it is assumed that the SPP RTO administrative charges to AmerenUE will be similar to those projected by the Midwest ISO.

Prior to 2011, SPP is modeled with the standard $10/MWh commitment seams charges between SPP control areas to model that the SPP commitment is not RTO-wide. Intra-RTO SPP dispatch seams charges are reduced to $1/MWh to take into account the balancing market that is in operation in SPP. The current set of FTRs that AmerenUE has in the Midwest ISO was assumed to continue to apply in the SPP case.

1.2.3. ICT Modeling

Publicly available information regarding the administrative costs paid to an ICT by Duke, Entergy, LG&E, and MidAmerican Energy were reviewed. The LG&E ICT costs included the provision by the ICT of all of the standard transmission and reliability functions (albeit from two different ICT vendors) for a cost of approximately $5 million per year, and was judged to be the best estimate of the charges that would be paid by AmerenUE to an ICT.

The ICT case was modeled with the standard $10/MWh commitment seams charge and $5/MWh ($6/MWh with the AmerenUE wheeling charge included) dispatch seams charge between AmerenUE and all adjoining entities, including the SPP RTO, the Midwest ISO, Entergy, AECI, TVA, and MidAmerican. In practice, in an ICT case AmerenUE would not hold FTRs or have separate LMPs for generation and load within the AmerenUE control area. However, for analytic purposes, to maintain consistency across the three cases, AmerenUE generation and load LMPs from GE MAPS were applied in the ICT case to derive trade benefits, and the same set of FTRs as used in the Midwest ISO case were used adjust for congestion between these generation and load LMPs.

The seams charges that were applied to AmerenUE seams are summarized in Table 1. As described above, applicable wheeling charges are also added to these figures (for example, an additional $1/MWh for exports to adjoining regions in the AmerenUE ICT case).

Table 1
Ameren UE Seams Charge Modeled
(before addition of applicable wheeling charges)

With AmerenUE as Member of:	AmerenUE Seams Charges to: Midwest ISO		SPP RTO		Others	
	Commit	Dispatch	Commit	Dispatch	Commit	Dispatch
Midwest ISO	0	0	10	3	10	3
SPP: 2009-2010	10	3	10	1	10	3
SPP: 2011-2018	10	3	0	0	10	3
ICT	10	5	10	5	10	5

1.3. Findings

1.3.1. Net Benefits of Joining an RTO

As shown in Table 2, the quantitative findings indicate that becoming a member of the SPP RTO or formation of an ICT are considerably less beneficial to AmerenUE than continued membership in the Midwest ISO. The results are presented in terms of the mid-2008 present value of net benefits.[7]

Table 2
Benefits (Costs) to AmerenUE of the SPP RTO and ICT Cases in comparison to Continued Midwest ISO Membership
(in millions of 2008 present value dollars; positive numbers are benefits)

	SPP Case		ICT Case	
	2009-11	2009-18	2009-11	2009-18
Trade Benefits	(94)	(221)	(92)	(194)
Savings in Administrative and Other Charges	(109)	(342)	(61)	(152)
Total Benefits (Costs)	**(203)**	**(563)**	**(153)**	**(346)**

As shown in Table 2, the trade benefits of joining the SPP and ICT cases are negative. That is, the net cost to serve AmerenUE load increases in the SPP and ICT cases relative to continued membership in the Midwest ISO. In addition, the SPP and ICT cases result in increased levels of administrative and other charges. Overall, formation of an ICT is projected to yield a $153 million decrease in net benefits to AmerenUE over the 2009 to 2011 period relative to continued membership in the Midwest ISO, and a $346 million decrease in net benefits over the 10-year study period. SPP RTO membership relative to continued

7 GE MAPS runs were performed for the calendar years 2009, 2011, 2014 and 2016 with results for intervening years interpolated, and results for 2017 and 2018 extrapolated at the 2016 results. A present value rate of 8.9% was applied, consistent with AmerenUE's after-tax cost of capital. An underlying inflation rate of 2.5% was assumed.

membership in the Midwest ISO is projected to yield a $563 million decrease in net benefits to AmerenUE over the 10-year study period.

Trade benefits arise from both selling and purchasing activity. AmerenUE is a net seller of energy throughout the 2009 to 2018 period in all three cases. However, the generation of the AmerenUE units decreases significantly in the SPP and ICT cases as shown in Table 3.

Table 3
Change in AmerenUE Generation in Comparison to Midwest ISO Case (GWh)

	2009	2011	2014	2016
SPP Case	(3,003)	(2,942)	(2,672)	(2,587)
ICT Case	(4,135)	(3,029)	(2,831)	(2,193)

This decrease in AmerenUE generation could result in trade benefits for the SPP and ICT cases if AmerenUE generation were replaced by lower-cost purchases. However, as shown in Table 4, the AmerenUE trading activity (i.e., the sum of purchases and sales) also declines significantly in the SPP and ICT cases. This decline indicates that the reduction in AmerenUE generation in the SPP and ICT cases is largely foregone off-system sales. In the Midwest ISO case, the average annual AmerenUE operating margin for generation (generator revenue net of production cost) ranges from $17 to $22 per MWh (2007 dollars) over the 2009 to 2018 period in the Midwest ISO case. Foregone off-system sales are thus a key driver in the reduction in trade benefits in the SPP and ICT cases.

Table 4
AmerenUE Trading Activity: Off-System Sales plus Purchases (GWh)

	2009	2011	2014	2016
Midwest ISO Case	9,745	8,423	8,470	8,052
SPP Case	6,895	5,862	6,094	5,672
ICT Case	5,556	4,983	5,125	5,112

The decline in trade benefits in the SPP and ICT cases is combined with the impact on administrative and other costs shown in Table 5.

Table 5
Savings in AmerenUE Administrative and Other Costs in the SPP RTO and ICT Cases in Comparison to Continued Midwest ISO Membership
(in millions of 2008 present value dollars; positive numbers are benefits)

	SPP Case		ICT Case	
	2009-11	2009-18	2009-11	2009-18
Savings in Administrative Charges	9.4	(0.9)	29.0	67.4
Savings in RSG and RNU Payments	31.7	31.7	45.6	116.0
Savings in Transmission Cost Allocations	1.1	4.4	6.8	31.1
Lost Midwest ISO Post-Transition Revenue Distribution	(146.7)	(372.9)	(146.7)	(372.9)
Savings in Other Charges	(8.1)	(8.1)	(6.0)	(3.8)
Total Savings in Administrative and Other Costs	(109.1)	(342.2)	(61.4)	(152.4)

As shown, the significant levels of AmerenUE RSG and RNU payments in the Midwest ISO case are a key factor contributing to administrative cost savings. The AmerenUE RSG payments that result from the RSG allocation procedures in the Midwest ISO tariff have been the subject of complaints filed by AmerenUE at FERC in proceedings over the last several years. The Midwest ISO has developed a task force to help address this issue, and some mitigation of the AmerenUE RSG costs through a redesign of the RSG allocation process is included in the figures used in this study.

In contrast, the loss of the post-transition revenue distribution to be received by AmerenUE under continued membership in the Midwest ISO is the significant factor contributing to additional administrative costs in the SPP and ICT cases. The Midwest ISO post-transition period begins in February 2008.

1.3.2. Sensitivity Analyses

Six one-year sensitivity analyses were conducted, including: 1) high fuel prices in 2011, 2) Taum Sauk's return to service being delayed further (the base case assumes a 2011 return), 3) a $2/MWh higher ICT dispatch seams charge in 2011, 4) a $2/MWh lower ICT dispatch seams charge in 2011, 5) institution of a carbon tax in 2014, and 6) commercial operation of a second nuclear unit at the Callaway station in 2016. The one-year impact on net benefits of each sensitivity case is shown in Table 6.

Table 6
Increase in One-Year Net Benefits in Sensitivity Analyses
(Nominal dollars)

	SPP Case	ICT Case
High Fuel Price in 2011	(2)	(15)
No Taum Sauk in 2011	7	8
Higher ICT Seams Charge in 2011	NA	(3)
Lower ICT Seams Charge in 2011	NA	3
Carbon Tax in 2014	(86)	(19)
Callaway 2 in 2016	(11)	(1)

As shown, the one-year benefits in the ICT case are reduced with high fuel costs and carbon taxes. The natural gas prices in the base forecast decrease from today's levels through 2016 in real terms before beginning to increase. To the extent that this decrease in fuel prices does not take place, the ICT case would be at risk for additional costs. The increase (decrease) in the ICT seams charge reduces (increases) ICT case benefits, although not by a large amount. National carbon-control regulations are unlikely to take effect for at least several years in the future, with the exact formulation of those regulations, if any, unknown.

1.3.3. Qualitative Considerations

Qualitative considerations, at least in the near term, indicate that additional upward cost risk would be faced in the ICT case in comparison to the Midwest ISO case. These qualitative risks faced in the ICT case include the:

- Availability, and associated potential cost for transmission if available, in the ICT case for AmerenUE to make off-system sales,
- Amount of through and out wheeling revenues that would be received in the ICT case in practice, and
- Impact of exit fees and hold harmless provisions that could take place if AmerenUE were to exit the Midwest ISO.
- The greater impact on ICT case benefits of an increase in fuel prices, particularly gas prices, and the implementation of carbon controls.

Moreover, the costs in the Midwest ISO case include considerable expenditures for RSG and RNU payments that the Midwest ISO is evaluating how to reduce in the future. On the other hand, the allocation of RTO regional transmission costs to AmerenUE has the potential to worsen in the Midwest ISO case depending on how much new regional transmission is built and how that transmission cost is allocated to AmerenUE. In addition, the Midwest ISO ancillary services market is not yet in place and may result in additional costs (or benefits) than modeled herein. Finally, the net receipt of Midwest ISO post-transition revenue by

AmerenUE under continued Midwest ISO membership is subject to uncertainty related to the treatment of bundled load for other Midwest ISO members.

The results of the quantitative analysis show significant benefits to AmerenUE of continued membership in the Midwest ISO. Further review of these cases in the future may be warranted as market rules and structures evolve and additional information is known about the Midwest ISO ancillary service market, the control of RSG and RNU payments, and the Midwest ISO post-transition revenue distribution to AmerenUE.

2. ANALYTIC FRAMEWORK

In this study, it is assumed that AmerenUE will remain a member of the Midwest ISO, move to the SPP RTO, or contract with an ICT to coordinate the operation of the AmerenUE transmission system.

2.1. CASES ANALYZED

CRA modeled three alternative cases for AmerenUE in this study:

- **Midwest ISO case.** AmerenUE continues as a full member of the Midwest ISO participating in all markets and paying all applicable administrative costs.
- **SPP case:** AmerenUE joins the SPP RTO as a full member of the RTO participating in all markets and paying all applicable administrative costs.
- **ICT case.** AmerenUE engages an ICT to coordinate the operation of the AmerenUE transmission system, and provide transmission- and reliability-related functions including reliability coordination, tariff administration, OASIS administration and ATC/AFC/TTC calculations.

In this study, the Midwest ISO case is used as the reference case from which changes in costs and benefits are measured.

The time horizon for the study consists of the 10-year period from 2009 through 2018. No new AmerenUE capacity was assumed to be placed in service during the study period. Taum Sauk was assumed to return to service in January 2011. AmerenUE is a member of the SERC reliability council. For purposes of this study, AmerenUE is assumed to remain in the SERC reliability council in all cases.

In addition to the base analysis over the 10-year study period, six sensitivity cases were conducted, each for one year only:

- A high fuel cost sensitivity was performed for 2011.
- Taum Sauk was assumed to not be in operation in 2011.
- A $2/MWh increase in the ICT seams charge in 2011.
- A $2/MWh decrease in the ICT seams charge in 2011.
- A carbon tax case was conducted for the year 2014.
- Commercial operation of a second nuclear unit at the Callaway station in 2016.

2.2. COSTS AND BENEFITS

The evaluation of costs and benefits in this study has two basic components:

- **Trade benefits,** which are estimated using energy modeling to obtain the AmerenUE cost to supply its load under each case. The energy market simulation uses General Electric's MAPS tool.

- **Administrative and other related costs**, the AmerenUE costs incurred for administrative charges paid to the Midwest ISO or SPP RTO and to interface with the RTOs, or alternatively to engage an ICT and interface with the ICT.

Detailed energy model simulations were performed for 2009, 2011, 2014 and 2016. Interpolation was used to obtain energy modeling results for intervening years in the study horizon, and the results for the years 2017 and 2018 were projected using the 2016 results.[8]

3. ENERGY MODELING

The energy modeling in this study was performed using General Electric's MAPS tool. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area.

In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. Other than AmerenUE, current RTO membership was assumed to continue in all cases. Aquila Missouri was assumed to remain a transmission owner under the SPP tariff. CRA used its current GE MAPS data base to perform the analysis, as well as its current projection of fuel prices and emission allowance prices. In order to assess the impact of future new entry, CRA used its proprietary National Energy & Environmental Model (NEEM) model to develop a capacity expansion forecast. CRA included currently planned or under construction resources throughout the Eastern Interconnect. Potential CO_2 policies were considered only in a sensitivity analysis. A full description of the GE MAPS inputs is contained in Appendix A.

8 The results for the intervening years were interpolated on a straight-line basis using the MAPS results in 2006 dollars, and then an annual inflation rate of 2.5% was applied.

3.1. MODELING ASSUMPTIONS BY CASE

Seams charges were the primary tool for distinguishing the GE MAPS runs between cases in this study. Seams charges are charges for moving energy from one control area to another in an electric system. In GE MAPS, seams charges are applied on a "per MWh" basis to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. In GE MAPS, seams charges are considered for both commitment and dispatch of generating units; however, the charges between any two areas may be different for commitment than for dispatch.

Both commitment and dispatch seams charges were applied in this study. Commitment seams charges reflect that each control area with the responsibility for reliably committing generating units for operation the next day would have limited ability to rely on external entities for commitment of their resources absent a contractual arrangement. The dispatch seams charges reflect impediments to trade that take place on a real-time basis, including wheeling charges and imperfect knowledge regarding flows outside of the control area.

In this study, for RTOs with day-ahead markets, the unit commitment seams charge was set at zero within the RTO and at $10/MWh between the RTO and adjoining control areas. The commitment seams charge was set at $10/MWh between all other control areas. Dispatch hurdles were set at applicable non-firm off-peak wheeling rates[9] plus a dispatch friction rate. For RTOs with active managed markets, the frictional rate was set at zero for flows within the RTO, and at 3 $/MWh for flows out of the RTO. For flows from all other control areas, the frictional rate was set at 5 $/MWh.

3.1.1. Midwest ISO Modeling

The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights ("FTRs"). In addition, the Midwest ISO has formal plans and budgeting to institute an ancillary services market. The Midwest ISO was modeled in GE MAPS with an ancillary services market in place. The MISO/PJM seams management is assumed to yield a 1 $/MWh reduction in the dispatch seams charge between these two RTOs.

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[9] Based on the current tariff, the AmerenUE out and through rate in the ICT case was set at $1 per MWh. MAPS requires wheeling rates to be rounded to an integer. The current AmerenUE rate is $1.04 per MWH. Based on current tariffs, the non-firm out and through rate for the Midwest ISO was set at $3 per MWh and for the SPP RTO at $2 per MWh. No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

3.1.2. SPP RTO Modeling

The costs and benefits of RTO market development require formal and complex study and consideration. It is anticipated that the SPP will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of this study. For purposes of this study, it is assumed that the SPP RTO market will become similar in overall design to that of the Midwest ISO beginning in 2011.

The SPP RTO commenced operation of a real-time market on February 1, 2007. Prior to 2011, SPP is modeled with the standard $10/MWh commitment seams charges between SPP control areas to model that the SPP commitment is not RTO-wide. Intra-RTO SPP dispatch seams charges are reduced to $1/MWh to take into account the balancing market that is in operation in SPP. Beginning in 2011, the intra-SPP commitment and dispatch seams charges are set to zero as in the Midwest ISO. The current set of FTRs that AmerenUE has in the Midwest ISO was assumed to continue to apply in the SPP case.

3.1.3. ICT Modeling

The ICT case was modeled with the standard $10/MWh commitment and $5/MWh dispatch seams charges between AmerenUE and all adjoining entities, including the SPP RTO, the Midwest ISO, Entergy, AECI, TVA, and MidAmerican. In practice, in an ICT case AmerenUE would not hold FTRs or have separate LMPs for generation and load within the AmerenUE control area. However, for analytic purposes, to maintain consistency across the three cases, AmerenUE generation and load LMPs from GE MAPS were applied in the ICT case to derive trade benefits, and the same set of FTRs as used in the Midwest ISO case were used adjust for congestion between these generation and load LMPs.

Based on the above discussion, the seams charges that were applied to AmerenUE seams are summarized in Table 7. As described above, applicable wheeling charges are also added to the dispatch seams charges (for example, an additional $1/MWh for exports to adjoining regions in the AmerenUE ICT case).

Table 7
Ameren UE Seams Charge Modeled
(before addition of applicable wheeling charges)

With AmerenUE as Member of:	AmerenUE Seams Charges to: Midwest ISO		SPP RTO		Others	
	Commit	Dispatch	Commit	Dispatch	Commit	Dispatch
Midwest ISO	0	0	10	3	10	3
SPP: 2009-2010	10	3	10	1	10	3
SPP: 2011-2018	10	3	0	0	10	3
ICT	10	5	10	5	10	5

4. BENEFITS AND COSTS

4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)

This study assesses the benefits and costs associated with AmerenUE participating in the SPP RTO or an ICT relative to remaining in the Midwest ISO. Welfare for the regulated customers of AmerenUE, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits and costs to the regulated utility are passed through to its native load. If these charges to local area load decrease, regulated customer welfare increases. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation (production) costs.

The major categories of benefits and costs addressed in this study are trade benefits, RTO and ICT administrative costs, and transmission cost allocations. The methodology used to estimate the impact of each major category of benefits and costs is discussed below along with the corresponding results.

4.2. TRADE BENEFITS

The cases analyzed in this study (Midwest ISO, SPP and ICT) reflect varying degrees of impediments to trade between AmerenUE and surrounding regions. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties.

4.2.1. Measurement of AmerenUE Trade Benefits

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the AmerenUE region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales. In turn, AmerenUE's utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates.

Deriving trade benefits for AmerenUE thus requires an analysis of both the production cost of operating the AmerenUE owned generating plants and the associated AmerenUE trading activity. In most studies that evaluate the costs and benefits of a utility joining a RTO, the set of FTRs that would be received by the utility when in the RTO is unknown. However, AmerenUE already has in place a full set of FTRs as an on-going member of the Midwest ISO. This specific set of FTRs is primarily designed to hedge the price differences between AmerenUE load and generators, and was assumed to apply unchanged throughout the study period. The defined set of FTRs allows AmerenUE trade benefits to be measured using LMP injections and withdrawal costs using the following components:

> *(+) Generator Revenues.* Annual AmerenUE generator revenues, computed using hourly LMP at each generator multiplied by the hourly generation at each unit for each case.
>
> *(-) Production Costs.* Annual production cost of the AmerenUE-owned generating units, computed directly from the GE MAPS outputs for each case.
>
> *(-) Load Withdrawal Costs.* Annual AmerenUE load costs, computed by multiplying the hourly AmerenUE load by the hourly AmerenUE load LMP for each case.
>
> *(+) FTR Value.* The annual value of the AmerenUE FTRs, computed using the hourly LMP at the FTR injection and withdrawal points and the quantity of each AmerenUE FTR in each period. The AmerenUE FTRs are assumed to be the same in all three cases.
>
> *(-) Net Operating Reserve Costs.* The MAPS outputs were also used to estimate the spinning and operating reserve costs and revenues that would be received by AmerenUE in the MISO ancillary services market, as well as the SPP ancillary service market assumed to commence in 2011. See Appendix A regarding the ancillary service analysis.
>
> *(+) Marginal Loss Credit.* The Midwest ISO operates by taking into account marginal, rather than average, losses in LMPs. This yields a revenue collection that is ultimately refunded to members. Marginal losses were applied throughout the modeling footprint in MAPS, as the model cannot simultaneously apply average and marginal losses in different regions. As such, a marginal loss credit was calculated

for all three cases by comparing the marginal losses to historical average losses. See Appendix A for further detail.

(+) Capacity Sales. AmerenUE is expected to have capacity in excess of its minimum reserve standard available for sale through 2011. AmerenUE has been making capacity sales into the Midwest ISO market taking advantage of the designation of this capacity as a Midwest ISO resource. The price for this capacity is expected be higher if sold into the Midwest ISO than in the SPP RTO and ICT cases. Capacity prices were estimated for these years in each case. The loss in revenue in the SPP RTO case is estimated to be $3.5 million (2008 present value) over this period, and $9.8 million (2008 present value) in the ICT case.

(+) Net Wheeling Revenue. Through and out wheeling revenue cannot be directly calculated in GE MAPS which models physical, rather than scheduled, flows. For purposes of this study, a separate estimate of AmerenUE through and out wheeling revenue was developed. Based on an analysis of Midwest ISO historical and projected through and out revenue, AmerenUE transmission personnel estimated that AmerenUE would receive $6.5 million in through and out revenue in the Midwest ISO case. Prior to joining the Midwest ISO, AmerenUE through and out revenue was significantly higher, e.g., $16.7 million in 2003 from non-affiliates. Ameren transmission personnel estimated that $12 million in annual through and our revenue for AmerenUE in the ICT case in 2009, and $5.0 million in the SPP case.

The change in each of these trade benefit components in the SPP and ICT case relative to the Midwest ISO case was calculated to determine the total trade benefit impact for these two cases.

4.2.2. Trade Benefit Results

Table 8 shows the components of the trade benefits for the SPP and ICT cases relative to the Midwest ISO case.

Table 8
Trade Benefits in the SPP RTO and ICT Cases
in comparison to Continued Midwest ISO Membership
(in millions of 2008 present value dollars; positive numbers are benefits)

	SPP Case		ICT Case	
	2009-11	**2009-18**	**2009-11**	**2009-18**
Generator Revenue	(8)	172	(62)	75
Production Costs	233	621	296	740
Load Withdrawal Costs	(275)	(891)	(311)	(964)
FTR Value	(23)	(66)	(21)	(63)
Net Operating Reserve Costs	(15)	(44)	(14)	(39)
Marginal Loss Credit	2	3	15	30
Capacity Sales	(4)	(4)	(10)	(10)
Net Wheeling Revenue	(4)	(12)	14	38
Total Trade Benefits	(94)	(221)	(92)	(194)

As shown in Table 8, the significant savings in production costs in the SPP and ICT cases is offset by the large increase in load withdrawal costs. The savings in production costs results from the AmerenUE generating units running less in the SPP and ICT cases, as shown in Table 9.

Table 9
Change in AmerenUE Generation in Comparison to Midwest ISO Case (GWh)

	2009	2011	2014	2016
SPP Case	(3,003)	(2,942)	(2,672)	(2,587)
ICT Case	(4,135)	(3,029)	(2,831)	(2,193)

All else equal, this decrease in generation should result in a significant decrease in AmerenUE generator revenues as well. However, both average generation prices and average load prices increase significantly in the SPP and ICT cases, by roughly similar amounts, as shown in Table 10. These higher generation prices result in AmerenUE generator revenues not decreasing much, or actually increasing, in the SPP and ICT cases despite the lower level of AmerenUE generation. However, this impact is more than offset by the increase in load withdrawal costs at the higher prevailing load price, given that that AmerenUE generation in the SPP and ICT cases declines but AmerenUE load remains the same.

Table 10

Increase in AmerenUE Average Generation Revenue and Average Load Prices in Comparison to Midwest ISO Case ($/MWh, 2007 dollars)

	Gen Revenue Increase				Load Price Increase			
	2009	2011	2014	2016	2009	2011	2014	2016
SPP Case	2.22	2.84	2.84	2.90	1.94	2.87	2.87	2.88
ICT Case	2.53	3.14	2.83	2.76	3.13	4.06	3.62	3.47

The increase in the generation prices relative to load prices in the SPP and ICT cases leads to a negative FTR value for these cases beginning in 2011. In the SPP case, the FTR set likely would be re-optimized by AmerenUE to avoid holding negative value FTRs. All else equal, if the annual value of the FTR set in the SPP case was reset at zero when negative, the value of the SPP trade benefits over the 2009 to 2018 period would increase by $34 million. In the ICT case, as discussed previously, there would not be an actual set of FTRs in practice, nor separate LMPs for AmerenUE generation and load. All else equal, if the annual value of the proxy FTR set in the ICT case was reset at zero when negative, the value of the ICT trade benefits over the 2009 to 2018 period would increase by $33 million. However, some other analytic means would need to be incorporated to equalize the AmerenUE generation and load prices in the ICT case.

The decrease in AmerenUE generation in the SPP and ICT cases could result in trade benefits for the SPP and ICT cases if AmerenUE generation were replaced by lower-cost purchases. However, as shown in Table 11, the AmerenUE trading activity (i.e., the sum of purchases and sales) also declines in the SPP and ICT cases. This decline indicates that the reduction in AmerenUE generation in the SPP and ICT cases is largely foregone off-system sales. In the Midwest ISO case, the average annual AmerenUE operating margin for generation (generator revenue net of production cost) ranges from $17 to $22 per MWh (2007 dollars) over the 2009 to 2018 period in the Midwest ISO case. Foregone off-system sales are thus a key driver in the reduction in trade benefits in the SPP and ICT cases.

Table 11

AmerenUE Trading Activity: Off-System Sales plus Purchases (GWh)

	2009	2011	2014	2016
Midwest ISO Case	9,745	8,423	8,470	8,052
SPP Case	6,895	5,862	6,094	5,672
ICT Case	5,556	4,983	5,125	5,112

4.3. ADMINISTRATIVE AND OTHER COSTS

A number of administrative and other costs must be analyzed in addition to those directly addressed in GE MAPS. The savings in these administrative and other costs of the SPP and ICT cases relative to the Midwest ISO case are summarized in Table 12.

Table 12
Savings in AmerenUE Administrative and Other Costs in the SPP RTO and ICT Cases in Comparison to Continued Midwest ISO Membership
(in millions of 2008 present value dollars; positive numbers are benefits)

	SPP Case		ICT Case	
	2009-11	2009-18	2009-11	2009-18
Savings in Administrative Charges	9.4	(0.9)	29.0	67.4
Savings in RSG and RNU Payments	31.7	31.7	45.6	116.0
Savings in Transmission Cost Allocations	1.1	4.4	6.8	31.1
Loss in Midwest ISO Post-Transition Revenue Distribution	(146.7)	(372.9)	(146.7)	(372.9)
Savings in FERC Charges	-	-	3.8	6.0
One-time Reconfiguration Costs	(4.6)	(4.6)	-	-
Total Savings in Administrative and Other Costs	(109.1)	(342.2)	(61.4)	(152.4)

Each category of costs in Table 12 is discussed in detail in the following sections.

4.3.1. RTO Administrative Charges

Both the Midwest ISO and the SPP RTO incur significant capital and operating costs to operate their markets. These costs are recovered through administrative charges to the RTO members. The Midwest ISO assesses these charges under Schedules 10, 16 and 17 under its tariff. The Midwest ISO projects the charges under these schedules over the 2007 to 2011 period to average about 36 cents per MWh of member load.[10] Of this total, about 13 cents per MWh is for Schedule 10 (ISO Cost Recovery Adder), 2.5 cents is for Schedule 16 (FTR Administrative Service), and 20.5 cents is for Schedule 17 (Energy Markets Support).

AmerenUE's administrative costs in the Midwest ISO over the study period were estimated using Midwest ISO projections of charge rates applied to projections of generation, load and the other billing determinants used to assess the AmerenUE Midwest ISO charges.

SPP RTO charges are expected to be about 20% lower on a cents per MWh basis than those of MISO over the next few years, including operation of the real-time imbalance market, than those of the Midwest ISO. The SPP RTO costs do not yet include any administrative charges for a day-ahead market, financial transmission rights, and an ancillary services market. For the years 2009 and 2010, SPP estimated charges per MWH of energy for load under the current market structure were applied for AmerenUE in the SPP case. These estimated charges per MWH were decreased to take into account the additional economics of scale that SPP estimated that it would incur if AmerenUE were a member.

10 Midwest ISO, Recommended Capital and Operating Budget, Section IV, Projected Average Administrative Cost per MWH, December 14, 2006.

After 2011, the costs of the SPP RTO were assumed to be the same as those in the Midwest ISO. Like the Midwest ISO, the PJM RTO also has day-ahead markets and FTR markets in operation. In 2006, the PJM RTO converted to a system of stated rates that result in projected RTO administrative charges roughly similar to those projected by the Midwest ISO.[11] For purposes of this study, given that the SPP RTO market is assumed to have similar markets and operations to the Midwest ISO beginning in 2011, the projected Midwest ISO administrative charge rates were applied in to SPP RTO case beginning in 2011.

We note that the following of best practices and pressure by RTO members to minimize costs will tend to minimize differences in RTO costs. Even so, potential longer-term cost differences between the two RTOs could result from the following:

- At the present time, the Midwest ISO serves a market load roughly three times larger than that of the SPP RTO. Given economies of scale in RTO operations, this likely favors the Midwest ISO having lower administrative charges per unit of energy for load. Of course, new RTO members and any exiting members could alter this relationship.

- SPP has not yet developed market components beyond a real-time market. This provides additional cost uncertainty for SPP. However, the later development could allow SPP to develop these markets using knowledge and systems gleaned from operations at RTOs with these markets in place. This potentially favors lower development costs for SPP, all else equal.

To estimate AmerenUE ICT costs, publicly available information regarding the administrative costs paid to an ICT by LG&E, MidAmerican Energy, and Entergy were reviewed. The LG&E ICT costs included provision for the ICT to perform all of the standard transmission and reliability functions (from two different ICT vendors) for a cost of approximately $5 million per year. The Entergy ICT costs include the ICT conducting a Weekly Procurement Process for power market that was not considered in this study. Duke Energy performs reliability coordination internally that AmerenUE would have the ICT perform. The MidAmerican ICT costs were not publicly available. As such, the LG&E ICT cost of $5 million per year was assumed to apply to an AmerenUE ICT, increasing at inflation over the study period.

As shown in Table 12, AmerenUE is projected to save $67 million in the ICT case in RTO administrative charges over the 2009 to 2018 period. The Midwest ISO and SPP RTO administrative charges are roughly equivalent over the study period.

11 Settlement Agreement and Offer of Settlement, PJM Interconnection, LLC, FERC Docket No. EL05-1181, April 18, 2006. The PJM stated rates will average 30 to 32 cents per MWh from 2006 to 2011, supplemented by an additional rider for the construction and operation of a second control center.

4.3.2. RNU and RSG Charges

Revenue Sufficiency Guarantee Charges (“RSG”) are designed to recover the payments made to generators to recover their production costs when committed in the day-ahead market or through the Reliability Assessment Commitment process. The RSG payments to committed day-ahead generators are collected from day-ahead load. The RSG payments to committed generators in the Reliability Assessment Commitment process are funded through payments assessed to real-time load deviations from the day-ahead schedule, day-ahead resources not operating as anticipated in real-time, and changes in real-time physical bilateral transactions from the day-ahead market.

Revenue Neutrality Charges (“RNU”) are charges assessed to transactions by the Midwest ISO to cover revenue shortfalls or surpluses, including those that can arise from uplift needed to fund congestion rebates; real-time RSG obligations that are not recovered by the real-time RSG charges; and any revenue inadequacy resulting from the net of all market settlements in each hour.

RSG and RNU costs have been substantial for AmerenUE. AmerenUE’s significant payments for RSG charges resulting from the RSG allocation procedures in the Midwest ISO tariff have been the subject of complaints filed by AmerenUE at FERC in proceedings over the last several years. The Midwest ISO has developed a task force to help address this issue, and some mitigation of the AmerenUE RSG costs through a redesign of the RSG allocation process is included in the figures used in this study. Based on recent historical data, the RNU costs are estimated to be $10.5 million per year, and the net RSG charges are expected to be $7.5 million per year, including a $4 million reduction from historical levels for an expected RSG redesign, for a total of $18 million per year. These costs are held flat in nominal terms over the term of the study given an expectation that control and minimization of these charges will continue to merit attention by the Midwest ISO.

These same RSG and RNU costs are assumed to apply to the SPP RTO case beginning in 2011 when a day-ahead market and FTRs are assumed to be instituted in SPP. These costs would not apply in the ICT case. As shown in Table 12, the net impact is a savings of $32 million in the SPP case relative to the Midwest ISO case over the study period from avoiding these costs in 2009 and 2010. For the ICT case, the savings relative to the Midwest ISO case over the study period are $116 million.

4.3.3. Transmission Cost Allocations

Both the Midwest ISO and SPP have programs in place that would result in a portion of the costs of future transmission investments in the RTO footprint to be allocated to all members of the RTO. In the case of AmerenUE, which has a fairly robust transmission system already in place, the sharing of the costs of RTO-wide transmission investments results in an additional allocation of cost to AmerenUE. That is, the type of transmission investment that would be shared by RTO members is likely to be in parts of the RTO outside of AmerenUE.

AmerenUE transmission personnel estimated the allocation it would receive under the Midwest ISO and SPP RTO current transmission investment plans. In both RTO cases, the costs allocated to AmerenUE start at over $1 million in 2009 and increase to over $7 million by 2018. It was assumed that 5% of this allocation would be shared by Missouri wholesale customers. As shown in Table 12, over the study period, the additional cost allocated to AmerenUE in the SPP RTO case relative to the Midwest ISO case is estimated to be $4.4 million. The ICT case would have no allocation of these costs, and the savings relative to the Midwest ISO case is estimated to be $31.1 million.

4.3.4. Midwest ISO Post-Transition Revenue Distribution

The loss of the post-transition revenue distribution to be received by AmerenUE under continued membership in the Midwest ISO is the significant factor contributing to additional administrative costs in the SPP and ICT cases. The Midwest ISO post-transition period begins in February 2008.

The net post-transition revenue that AmerenUE expects to receive under continued Midwest ISO membership is $57.8 million per year. Over the 2009 to 2018 study period, this yields a present value of $373 million. The revenue would not be received in the SPP and ICT cases, and thus results in an additional cost (i.e., negative benefit) to these cases.

4.3.5. FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for RTO member load-serving utilities are assessed directly to the RTO, and then in turn assessed by the RTO to member companies. Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load. FERC charges for RTO members are therefore higher for non-RTO members.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge to utilities not in an RTO, there will be higher FERC charges to RTO members than non-RTO members, all else being equal.

AmerenUE began paying FERC administrative charges through the Midwest ISO in 2005. For purposes of this study, the difference in the FERC charges between the ICT and RTO cases was estimated by: 1) deriving the historical ratio of AmerenUE FERC charges from 1999 to 2004 to the average expended by neighboring non-RTO members MidAmerican and Entergy Arkansas, 2) multiplying this ratio by the FERC charges expended by MidAmerican and Entergy Arkansas in 2005 and 2006, and 3) comparing this amount to that actually paid by AmerenUE in 2005 and 2006. The analysis indicates that an additional $1.3 million of

FERC administrative charges are paid by AmerenUE when in an RTO. This annual difference was then escalated at inflation over the study period. Given that the FERC rules for assessing this charge could change, this difference was extended only through the first five years of the study period. Using this approach, the savings in FERC fees for AmerenUE in the ICT case relative to the RTO cases is $6.0 million over the study period.

4.3.6. Internal Reconfiguration Costs

AmerenUE has already incurred the development charges necessary to participate in the Midwest ISO. AmerenUE personnel estimated that a one-time $5 million in costs would need to be expended by AmerenUE to develop the internal systems that would be needed to participate in the SPP RTO. This was assumed to take place in 2009 in the SPP RTO case. No further reconfiguration or development expenditures were estimated to be needed for AmerenUE to operate in an ICT environment.

4.4. OVERALL COST-BENEFIT RESULTS

As shown in Table 13, the quantitative findings indicate significant benefits to AmerenUE under continued Midwest ISO membership in comparison to becoming a member of the SPP RTO or contracting with an ICT. The results are presented in terms of the mid-2008 present value of net benefits.

Table 13
Benefits (Costs) to AmerenUE of the SPP RTO and ICT Cases in comparison to Continued Midwest ISO Membership
(in millions of 2008 present value dollars; positive numbers are benefits)

	SPP Case		ICT Case	
	2009-11	2009-18	2009-11	2009-18
Trade Benefits	(94)	(221)	(92)	(194)
Savings in Administrative and Other Charges	(109)	(342)	(61)	(152)
Total Benefits (Costs)	**(203)**	**(563)**	**(153)**	**(346)**

As shown in Table 13, the trade benefits of joining the SPP and ICT cases are negative. That is, the net cost to serve AmerenUE load increases in the SPP and ICT cases relative to continued membership in the Midwest ISO. In addition, the SPP and ICT cases result in increased levels of administrative and other charges. Overall, formation of an ICT is projected to yield a $153 million decrease in net benefits to AmerenUE over the 2009 to 2011 period relative to continued membership in the Midwest ISO, and a $346 million decrease in net benefits over the 10-year study period. SPP RTO membership relative to continued membership in the Midwest ISO is projected to yield a $563 million decrease in net benefits to AmerenUE over the 10-year study period.

4.4.1. Sensitivity Analyses

Six one-year sensitivity analyses were conducted: 1) high fuel prices in 2011, 2) Taum Sauk not return to service being delayed further (the base case assumes a 2011 return), 3) a \$2/MWh higher ICT dispatch seams charge in 2011, 4) a \$2/MWh lower ICT dispatch seams charge in 2011, 5) institution of a carbon tax in 2014, and 6) commercial operation of a second nuclear unit at the Callaway station in 2016.[12] The one-year impact on net benefits of each sensitivity case is shown in Table 14.

Table 14
Increase in One-Year Net Benefits in Sensitivity Analyses
(Nominal dollars)

	SPP Case	ICT Case
High Fuel Price in 2011	(2)	(15)
No Taum Sauk in 2011	7	8
Higher ICT Seams Charge in 2011	NA	(3)
Lower ICT Seams Charge in 2011	NA	3
Carbon Tax in 2014	(86)	(19)
Callaway 2 in 2016	(11)	(1)

As shown, the benefits in the ICT case are reduced with high fuel costs and carbon taxes. The natural gas prices in the base projections decrease from today's levels through 2016 before beginning to increase. To the extent that this decrease in fuel prices does not take place, the ICT case would be at risk for additional costs. The increase (decrease) in the ICT seams charge reduces (increases) ICT case benefits, although not by a large amount. National carbon-control legislation is unlikely to take effect for at least several years in the future, with the exact formulation of that legislation, if any, unknown.

5. QUALITATIVE CONSIDERATIONS

Qualitative considerations, at least in the near term, indicate that a greater level of increased cost risk likely would be faced in the ICT case than in the Midwest ISO case. Qualitative risks that affect the ICT case include:

- The availability, and associated potential cost if available, of transmission to make off-system sales in the ICT case. The quantitative analysis effectively assumes that transmission is available whenever a transaction is economic. In addition, in an ICT

12 If a decision by AmerenUE to proceed with a second unit at Callaway 2 were to take place, the unit would not be in service by 2016. However, as 2016 was the last year modeled in GE MAPS in this study, the unit was placed in service in 2016 to help discern any longer-term impacts that the unit might have on the study results.

case, there is the potential for an additional wheeling charge, not quantified in this study, to move power into the Midwest ISO if the buyer does not have Midwest ISO transmission rights.

- The amount of through and out wheeling revenues that would be received in the ICT case in practice. With a market structure different than that faced by AmerenUE prior to joining the Midwest ISO in 2004, the through and out wheeling revenues that AmerenUE actually would receive in an ICT case (estimated to be $12 million per year) are uncertain.

- The impact of exit fees and hold harmless provisions that could take place if AmerenUE were to exit the Midwest ISO. The exit fees paid by LG&E to exit the Midwest ISO were substantial, and were not considered quantitatively in this study. Along with the exit fees, LG&E also agreed to put in place a number of hold harmless provisions that likely would have an impact on the value of the ICT case if AmerenUE had to institute similar measures.

- The higher fuel case sensitivity worsened the economics of the ICT case, indicating that an unanticipated increase in fuel costs would be harmful to the ICT case economics, all else equal.

- The carbon sensitivity worsened the economics of the ICT case, indicating that the institution of carbon controls could be harmful to the ICT case economics, all else equal.

- The move to an ICT could cause AmerenUE to lose its market-based rate authority in the AmerenUE control area and possibly in other areas. A move to cost-based rates or caps could limit the amount of revenue that AmerenUE could receive from off-system sales.

- The costs in the Midwest ISO case include considerable expenditures for RSG and RNU charges which the Midwest ISO is studying to evaluate how best to reduce these charges in the future.

Risk factors that would work against the Midwest ISO include the potential for AmerenUE's transmission cost allocation to increase substantially in the Midwest ISO case depending on how much new regional transmission is built and how that transmission cost is allocated to AmerenUE. In addition, the Midwest ISO ancillary services market is not yet in place and may result in additional costs (or benefits) than modeled herein. Moreover, the net receipt of Midwest ISO post-transition revenue by AmerenUE under continued Midwest ISO membership is subject to uncertainty related to the treatment of bundled load for other Midwest ISO members.

Finally, RTO control of costs has improved but remains a risk. The Midwest ISO is projecting relatively stable costs in terms of costs per MWh over the next five years. Moreover, the PJM

RTO has moved to a form of stated rates, rather than a direct formula passthrough of all costs. These stated rate are expected be in place through 2011, indicating greater confidence on the part of RTO management in the predictability of costs as RTO markets mature. In addition, FERC has issued reporting rules to allow for greater transparency in evaluating RTO costs. While these trends appear favorable to the stabilization of RTO costs, there continues to be ongoing uncertainty about future RTO market developments and refinements that result in ongoing cost risk to member utilities.

Overall, the cost risk factors for the ICT case appear larger and more uncertain, at least in the near term, than those facing the Midwest ISO case.

6. CONCLUSION

The results of the quantitative analysis show significant benefits to AmerenUE of continued membership in the Midwest ISO. Further review of the ICT and SPP cases in the future may be warranted as market rules and structures evolve and additional information is known about the Midwest ISO ancillary service market, the control of RSG and RNU payments, and the Midwest ISO post-transition revenue distribution to AmerenUE.

7. APPENDIX A: MAPS INPUTS

This appendix summarizes the key inputs to the GE MAPS locational price forecasting model. As formulated for this study, the model's geographic footprint encompasses the U.S. portion of the Eastern Interconnect and the Canadian provinces of Ontario, Manitoba and Saskatchewan with the major focus on the SPP, Midwest ISO and surrounding regions. The GE MAPS simulations focus on the ten-year period from 2009 to 2018. The years directly simulated are 2009, 2011, 2014 and 2016. Results for intervening years are interpolated.

Primary data sources for the model include the NERC MMWG, the General Electric generation and transmission databases for the Eastern Interconnect, various publications by NERC regions and Independent System Operators, FERC submissions by generation and transmission owners, commercial databases from Energy Velocity and CRA in-house analysis of plant operations and market data.

7.1. TRANSMISSION

The CRA model is based on load flow cases provided by the NERC Multiregional Modeling Working Group (MMWG). This analysis uses the modified MMWG 2005 series load flow case for the summer of 2010. The MMWG load flow case encompasses the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. CRA adds to these load flows the Cross-Sound and Neptune high voltage DC cables. Load flow models were further analyzed against regional transmission planning documents and a number of changes were made to the load flow to reflect future transmission projects (those under construction or having a high probability to be implemented, but not included in the original MMWG models). Additional changes to the load flow were made in consultations with Ameren transmission engineers to reflect upgrades within the Ameren control area the company plans to make in the future. The MMWG load flow does not explicitly distinguish AmerenUE from the Central Illinois Power System. That information has been also provided by Ameren personnel as it is essential for the cost-benefit analysis undertaken in this study.

Monitored constraints originate from the following sources:

- The NERC flowgate book (November 2005 version).
- The list of flowgates published by the Midwest ISO on its website.
- A list of flowgates provided by the Southwest Power Pool.
- FERC Form 715 filings, seasonal transmission assessment reports, and studies published by NERC regions and Independent System Operators.
- Regional Transmission Expansion Plan (RTEP) reports published by various ISOs.
- The 2004 Intermediate Area Transmission Review published by the New York ISO.
- Contingency analyses performed by General Electric and by CRA.
- Historically binding constraints monitored by CRA.

For constraints monitored for their thermal limit violations, their limits are updated with respect to each load flow to reflect transmission upgrades. For constraints enforced for stability purposes, we use the limits obtained from the sources above.

Reducing the number of constraints monitored in the study reduces the time required for GE MAPS to solve the optimal commitment and dispatch. Therefore, CRA filters out non-significant constraints far away from the study areas to speed up the process. In this study, all non-duplicate constraints from the above sources within MISO, SPP, non-MISO portion of MAPP and Entergy are included. For other study areas, a constraint is included only if it has been binding in our previous studies, it represents a major interface, or it monitors facilities at 500KV or above.

7.2. Load Inputs

For each load serving entity, GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. CRA uses the latest EIA-411 load forecast data available for each company within the study region. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. If study years are to be modeled after the last year for which forecast data is available, CRA uses linear extrapolation to estimate the peak load and annual energy, by company, for the remaining years.

Load shapes are drawn from hourly actual demand for 2002, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape by company for each forecast year.

7.3. Thermal Unit Characteristics

Description. MAPS models the operational characteristics of generation units in detail to predict hourly dispatch and prices. The following characteristics are modeled:

- Unit type (*e.g.*, steam cycle, combined-cycle, simple cycle, cogeneration)
- Heat rate values and curve (based on unit technology)
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick-start and spinning reserves capabilities
- Startup costs
- Emission rates

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used. Table 15 and Table 16 document these generic assumptions.[13] As is the case throughout this MAPS analysis, all costs are in real 2006 dollars. Capacity and operating characteristics for AmerenUE generating units were verified by Ameren personnel and corrections were made where necessary.

Table 15: Characteristics for Generic Thermal Units

Unit Type & Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Shape
Combined Cycle	$ 2.50	$ 21.00	8	6	2 Blocks, each 50% at FLHR
Combustion Turbine <100 MW	$ 7.00	$ 15.00	1	1	One block
Combustion Turbine >100 MW	$ 7.00	$ 15.00	1	1	One block
Steam Turbine [coal] >200 MW	$ 1.00	$ 35.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <100 MW	$ 3.00	$ 45.00	6	8	
Steam Turbine [coal] <200 MW	$ 3.00	$ 35.00	8	8	
Steam Turbine [gas] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [gas] <200 MW	$ 4.00	$ 30.00	6	10	
Steam Turbine [oil] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [oil] <200 MW	$ 4.00	$ 30.00	6	10	

Table 16: Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Outage Length (Days)
Combined Cycle	-	30%	1.81%	7.40%	3
Combustion Turbine <100 MW	100%	90%	2.81%	5.28%	1
Combustion Turbine >100 MW	100%	90%	2.60%	6.94%	1
Steam Turbine [coal] >200 MW	-	10%	3.07%	9.10%	7
Steam Turbine [coal] <100 MW	-	10%	3.78%	8.32%	3
Steam Turbine [coal] <200 MW	-	10%	4.57%	9.43%	3
Steam Turbine [gas] >200 MW	-	10%	3.50%	14.11%	7
Steam Turbine [gas] <100 MW	-	10%	2.62%	6.81%	2
Steam Turbine [gas] <200 MW	-	10%	3.23%	11.11%	2
Steam Turbine [oil] >200 MW	-	10%	2.79%	13.51%	7
Steam Turbine [oil] <100 MW	-	10%	1.46%	8.33%	2
Steam Turbine [oil] <200 MW	-	10%	3.01%	12.16%	2

Spinning reserve capacity assumptions identified in Table 16 are applied to units that are not operated by companies that are parties to reserve sharing agreements for MISO and SPP.

13 Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include full load heat rates and emissions data.

For SPP and MISO, refer to section 7.11 of this Appendix which provides details on modeling markets of ancillary services in these RTOs.

Data Sources. The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, primary and secondary fuel type, and capacity data for existing units. Heat rate data were drawn from prior ES&D databases where available. For newer plants, heat rates were based on industry averages for the technology of each unit. The NERC Generation Availability Data System (GADS) database published in January 2005 (data through 2003) was the source for forced and planned outage rates, based on plant type, size, and age.

Fixed and variable operation and maintenance costs are estimates based on plant type, size, and age. These estimates are supplemented by FERC Form 1 submissions where available. The fixed operations and maintenance cost (FOM) values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6,000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

7.4. Nuclear Units

Description. CRA assumes that all nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each nuclear unit are drawn from the Energy Central database of unit outages. These plants do not contribute to quick-start or spinning reserves. Refueling and maintenance outages for each nuclear plant are also simulated. Outages posted on the NRC website or announced in the trade press for the near future are included. For later years, refueling outages for each plant are projected based on its refueling cycle, typical outage length, and last known outage dates. Since these facilities are treated as must-run units, CRA does not specifically model their cost structure.

Data Sources. Nuclear unit data were obtained from NRC publications, trade press announcements, and the Energy Central database.

7.5. Hydro Units

Description. MAPS has special provisions for modeling hydro units. For conventional or pondage units, CRA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. CRA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. CRA assumes that the maximum capacity for each hydro unit is flat throughout the year, that the minimum capacity is zero (i.e., that there are no stream-flow or other constraints that force a plant to generate). Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998.

Data Sources. The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database.

7.6. WIND RESOURCES

Description. Individual wind resources were modeled either as zero-cost dispatchable energy resources with high (70%) outage rates or as hourly modifiers based on historical production data. Solar generators are run at 24% annual capacity factor, and restricted to daytime hours.

7.7. CAPACITY ADDITIONS AND RETIREMENTS

The initial set for new entry is based on existing projects in development and on projects with signed interconnection agreements as of December 2006. For study years 2011, 2014 and 2016, CRA added capacity based on economic and/or reliability criteria consistent with the analysis CRA NEEM model analyses performed for Ameren as a part of the AmerenUE IRP process.

Capacity additions are made such that each capacity region complies with its specified reserve margin. Since market regions specified in NEEM are not identical to those used to balance capacity in the MAPS model, capacity additions developed by NEEM and implemented in MAPS for the purpose of this analysis are close but not identical. Future capacity additions used in this analysis are specified in Table 17.

Table 17: New Capacity Additions

Pool	Year	MAPS Name	Full Name	St	Type	ISD	MW	HtRate
ECAR	2007	J K SM08	J K Smith GT 8	KY	GTg	May-07	90	9500
		DRESDNRG	Dresden Energy	OH	CCg	Jul-07	550	7100
		J K SM11	J K Smith GT 11&12	KY	GTg	Dec-07	180	9500
	2008	LIMA	Global Energy Lima	OH	CCg	Jan-08	540	6500
		J K SM09	J K Smith GT 9&10	KY	GTg	May-08	180	9500
		FREMONT	Fremont Energy Center	OH	CCg	Jun-08	645	7100
		WGCRAIN	WGC Rainelle CG	WV	STr	Jul-08	92	10000
	2009	SPURLO04	H L Spurlock 4	KY	STc	Jul-09	278	9500
		SPURLO05	Smith Unit 1	KY	STc	Jul-09	278	9500
	2011	THRBRED1	Thoroughbred Energy 1	KY	STc	Jan-11	790	9500
		TRIMBL02	Trimble County 2	KY	STc	Jan-11	750	9500
	2012	THRBRED2	Thoroughbred Energy 2	KY	STc	Jan-12	790	9500
	2013	CCECAR01	CC ECAR	OH	CCg	Jan-13	500	7100
		GTECAR01	GT ECAR	OH	GTg	Jan-13	250	10000
		GTECAR02	GT ECAR	OH	GTg	Jan-13	250	10000
		GTECAR03	GT ECAR	OH	GTg	Jan-13	250	10000
		STECAR01	STc ECAR	OH	STc	Jan-13	750	9500
	2014	CCECAR02	CC ECAR	OH	CCg	Jan-14	500	7100
		CCECAR03	CC ECAR	OH	CCg	Jan-14	500	7100
		GTECAR04	GT ECAR	OH	GTg	Jan-14	250	10000
		GTECAR05	GT ECAR	OH	GTg	Jan-14	250	10000
		GTECAR06	GT ECAR	OH	GTg	Jan-14	250	10000
		GTECAR07	GT ECAR	OH	GTg	Jan-14	250	10000
		GTECAR08	GT ECAR	OH	GTg	Jan-14	250	10000
	2015	CCECAR04	CC ECAR	OH	CCg	Jan-15	500	7100
		CCECAR05	CC ECAR	OH	CCg	Jan-15	500	7100
		GTECAR09	GT ECAR	OH	GTg	Jan-15	250	10000
		GTECAR10	GT ECAR	OH	GTg	Jan-15	250	10000
		GTECAR11	GT ECAR	OH	GTg	Jan-15	250	10000
	2015	GTECAR12	GT ECAR	OH	GTg	Jan-15	250	10000
		GTECAR13	GT ECAR	OH	GTg	Jan-15	250	10000
		GTECAR14	GT ECAR	OH	GTg	Jan-15	250	10000
	2016	CCECAR06	CC ECAR	OH	CCg	Jan-16	500	7100
		GTECAR16	GT ECAR	VA	GTg	Jan-16	250	10000
		GTECAR17	GT ECAR	MI	GTg	Jan-16	250	10000
		STECAR02	STc ECAR	OH	STc	Jan-16	750	9500
		STECAR03	STc ECAR	OH	STc	Jan-16	750	9500
ENTGY	2007	DELL	TECO Dell	MS	CCg	Apr-07	599	7100
	2010	PLUMPNT	Plum Point (LS Power)	AR	STc	Jan-10	665	9500

Pool	Year	MAPS Name	Full Name	St	Type	ISD	MW	HtRate
MAIN	2008	PTWASHC2	Port Washington CC 2	WI	CCg	Jul-08	500	7100
		WESTON04	Weston 4	WI	STc	Jul-08	500	9000
	2009	OAKCREEK	Elm Road 1	WI	STc	May-09	615	9000
		DALLMA04	Dallman 4	IL	STc	Aug-09	200	9000
	2010	OAKCREK2	Elm Road 2	WI	STc	May-10	615	9000
	2011	PRSTATE1	Prairie State Energy 1	IL	STc	Jan-11	790	9500
	2012	CCMAIN01	CC MAIN	IL	CCg	Jan-12	500	6900
	2012	PRSTATE2	Prairie State Energy 2	IL	STc	Jan-12	790	9500
	2013	CCMAIN03	CC MAIN	IL	CCg	Jan-13	500	6900
		GTMAIN01	GT MAIN	IL	GTg	Jan-13	250	10000
		GTMAIN02	GT MAIN	IL	GTg	Jan-13	250	10000
	2014	CCMAIN02	CC MAIN	IL	CCg	Jan-14	500	6900
		GTMAIN03	GT MAIN	IL	GTg	Jan-14	250	10000
		GTMAIN04	GT MAIN	IL	GTg	Jan-14	250	10000
		GTMAIN05	GT MAIN	IL	GTg	Jan-14	250	10000
	2015	CCMAIN04	CC MAIN	IL	CCg	Jan-15	500	6900
		GTMAIN06	GT MAIN	IL	GTg	Jan-15	250	10000
		STMAIN01	STc MAIN	IL	STc	Jan-15	750	9500
	2016	CCMAIN07	CC MAIN	WI	CCg	Jan-16	500	6900
		GTMAIN07	GT MAIN	IL	GTg	Jan-16	250	10000
		GTMAIN08	GT MAIN	IL	GTg	Jan-16	250	10000
		GTMAIN09	GT MAIN	IL	GTg	Jan-16	250	10000
MAPP	2007	CAMBRICT	Cambridge New CT	MN	GTg	Jan-07	155	10800
		FIBROBIO	Fibrominn Bio Plant	MN	STr	Mar-07	50	10000
		EXIRA3	Exira Peaker 3	IA	GTg	May-07	40	11000
		COUNCNW	Council Bluffs 4	IA	STc	Aug-07	790	8500
		FARIBLT2	Faribault Energy Park CC	MN	CCgo	Sep-07	255	7100
	2008	HIGH BCC	High Bridge CC	MN	CCg	Jun-08	610	7100
	2009	NEBRAS02	Nebraska City Station 2	NE	STc	May-09	663	9500
		RIVERSCC	Riverside CC	MN	CCg	Jul-09	400	7100
	2011	BIG ST02	Big Stone 2	SD	STc	Jan-11	600	9500
	2012	GTMAPP01	GT MAPP	ND	GTg	Jan-12	250	10000
	2013	STMAPP01	STc MAPP	ND	STc	Jan-13	750	9500
	2014	CCMAPP01	CC MAPP	ND	CCg	Jan-14	500	6900
	2015	STMAPP02	STc MAPP	ND	STc	Jan-15	750	9500
	2016	STMAPP03	STc MAPP	ND	STc	Jan-16	750	9500
SPP	2007	RIVERT12	Riverton 12	KS	GTg	Apr-07	155	11500
	2008	RIVERSG1	Riverside GT1	OK	GTg	Jul-08	80	12000
		RIVERSG2	Riverside GT2	OK	GTg	Jul-08	80	12000
	2009	RODEMA05	Rodemacher 5	LA	STc	Jun-09	600	9500
	2010	IATAN 02	Iatan 2	MO	STc	Jun-10	850	9500
		SOUTHWF2	Southwest Power St. ST2	MO	STcg	Oct-10	300	9500

Other information from NEEM that is used in MAPS includes: coal choices, delivered coal prices, emission rates for SO_2, NO_X and Hg, allowance prices for SO_2, NO_X and Hg, and unit retirements. NEEM is a process-based model of national US electricity markets (with limited representation of Canada as well). Electricity markets are divided into 27 individual demand regions (based on NERC sub-regions) and interconnected by limited transmission capabilities (also based on NERC data). Units are dispatched to load duration curves within each region so that all loads are met at least cost. Every existing generating unit in the US is represented in the model, with its current emissions control equipment. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all regional and national, seasonal and annual emissions caps for SO_2, NO_X and Hg (and CO_2 if relevant). NEEM has been widely used within the electric sector to analyze the costs, impacts, and allowance prices of multi-pollutant proposals.

The capacity expansion did not vary by case in this study. According to the NEEM results, no capacity was retired in the SPP region during the study period. Taking into account already planned generating additions, no additional capacity was added in the NEEM modeling in this region. The NEEM modeling is designed to provide a consistent basis for estimating capacity expansion throughout the Eastern Interconnect. By necessity, the capacity expansion in the NEEM analyses is a projection based upon generalized input assumptions and will vary from actual future experience, including the size, type and location of specific new units.

7.8. ENVIRONMENTAL REGULATIONS

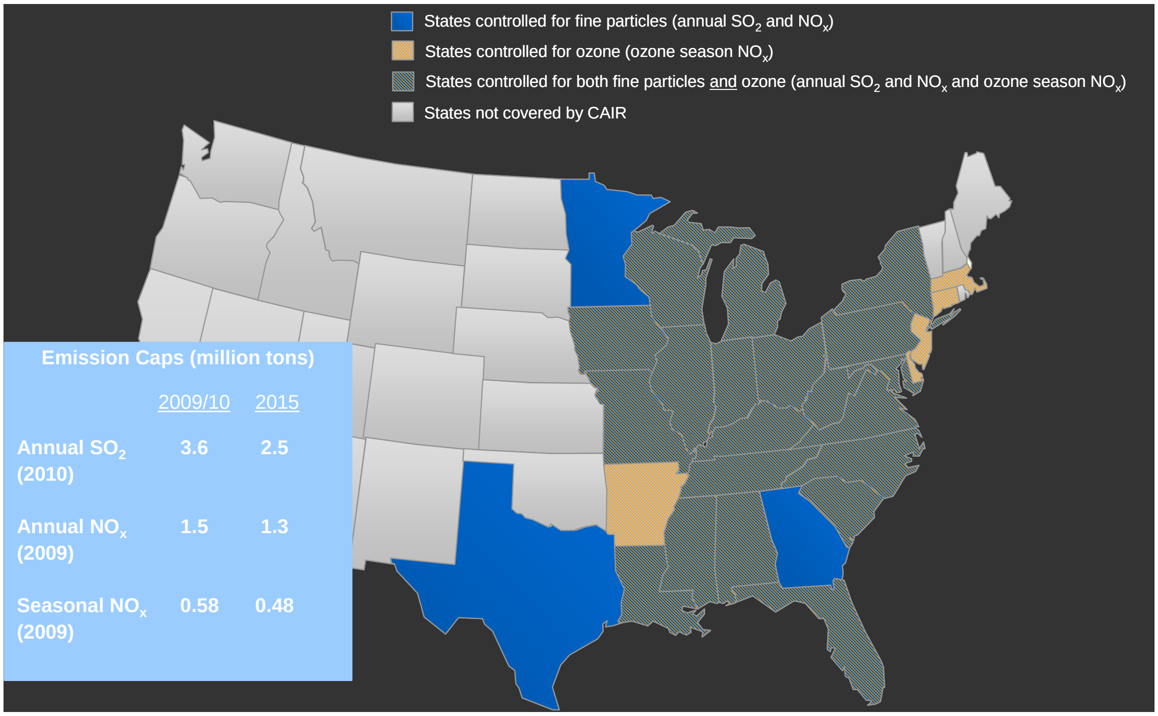
Description. For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation.

CRA models NO_x and SO_2 emission rates for all units where such data is available. In addition, CRA models compliance with various allowance trading programs, and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the US Environmental Protection Agency. Emission rates for NO_x and SO_2 are obtained from industry futures, in particular those published by the Cantor Environmental Brokerage.

CRA used its in-house NEEM model to forecast NO_x and SO_2 permit prices in the long run following the Clean Air Interstate Rules (CAIR) issued by EPA in March 2005. Implications of CAIR rules vary geographically as shown in Figure 1.

Figure 1. Geography of CAIR rules



Source: EPA

The forecast of emission allowance prices for NO_x and SO_2 are presented in Table 18. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

Table 18: Forecast Emission Allowance Prices

	Non-CAIR SO2 ($/Ton)	CAIR SO2 ($/Ton)	NOx ($/Ton)
2009	810	810	1613
2011	425	851	1694
2014	480	961	1698
2016	389	1112	1965

***Data Sources**.* The EPA's Clean Air Markets Emissions Scorecard provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. Allowance price forecasts are developed by CRA using the NEEM Model.

7.9. External Region Supply

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian provinces of Ontario, Manitoba and Saskatchewan. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. These heat rates are multiplied by the appropriate forecast gas price in each scenario, to arrive at a price points for each DC tie. The tie is then modeled as follows:

- When the locational price at the DC tie is within ± $2.50/MWh of the corresponding price point, zero flow is assumed on the tie.
- At locational prices that are between $2.50/MWh and $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at full capacity.
- At locational prices that are between $2.50/MWh and $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at full capacity.

7.10. DISPATCHABLE DEMAND (INTERRUPTIBLE LOAD)

Description. The presence of demand response is important to the energy and installed capacity markets. The value of energy to interruptible load caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. For this study, the size of interruptible load is determined as a percentage of total load, based on Interruptible Demand and Direct Control Load Management as reported in the EIA-411 data. The dispatchable demand for each load area is modeled as a generator with a dispatch price of $600/MWh for the first block (50% of the area’s dispatchable demand) and $800/MWh for the second block. These proxy units rarely run in the model, because the high prices they require indicate a supply shortfall and prompt new entry. Thus they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

Data Sources. Data were drawn from the EIA-411 report data.

7.11. Market Model Assumptions

Marginal Cost Bidding. All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel variable O&M plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

Operating Reserves Requirement (spinning and standby). Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled.

In modeling markets for operating reserves different modeling techniques were applied to the area of interest, the MISO and SPP footprints, including AmerenUE, and to the rest of the system.

For the area of interest, requirements for spinning plus automatic generation control (AGC) and quick start reserves are treated separately as two types of constraints than need to be met simultaneously with the requirement to balance generation and loads. GE MAPS is used to co-optimize commitment and dispatch for meeting spinning plus AGC requirements and quick start requirements. Requirements for spinning and AGC are combined and are set to be equal to 150% of spinning reserve requirements. Meeting this requirement is modeled through the operating reserve co-optimization logic embedded in GE MAPS. Quick start requirements are added to the model in the form of nomograms which prevent the required level of quick start capacity from being dispatched for energy.

Table 19 shows spinning reserve requirements specified by scenario. As noted above, prior to becoming an input to GE MAPS, these numbers are then increased by a factor of 1.5 to also reflect the needs for AGC.

Table 20 presents quick-start requirements for different parts of the area of interest under different scenarios. It is important to note that in modeling the Midwest ISO market for operating reserves, we assumed that the reserve requirements were met by all members of the Midwest ISO Reserve Sharing Group (RSG). RSG companies that are not market members of the Midwest ISO were required to provide their portions of reserves on a company-by-company basis. The remainder of the Midwest ISO reserve requirements was met by active Midwest ISO members on a pool basis. For scenarios in which AmerenUE was assumed to be a member of SPP, AmerenUE's portion of operating reserve requirements was re-allocated among other members of the RSG on a pro-rata bases. For scenarios in which AmerenUE was assumed to contract with an ICT, we assumed that AmerenUE would continue to be a member of the MISO RSG, but would not participate in the MISO market for operating reserves. SPP requirements for operating reserves were set at 100% of the first largest contingency plus 50% of the second largest contingency. This assumption was used in all scenarios. Depending on whether AmerenUE was modeled as an SPP member or not, SPP reserve requirements were recalculated accordingly.

In modeling supply for operating reserves within the area of interest, the spinning and quick start capabilities of generating units were specified on a unit type basis. For spinning reserves, the maximum level of spinning reserve capability of a thermal unit was set at the lesser of the units ramp rate (in MW/min) times ten and its capacity above minimum block. Assumed ramp rates are: 10 MW/min for combined cycle units, 6 MW/min for gas and oil turbines, and 3 MW/min for coal units. For hydro plants, spinning reserve capability was set on a monthly basis at 50% of the difference between the plant's capacity in that month and its average hourly output for that month. No spinning capability was assigned to nuclear generators. For AmerenUE units, specific unit-by-unit spinning reserves capabilities were provided by Ameren. For the purpose of this study we assumed that only internal combustion generating units are quick start capable.

Operating reserve requirement for markets outside of the area of interest were not differentiated between spinning reserves and quick start. Instead, consistent with the embedded GE MAPS logic, total reserve requirements and the portion of those requirements which must be met by spin were specified as shown in Table 21. AGC requirements in these markets were not considered. Spinning and quick start capabilities for these markets are specified in Table 16 above.

Table 19: Spinning Reserve Requirements for AmerenUE, MISO and SPP

Market	MISO	SPP	ICT
2009			
AmerenUE	In MISO	43 MW	43 MW
MISO	631 MW	631 MW	588 MW
SPP	873 MW	845 MW	873 MW
2011 and beyond			
AmerenUE	In MISO	In SPP	43 MW
MISO	631 MW	631 MW	588 MW
SPP	873 MW	888 MW	873 MW

Table 20: Quick Start Reserve Requirements for AmerenUE, MISO and SPP

Market	MISO	SPP	ICT
2009			
AmerenUE	In MISO	63 MW	63 MW
MISO	947 MW	947 MW	884 MW
SPP	873 MW	845 MW	873 MW
2011 and beyond			
AmerenUE	In MISO	In SPP	43 MW
MISO	947 MW	947 MW	884 MW
SPP	873 MW	888 MW	873 MW

Table 21: Operating Reserve Requirements for Other Markets

ISO/Region	Operating Reserve	Met by Spin
ISO-NE	1,900 MW	67%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
PJM	4,500 MW	67%
Entergy	4% of load	65%
Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	1,600 MW	55%

Transmission Losses. Transmission losses are modeled at marginal rates over the entire Eastern Interconnection. The Midwest ISO operates by taking into account marginal, rather than average, losses in LMPs. This yields a revenue collection that is ultimately refunded to members. Marginal losses were applied throughout the modeling footprint in MAPS, as the model cannot simultaneously apply average and marginal losses in different regions. As such, a marginal loss credit was calculated for all three cases by comparing the marginal losses to historical average losses.

Marginal pricing of transmission losses results in a revenue surplus being collected by the RTO. This revenue surplus is then reallocated and credited back to market participants. The origin of this revenue surplus is a non-linear relationship between the level of losses and the flow of power through the grid. Due to this non-linear relationship, marginal losses (incremental power loss in the grid in response to an incremental power flow) are greater than average losses caused by the underlying flow.

In each hour, the allocated revenue surplus is computed using the following formula:

$$CR(h) = L(h) \times LMP_L(h) \times [MLoss(h) - AvLoss]$$

where

$CR(h)$ is marginal loss credit in hour *h*;

$L(h)$ is AmerenUE load in hour *h*

$LMP_L(h)$ -- AmerenUE load LMP in hour *h*

$MLoss(h)$ -- AmerenUE marginal loss factor in hour *h*

$AvLoss$ -- AmrerenUE average loss factor. In consultation with AmerenUE, this factor was set to equal 1.8% for the MISO and SPP scenarios and 1.5% for the ICT scenario. The 1.8% value is based on the marginal loss credit AmerenUE currently receives from MISO. The

1.5% value applied to the ICT scenario is based on an analysis of transmission losses within the AmerenUE system conducted by Ameren's transmission engineers.

The AmerenUE marginal loss factor is computed hourly based on GE MAPS simulation results according to the following formula

$$MLoss(h) = \frac{LMPLoss_{Load}(h)}{LMPEn(h)} - \frac{\sum_k G_k(h) \times LMPLoss_k(h)}{LMPEn(h) \times \sum_k G_k(h)}$$

Where:

$G_k(h)$ - generation output of AmerenUE unit K in hour h;

$LMPLoss_k(h)$ - loss component of LMP at the unit k location in hour h

$LMPEn(h)$ - energy component of LMP, i.e. price at the reference bus in hour h

$LMPLoss_{Load}(h)$ - loss component of LMP at the AmerenUE load in hour h

7.12. Seams Charges

Seams charges are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, seams charges are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Seams charges are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch.

Both commitment and dispatch seams charges were applied in this study. For RTOs with day-ahead markets, the unit commitment seams charge was set at zero within the RTO and at $10/MWh between the RTO and adjoining control areas. The commitment seams charge was set at $10/MWh between all other control areas. Dispatch hurdles were set at applicable non-firm off-peak wheeling rates[14] plus a dispatch friction rate. For RTOs with active

[14] Based on the current tariff, the AmerenUE out and through rate in the ICT case was set at $1 per MWh. GE MAPS requires wheeling rates to be rounded to an integer. The current AmerenUE rate is $1.04 per MWH. Based on current tariffs, the non-firm out and through rate for the Midwest ISO was set at $3 per MWh and for the SPP RTO at $2 per MWh. No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

managed markets, the frictional rate was set at zero for flows within the RTO, and at 3 $/MWh for flows out of the RTO. For flows from all other control areas, the frictional rate was set at 5 $/MWh.

The MISO/PJM seams management is assumed to yield a 1 $/MWh reduction in the dispatch seams charge between these two RTOs. Prior to 2011, SPP is modeled with the standard $10/MWh commitment seams charges between SPP control areas to model that the SPP commitment is not RTO-wide. Intra-RTO SPP dispatch seams charges are reduced to $1/MWh to take into account the balancing market that is in operation in SPP. Beginning in 2011, the intra-SPP commitment and dispatch seams charges are set to zero as in the Midwest ISO.

Table 22 gives an overview of the wheeling rates between SPP, MISO, AmerenUE and other neighboring control areas for all scenarios.

Table 22: Seams Charges for SPP, Midwest ISO and AmerenUE by Scenario

			Dispatch Seams Charge		
From	To	Commitment Seams Charge	Wheeling Off-peak	Friction*	Total
MISO	SPP	10	3	3	6
MISO	PJM	10	0	2	2
MISO	AmUE ICT	10	3	3	6
MISO	All Other	10	3	3	6
PJM	MISO	10	0	2	2
PJM	Other	10	2	3	5
SPP 09	MISO	10	2	5	7
SPP 09	AmUE ICT	10	2	5	7
SPP 09	All Other	10	2	5	7
SPP 09	SPP 09	10	0	1	1
SPP 11	SPP 11	0	0	0	0
SPP 11	MISO	10	2	3	5
SPP 11	AmUE ICT	10	2	3	5
SPP 11	All Other	10	2	3	5
AmUE ICT	All	10	1	5	6
LG&E	All	10	1	5	6
Entergy	All	10	2	5	7
AECI	All	10	2	5	7
TVA	All	10	2	5	7
MEC	All	10	3	5	8
All Other	All Other	10	2	5	7

Dispatch
* $3 dispatch friction hurdle for flows out of active managed markets
* Non market areas not expected to be as efficient hence higher dispatch friction hurdle of $5
* Non-firm off peak hourly rate used in addition to friction
* SPP 09 intra-pool dispatch friction set at $1 given balancing market
* PJM to/from MISO friction set at $2 given extensive seams management process

7.13. FUEL PRICES

Description. MAPS requires monthly fuel prices for each generating unit in the model footprint. The fundamental assumption concerning participant behavior in competitive energy markets is that generators will bid their marginal cost into the energy market, including the marginal cost of fuel, variable operations and maintenance (O&M) and the costs associated with marginal emission of pollutants. The marginal cost of fuel is defined as either the opportunity cost of fuel purchased or the spot price of fuel at a location representative of the plant. If the fuel is purchased on a long term contract, it assumed that the opportunity cost of the fuel is the same as the price of fuel on the locational spot market.

CRA uses forecasts of spot prices at regional hubs, and refines these prices on the basis of historical differentials between price points and their associated hubs. For fuel oil and coal, CRA uses estimates of the delivered price of fuel to generators on a regional basis. Dual-fuel generators are simulated as follows:

Natural Gas Primary. Units that primarily burn natural gas may burn fuel oil in at most one month of the year. Because natural gas prices are typically highest in January, the model allows the unit to switch to fuel oil for January if the oil price at that location is lower than the natural gas price.

Fuel Oil Primary. Units that primarily burn oil may switch to natural gas whenever it is economically justified. CRA assumes that natural gas shortages prevent this from happening in the winter heating period, defined as November though March. A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched to natural gas during April through October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are forecast on a unit-by-unit basis by the CRA NEEM model. Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Specific oil and gas price forecasts used in this study are provided in the next section.

7.14. NATURAL GAS AND FUEL OIL PRICE FORECAST

7.14.1. Natural Gas Forecast

Principal Drivers: The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of the closing of May 7, 2007. For 2016 through 2025, CRA uses the EIA Annual Energy Outlook (AEO2007) Reference Case forecast. Prices for 2013 through 2015 are interpolated. The CRA Base Case forecast for natural gas prices at Henry Hub is shown in Figure 2.

Regional Prices: CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. In the near term (through 2011), the basis forecast is derived from NYMEX Clearport hub futures settlement as of May 7, 2007. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives summer and winter differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

Local Delivery Charges: Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies. CRA estimates this local component at $0.07/MMBtu for all units. For older units CRA estimates extra LDC charges derived from AGA statistics.

Seasonal Pattern: Natural gas prices are varied seasonally based on NYMEX futures data in the near term (through 2012). Beyond 2012, the seasonal pattern shown in 2012 is repeated for each year.

Figure 3 compares the Base Case gas price forecast by region.

Figure 2. Henry Hub Prices, History and Forecast (in real 2006 $/MMBtu)

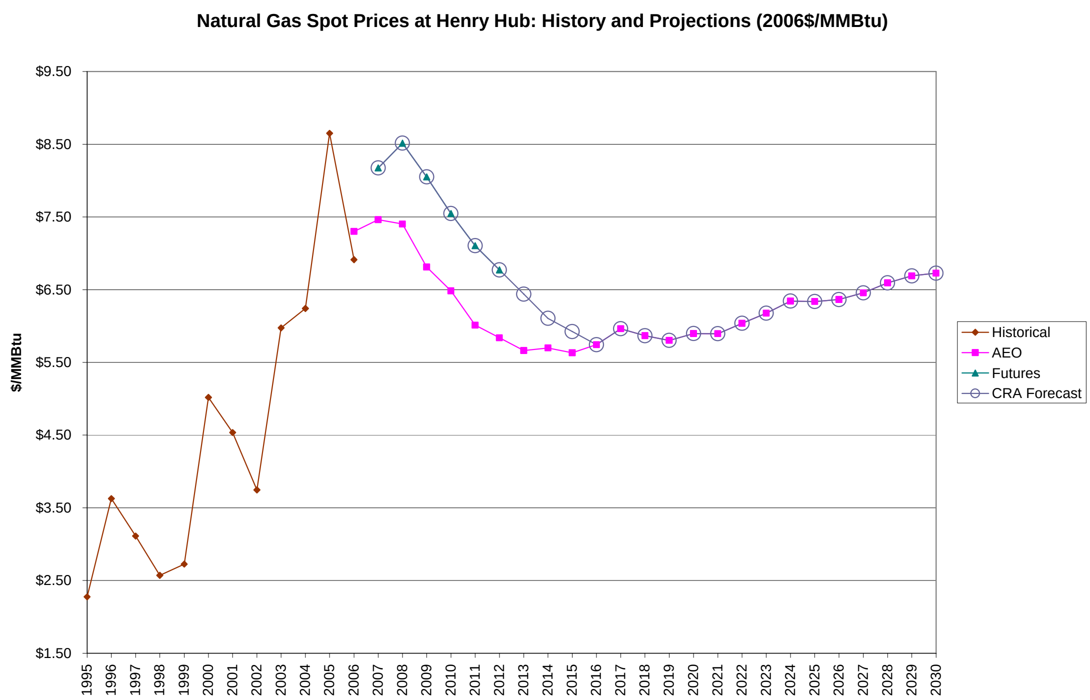
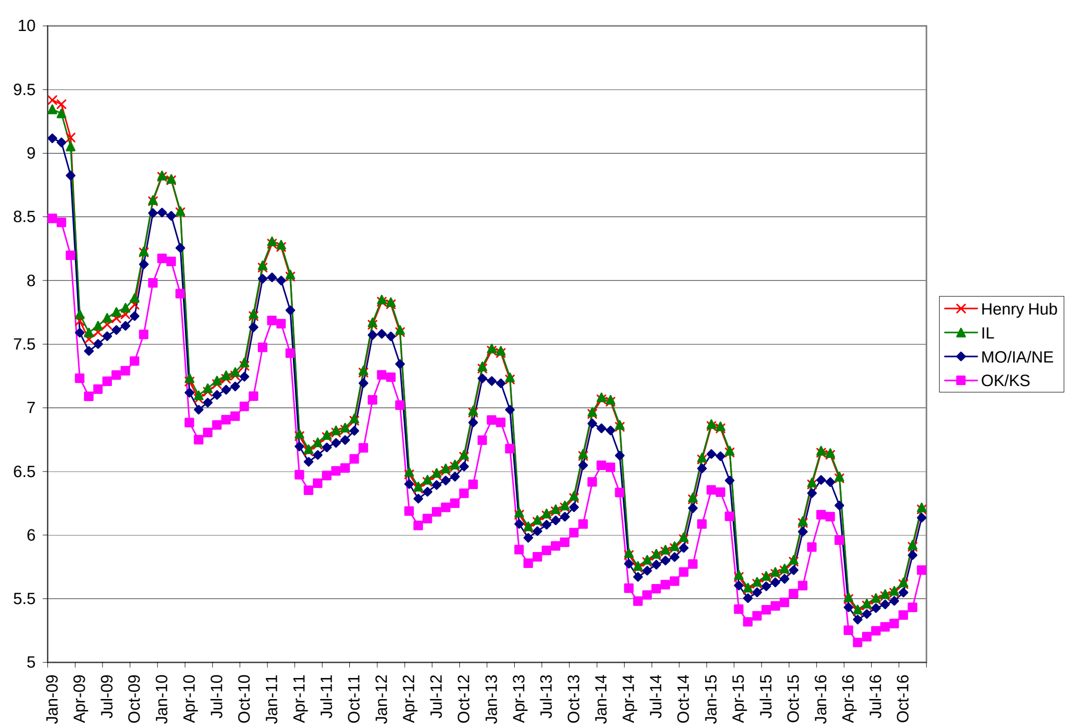


Figure 3. Forecast Regional Natural Gas Prices (Real 2006 $/MMBtu)



7.14.2. Fuel Oil Price Forecast

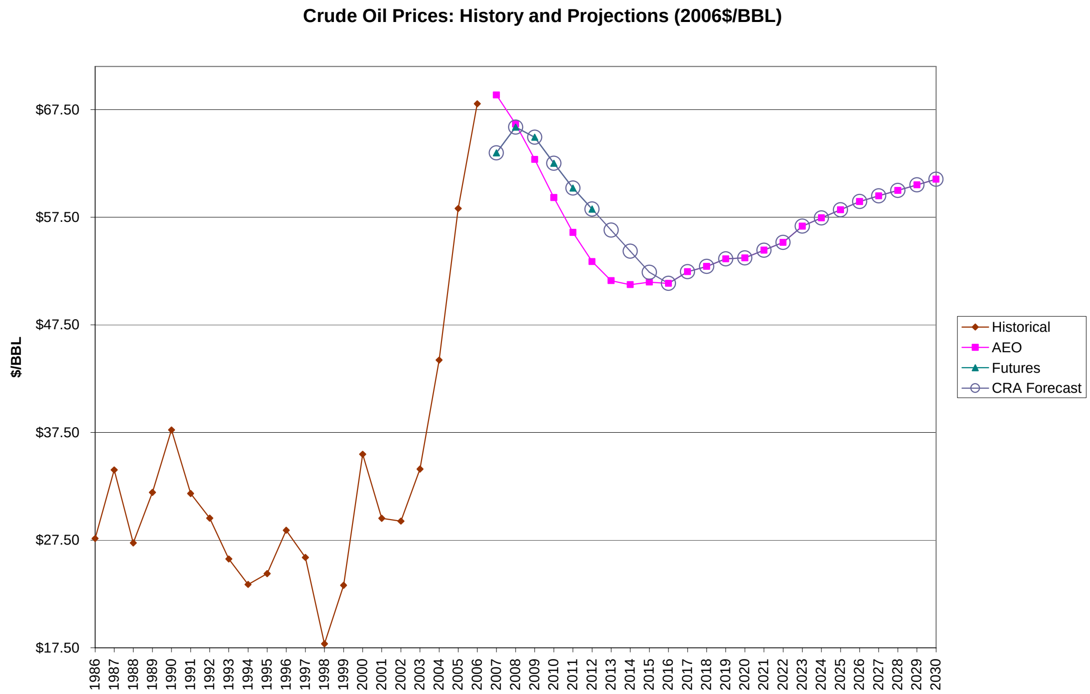
Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is derived from the NYMEX futures prices for light sweet crude oil as of the closing of May 7, 2007. For 2013, 2014 and 2015 the forecast is an interpolation between the futures and the AEO2007. Through 2030, CRA uses the AEO2007 Reference Case forecast. CRA Base Case forecast for light sweet crude oil is presented in Figure 4.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in three steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. Second, New York Harbor prices (both fuel oil #2 and fuel oil #6) are linked to the AEO Reference Case forecast of US average prices of each type of fuel oil used by electric utilities. This derivation is also based on historical regression. Finally, CRA uses AEO forecast to develop yearly regional multipliers linking national average prices and prices by census region. Petroleum Business Tax of $0.45/MMBtu for fuel oil #6 and $0.63/MMBtu for fuel oil #2 is added to oil prices for New York State.

Seasonal Pattern: Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term, and based on historical monthly patterns in the longer term.

Figure 4. Crude Oil Prices: History and Projection (Real 2006 $/BBL)



7.15. Sensitivity Assumptions

Six one-year sensitivity analyses were conducted: 1) high fuel prices in 2011, 2) Taum Sauk's return to service being delayed further (the base case assumes a 2011 return), 3) a $2/MWh increase in the ICT seams charge in 2011; 4) a $2/MWh decrease in the ICT seams charge in 2011; 5) institution of a carbon tax in 2014, and 6) commercial operation of a second nuclear unit at the Callaway station in 2016.

2011 High Fuel Price Sensitivity:

Under this sensitivity, forecasted natural gas prices at Henry Hub, crude oil prices and delivered coal prices in 2011 were increased by 20% from the base case level. Delivered natural gas prices and fuel oil prices were then derived using the methodology described in the previous section. All other input assumptions remained the same as in the base case.

2011 Taum Sauk sensitivity

Under this sensitivity, CRA assumed that Taum Sauk would not be in service in 2011. All other input assumptions remained the same as in the base case.

2011 ICT Seams Charge sensitivities

In these sensitivity cases, the dispatch seams charge from the AmerenUE ICT to adjoining regions was increased by $2/MWh and decreased by $2/MWh in 2011. The dispatch seams charge from the AmerenUE ICT to adjoining regions in the ICT base case is $6/MWh, including the applicable AmerenUE wheeling rate.

2014 Carbon Tax sensitivity

Under this sensitivity, GE MAPS inputs for 2014 were modified based on the Carbon Tax scenario generated by NEEM for the Ameren IRP study. Revised GE MAPS inputs under this scenario include emission allowance prices, electricity demand, delivered coal prices, coal plants retrofit forecast, and new build forecast.

Table 23 below specifies revised emission allowance prices in comparison to the base case. Forecast electricity demand under this sensitivity is lower than in the base case by as little as 0.6% and as much as 1.75% depending on the region. AmerenUE demand is reduced by 1.36%.

Table 23: Forecast Emission Allowance Prices under Carbon Tax Scenario

	Non-CAIR SO2 ($/Ton)	CAIR SO2 ($/Ton)	NOx ($/Ton)	CO2 ($/Ton)
2014 Base	480	961	1698	0
2014 Carbon	398	796	1530	15.0

2016 Callaway 2 sensitivity

This sensitivity models the impact of adding a 1600 MW Callaway 2 nuclear facility. To accommodate this addition, a set of upgrades will be required to the transmission system. Changes to the transmission topology were provided by Ameren. CRA implemented them in the load flow model and re-solved the load flow using the PowerWorld simulator. The updated load flow was used as an input to GE MAPS simulations. Other than inclusion of the additional unit, and the associated transmission upgrades, no other input parameters were modified.

8. APPENDIX B: SUPPORTING DETAIL

8.1. ANNUAL RESULTS

8.1.1. SPP Case

The projected annual benefits (costs) to AmerenUE of being a member of the SPP RTO in comparison to continued membership in the Midwest ISO are summarized in Table 24.

Table 24
Annual Benefits (Costs) to AmerenUE of the SPP Case in comparison to the Midwest ISO Case
(in millions of dollars; positive numbers are benefits)

		Present Value	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	*2009-11 Present Value*
	AmerenUE in SPP RTO												
+	Production Cost Savings	**620.9**	85.3	92.3	99.5	97.9	96.3	94.5	97.8	101.3	103.8	106.4	*233.2*
+	Generator Revenue Increases	**171.4**	(21.7)	(2.3)	18.0	26.3	34.9	44.0	51.0	58.3	59.8	61.2	*(7.9)*
+	Load Withdrawal Savings	**(890.8)**	(84.4)	(109.6)	(135.9)	(141.5)	(147.3)	(153.2)	(160.1)	(167.2)	(171.3)	(175.6)	*(275.2)*
+	FTR Value Increases	**(66.0)**	(6.7)	(9.3)	(12.0)	(11.3)	(10.6)	(9.8)	(10.5)	(11.2)	(11.5)	(11.8)	*(23.3)*
+	Net Operating Reserve Savings	**(43.6)**	(3.0)	(5.9)	(8.9)	(8.5)	(8.1)	(7.7)	(7.0)	(6.4)	(6.6)	(6.7)	*(14.7)*
+	Marginal Loss Credit Increases	**2.6**	0.6	0.6	0.6	0.5	0.4	0.3	0.2	0.0	0.0	0.0	*1.6*
+	Capacity Sales	**(3.5)**	(1.2)	(1.8)	(1.2)								*(3.5)*
+	Net Wheeling Rev Increases	**(11.8)**	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.9)	(1.9)	(2.0)	(2.0)	(2.1)	*(4.3)*
=	Trade Benefits	**(221.0)**	(32.7)	(37.7)	(41.7)	(38.4)	(36.1)	(33.8)	(30.6)	(27.2)	(27.9)	(28.5)	*(94.2)*
+	Admin Charge Savings	**(0.9)**	6.0	5.8	(1.4)	(1.4)	(1.4)	(3.4)	(3.3)	(3.1)	(3.2)	(3.3)	*9.4*
+	RSG and RNU Cost Savings	**31.7**	18.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*31.7*
+	1-Time Reconfiguration	**(4.6)**	(5.0)										*(4.6)*
+	Transm Cost Allocation Savings	**4.4**	(0.2)	(0.2)	1.9	2.4	0.8	1.2	(0.1)	0.3	0.3	0.2	*1.1*
+	Addtl Transm Reservations	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
+	MISO Post-Trans Rev Distribution	**(372.9)**	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	*(146.7)*
+	FERC Charge Savings	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
=	Subtotal Other Charges	**(342.2)**	(39.0)	(34.2)	(57.4)	(56.8)	(58.4)	(60.0)	(61.2)	(60.7)	(60.8)	(60.9)	*(109.1)*
	Total	**(563.2)**	(71.8)	(71.9)	(99.1)	(95.2)	(94.6)	(93.8)	(91.8)	(87.8)	(88.6)	(89.4)	*(203.3)*

8.1.2. ICT Case

The projected annual benefits (costs) to AmerenUE of contracting with an ICT for each category of benefits and costs are summarized in Table 25.

Table 25
Annual Benefits (Costs) to AmerenUE of the ICT Case in comparison to the Midwest ISO Case
(in millions of dollars; positive numbers are benefits)

		Present Value	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2009-11 Present Value
AmerenUE in ICT													
+	Production Cost Savings	**739.6**	113.1	117.0	121.1	119.9	118.6	117.1	111.0	104.5	107.1	109.8	*296.3*
+	Generator Revenue Increases	**74.7**	(58.7)	(22.7)	15.2	17.4	19.7	22.0	37.5	53.8	55.1	56.5	*(61.2)*
+	Load Withdrawal Savings	**(963.7)**	(96.1)	(123.8)	(152.8)	(155.5)	(158.2)	(161.0)	(167.8)	(174.9)	(179.2)	(183.7)	*(311.0)*
+	FTR Value Increases	**(63.2)**	(4.9)	(8.3)	(11.8)	(11.1)	(10.3)	(9.5)	(10.5)	(11.5)	(11.8)	(12.1)	*(20.6)*
+	Net Operating Reserve Savings	**(38.8)**	(3.0)	(5.5)	(8.2)	(7.7)	(7.1)	(6.5)	(6.0)	(5.4)	(5.5)	(5.7)	*(13.8)*
+	Marginal Loss Credit Increases	**29.6**	7.2	5.6	4.0	3.9	3.9	3.9	3.8	3.7	3.8	3.9	*14.5*
+	Capacity Sales	**(9.8)**	(2.7)	(5.4)	(3.6)								*(9.8)*
+	Net Wheeling Rev Increases	**37.9**	5.3	5.5	5.6	5.7	5.9	6.0	6.2	6.3	6.5	6.7	*13.9*
=	Trade Benefits	**(193.8)**	(39.9)	(37.6)	(30.5)	(27.3)	(27.6)	(28.0)	(25.8)	(23.5)	(24.1)	(24.7)	*(91.9)*
+	Admin Charge Savings	**67.4**	11.6	11.4	11.3	10.7	10.1	9.6	9.4	9.2	9.5	9.7	*29.0*
+	RSG and RNU Cost Savings	**116.0**	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	*45.6*
+	1-Time Reconfiguration	**0.0**	0.0										*0.0*
+	Transm Cost Allocation Savings	**31.1**	1.4	2.0	4.9	5.5	5.5	5.9	6.4	6.9	7.0	7.2	*6.8*
+	Addtl Transm Reservations	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*
+	MISO Post-Trans Rev Distribution	**(372.9)**	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)	*(146.7)*
+	FERC Charge Savings	**6.0**	1.5	1.5	1.5	1.6	1.6	0.0	0.0	0.0	0.0	0.0	*3.8*
=	Subtotal Other Charges	**(152.4)**	(25.4)	(24.9)	(22.2)	(22.1)	(22.6)	(24.3)	(24.1)	(23.7)	(23.3)	(23.0)	*(61.4)*
	Total	**(346.2)**	(65.2)	(62.4)	(52.7)	(49.4)	(50.2)	(52.3)	(49.8)	(47.2)	(47.4)	(47.6)	*(153.3)*

8.1.3. Sensitivity Results

The results for each sensitivity case for each category of benefits and costs are summarized in Table 26, Table 27 and Table 28 for the year in which the sensitivity case was conducted.

Table 26
Annual One-Year Sensitivity Analysis Benefits (Costs) to AmerenUE in comparison to the Midwest ISO Case
(in millions of dollars; positive numbers are benefits)

		High Fuel 2011			No Taum Sauk 2011		
		Base 2011	Fuel 2011	Increase in Benefits	Base 2011	No Taum Sauk 2011	Increase in Benefits
	AmerenUE in SPP RTO						
	Increase in Generation (GWh)	*(2,942)*	*(2,643)*	*300*	*(2,942)*	*(2,883)*	*59*
+	Production Cost Savings	99.5	104.4	4.9	99.5	91.1	(8.4)
+	Generator Revenue Increases	18.0	14.7	(3.3)	18.0	21.2	3.2
+	Load Withdrawal Savings	(135.9)	(136.9)	(0.9)	(135.9)	(129.9)	6.0
+	FTR Value Increases	(12.0)	(10.6)	1.3	(12.0)	(11.2)	0.8
+	Net Operating Reserve Savings	(8.9)	(12.9)	(4.0)	(8.9)	(4.4)	4.5
+	Marginal Loss Credit Increases	0.6	0.8	0.2	0.6	1.3	0.7
+	Capacity Sales	(1.2)	(1.2)	0.0	(1.2)	(1.2)	0.0
+	Net Wheeling Rev Increases	(1.7)	(1.7)	0.0	(1.7)	(1.7)	0.0
=	Trade Benefits	(41.7)	(43.4)	(1.7)	(41.7)	(34.8)	6.9
+	Other Savings	(57.4)	(57.4)	0.0	(57.4)	(57.4)	0.0
=	Total Benefits	(99.1)	(100.8)	(1.7)	(99.1)	(92.2)	6.9
	AmerenUE in ICT						
	Increase in Generation (GWh)	*(3,322)*	*(3,429)*	*(107)*	*(3,322)*	*(3,353)*	*(31)*
+	Production Cost Savings	121.1	141.6	20.5	121.1	99.4	(21.7)
+	Generator Revenue Increases	15.2	(7.9)	(23.1)	15.2	34.7	19.5
+	Load Withdrawal Savings	(152.8)	(164.0)	(11.2)	(152.8)	(150.7)	2.1
+	FTR Value Increases	(11.8)	(11.1)	0.7	(11.8)	(11.1)	0.7
+	Net Operating Reserve Savings	(8.2)	(10.6)	(2.4)	(8.2)	(3.7)	4.5
+	Marginal Loss Credit Increases	4.0	4.8	0.8	4.0	7.3	3.3
+	Capacity Sales	(3.6)	(3.6)	0.0	(3.6)	(3.6)	0.0
+	Net Wheeling Rev Increases	5.6	5.6	0.0	5.6	5.6	0.0
=	Trade Benefits	(30.5)	(45.3)	(14.8)	(30.5)	(22.1)	8.4
+	Other Savings	(22.2)	(22.2)	0.0	(22.2)	(22.2)	0.0
=	Total Benefits	(52.7)	(67.5)	(14.8)	(52.7)	(44.3)	8.4

Table 27
Annual One-Year Sensitivity Analysis Benefits (Costs) to AmerenUE in comparison to the Midwest ISO Case

(in millions of dollars; positive numbers are benefits)

		Carbon Tax 2014			Callaway 2 2016		
		Base 2014	**Carbon 2014**	**Increase in Benefits**	**Base 2016**	**Callaway 2016**	**Increase in Benefits**
	AmerenUE in SPP RTO						
	Increase in Generation (GWh)	*(2,672)*	*(5,664)*	*(2,992)*	*(2,587)*	*(3,591)*	*(1,004)*
+	Production Cost Savings	94.5	279.9	185.5	101.3	122.0	20.8
+	Generator Revenue Increases	44.0	(223.0)	(267.0)	58.3	(98.1)	(156.4)
+	Load Withdrawal Savings	(153.2)	(152.3)	1.0	(167.2)	(36.1)	131.1
+	FTR Value Increases	(9.8)	(13.0)	(3.2)	(11.2)	(19.1)	(7.9)
+	Net Operating Reserve Savings	(7.7)	(9.9)	(2.3)	(6.4)	(6.6)	(0.2)
+	Marginal Loss Credit Increases	0.3	0.5	0.1	0.0	1.5	1.5
+	Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0
+	Net Wheeling Rev Increases	(1.9)	(1.9)	0.0	(2.0)	(2.0)	0.0
=	Trade Benefits	(33.8)	(119.6)	(85.8)	(27.2)	(38.3)	(11.2)
+	Other Savings	(60.0)	(60.0)	0.0	(60.7)	(60.7)	0.0
=	Total Benefits	(93.8)	(179.6)	(85.8)	(87.8)	(99.0)	(11.2)
	AmerenUE in ICT						
	Increase in Generation (GWh)	*(3,126)*	*(2,753)*	*373*	*(2,498)*	*(2,812)*	*(314)*
+	Production Cost Savings	117.1	141.8	24.7	104.5	101.6	(2.9)
+	Generator Revenue Increases	22.0	(116.4)	(138.4)	53.8	(97.8)	(151.6)
+	Load Withdrawal Savings	(161.0)	(64.5)	96.5	(174.9)	(18.4)	156.5
+	FTR Value Increases	(9.5)	(11.6)	(2.1)	(11.5)	(14.6)	(3.0)
+	Net Operating Reserve Savings	(6.5)	(10.0)	(3.4)	(5.4)	(5.8)	(0.4)
+	Marginal Loss Credit Increases	3.9	7.8	3.8	3.7	4.1	0.4
+	Capacity Sales	0.0	0.0	0.0	0.0	0.0	0.0
+	Net Wheeling Rev Increases	6.0	6.0	0.0	6.3	6.3	0.0
=	Trade Benefits	(28.0)	(46.9)	(19.0)	(23.5)	(24.5)	(1.0)
+	Other Savings	(24.3)	(24.3)	0.0	(23.7)	(23.7)	0.0
=	Total Benefits	(52.3)	(71.3)	(19.0)	(47.2)	(48.2)	(1.0)

Table 28
Annual One-Year Sensitivity Analysis Benefits (Costs) to AmerenUE in comparison to the Midwest ISO Case

(in millions of dollars; positive numbers are benefits)

			High ICT Seams Charge		Low ICT Seams Charge	
		Base 2011	2011	Increase in Benefits	2011	Increase in Benefits
AmerenUE in ICT						
	Increase in Generation (GWh)	*(3,322)*	*(3,634)*	*(312)*	*(2,894)*	*428*
+	Production Cost Savings	121.1	129.4	8.3	109.9	(11.2)
+	Generator Revenue Increases	15.2	(36.3)	(51.6)	73.1	57.8
+	Load Withdrawal Savings	(152.8)	(112.6)	40.2	(195.6)	(42.8)
+	FTR Value Increases	(11.8)	(10.8)	1.0	(12.7)	(0.9)
+	Net Operating Reserve Savings	(8.2)	(8.2)	0.0	(8.2)	0.0
+	Marginal Loss Credit Increases	4.0	3.5	(0.5)	4.5	0.5
+	Capacity Sales	(3.6)	(3.6)	0.0	(3.6)	0.0
+	Net Wheeling Rev Increases	5.6	5.6	0.0	5.6	0.0
=	Trade Benefits	(30.5)	(33.1)	(2.6)	(27.1)	3.4
+	Other Savings	(22.2)	(22.2)	0.0	(22.2)	0.0
=	Total Benefits	(52.7)	(55.3)	(2.6)	(49.2)	3.4

Ameren Missouri
2015 RTO Cost-Benefit Study
Stakeholder Meeting
September 25, 2014

1. Welcome/Introductions/Expectations
2. Historic Overview
    a. Ameren Missouri's transfer of functional control of its electric transmission system to the MISO was first approved by the MoPSC in March 2004. The approval was for a 3-year period and required a subsequent review of the benefits of continued participation.
    b. Ameren Missouri completed its 2007 RTO Cost Benefit study in October of that year
        i. Compared continued participation in the MISO vs. SPP or ITC
        ii. Findings supported Ameren Missouri's continued participation in MISO.
        iii. The MoPSC granted the extension of authority for Ameren Missouri's continued participation in MISO.
    c. Ameren Missouri sought to further extend this authority in its November, 2010, filing.
        i. Included a high-level update of the 2007 CRA study
        ii. Update supported the extension of the authority to continue participation in MISO to MISO
        iii. MoPSC approved this extension through May of 2016.
3. November 15, 2015 Filing
    a. The MoPSC's April 2012 order required Ameren Missouri to perform a comprehensive study regarding the cost and benefits of extending its transfer of functional control of its electric transmission system to the MISO, as compared to a transfer to SPP or operating as an ITC.
    b. The order contained specific milestones:
        i. Ameren Missouri is to contact and consult with stakeholders regarding the scope of the study by September 30, 2014.
        ii. Upon careful consideration of this stakeholder input Ameren Missouri shall notify the stakeholders of the study parameters by December 1, 2014.
        iii. By November 15, 2015, Ameren Missouri shall file a pleading, along with the results of its actual analysis regarding its continued participation in MISO, or in the alternative transfer of functional control of its transmission system to SPP or its possible operation as an ITC after May 31, 2016.
4. Tentative analysis Discussion
    a. Propose to study the same three scenarios
        i. In MISO
        ii. In SPP
        iii. Operate as an ITC

Exhibit B

   b. Propose the analysis to be very similar to original 2007 CRA study
      i. Calculate the benefits under each scenario
         1. Company energy revenues
         2. Production costs
         3. Company load withdrawals
         4. Transmission rights values
         5. Operating reserve costs
         6. Marginal loss factors
         7. Capacity markets/sales
         8. Transmission revenues
      ii. Calculate administrative and other costs
         1. RTO administrative charges
         2. ICT costs
         3. Revenue Sufficiency Guarantee/Revenue Neutrality/Make-whole costs and or revenues
         4. Transmission build cost allocations
         5. RTO Exit Fees/Reconfiguration costs
      iii. Will have to model SPP's Integrated Marketplace with data from March 1, 2014 through February 28, 2015.
5. Stakeholder Thoughts/Input/Discussion
6. Going Forward
   a. RFP process to select a 3rd party consultant, selection by December 31, 2014.
   b. Solicit written comments and input for consideration through October 24th, 2014.
   c. Ameren Missouri will advise stakeholders of the final model parameters and of the actual analysis Ameren Missouri will do via email prior to the December 1, 2014 deadline.
7. Questions/concerns
8. Adjourn