RTO Cost-Benefit Analysis

Aquila Missouri Electric Utility Operations

Prepared By:

CRA International

March 28, 2007

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

CRA International ("CRA") has conducted a cost-benefit analysis for the Aquila Missouri electric utility operations (collectively, Missouri Public Service and St. Joseph's Light and Power) to assess the impact of potential membership in a Regional Transmission Organization ("RTO"). Other investor-owned utilities with service territories in Missouri[1] are currently members of one of two different RTOs: 1) the Midwest Independent System Operator ("Midwest ISO")[2] and 2) the Southwest Power Pool ("SPP RTO")[3]. As such, the Aquila Missouri companies asked CRA to evaluate the costs and benefits that would accrue to the utility and its customers if Aquila Missouri were to join one of these two RTOs.

Currently, Aquila Missouri has a number of its transmission- and reliability-related functions performed by SPP and the Midwest ISO. Aquila Missouri is a transmission owner under the SPP tariff, and the Midwest ISO is the reliability coordinator for Aquila Missouri. While the potential exists for Aquila Missouri to continue this type of relationship with the two RTOs in the near future, this interim-type status is unlikely to be available over the long-term. As such, in this study it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it performs (or procures) its transmission- and reliability-related functions on its own.[4]

---

1 These Missouri utilities include AmerenUE, a member of the Midwest ISO, and Kansas City Power and Light ("KCP&L") and Empire District, members of the SPP RTO. Aquila Missouri is directly interconnected with the Midwest ISO through AmerenUE, and with the SPP RTO through KCP&L and Westar Energy. During the course of the preparation of this study, Aquila announced a transaction under which Great Plains Energy, the parent of KCP&L, would become the parent of Aquila. Potential impacts of this transaction on the cost-benefit results have not been considered in this study.

2 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.

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 Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual membership fee and its allocated share of SPP's NERC assessment.

As discussed in further detail below, we have found that joining an RTO is expected to provide net benefits to Aquila Missouri. Subject to certain qualitative considerations and modeling assumptions, we have also found joining the SPP RTO to be more beneficial to Aquila Missouri than joining the Midwest ISO.

1.2. METHODOLOGY

The time horizon for this study is the 10-year period from 2008 through 2017. CRA has performed GE MAPS model runs for this period assuming Aquila Missouri is: 1) Stand-alone, 2) a member of the Midwest ISO, or 3) a member of the SPP RTO. 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.

In comparison to the Stand-alone case, the two RTO cases are modeled in GE MAPS with Aquila Missouri: 1) having no wheeling charges for transactions with fellow RTO members, 2) committing its generating units efficiently through an RTO-wide regional optimization process, and 3) operating flowgates at higher capacity levels through market-based RTO congestion management. These factors serve to decrease impediments to Aquila Missouri trade in the RTO cases and thus yield "trade benefits" to Aquila Missouri. In this study, trade benefits are measured as the decrease in the total cost to serve Aquila Missouri load (Aquila Missouri production costs for owned and contracted capacity plus purchased power costs minus "off-system" sales revenue).[5] These trade benefits must be compared to the additional administrative charges that Aquila Missouri would incur by being a member of an RTO.

1.2.1. Midwest ISO and SPP RTO Modeling

Currently, the Midwest ISO and SPP RTO markets are in different stages of development. 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

---

5 Fixed costs that do not change between cases, such as depreciation for owned-generating units are not included in this measure. The cost to serve Aquila Missouri load has not been further separated between wholesale and retail jurisdiction in this study.

institute an ancillary services market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member net energy for load over the next few years.[6]

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.

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. Such analyses are beyond the scope of the type of study that can be easily performed on behalf of a non-RTO utility such as Aquila Missouri.

As such, for purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame evaluated in this study. While it is unlikely that SPP would implement by 2008 the additional market developments in place at the Midwest ISO, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design.

We have further assumed that, under base conditions, the SPP RTO administrative charges per MWh including incorporation of these additional market developments will be similar to those projected by the Midwest ISO. PJM, an RTO with markets in place similar to those of the Midwest ISO, projects administrative charges per MWh of member load similar to those projected by the Midwest ISO. With market development comparable to that of the Midwest ISO, SPP estimates, on a preliminary basis, administrative charges per MWh of market member load in roughly the same range as the Midwest ISO. SPP is currently significantly smaller in terms of market member load than the Midwest ISO and PJM. All else equal, the resulting reduction in economies of scale in operations could result in SPP administrative costs per MWh, with a comparable level of market development, being higher than those incurred by the Midwest ISO and PJM.

6 Administrative charges per MWh of net energy for the load of RTO market members is used in this study as a reasonable approximation for determining Aquila Missouri's administrative charges if a member of an RTO market. In practice, the RTO administrative charges are assessed using a variety of metrics. Market member load distinguishes between members participating in the RTO markets from those that are solely reliability members.

1.3. Findings

1.3.1. Net Benefits of Joining an RTO

As shown in Table 1, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of net benefits over the 2008 to 2017 period.[7]

Table 1
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	**21.1**	**86.9**

As shown in Table 1, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from $30 to $96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are $16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are $23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 1. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be $1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of RTO membership is projected to be $21 to $87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period.[8]

---

7 GE MAPS runs were performed for the calendar years 2008, 2012 and 2017 with results for intervening years interpolated. A present value rate of 8.0% was applied, consistent with Aquila Missouri's after-tax cost of capital. An underlying inflation rate of 2.5% was assumed.

8 These quantitative results are a projection based on a number of modeling assumptions that in practice will deviate from the estimates used herein. As such, the results should be viewed as indicative of the direction of the net benefits rather than a specific computation of the precise level of net benefits that will incur with RTO entry.

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the $23.5 million of RTO administrative charges shown in Table 1 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO. Moreover, qualitative considerations for factors not directly addressed in the quantitative modeling, such as increased price transparency and reduced reliance on Transmission Loading Relief ("TLR") events as a member of an RTO, provide further support for the benefits of Aquila Missouri joining an RTO.

1.3.2. Net Benefits of Joining the Midwest ISO or the SPP RTO

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results in Table 1 indicate a $66 million greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.[9]

The greater benefits for membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and is heavily interconnected with KCP&L in particular. The total tie-line capacity in MVA on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the capacity on the tie-lines that interconnect Aquila Missouri with Midwest ISO market members (AmerenUE).[10]

Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 2, Aquila Missouri generation, which

9 A high natural gas price sensitivity analysis was performed for the year 2012, and indicated that with higher gas prices, the net benefits to Aquila from joining an RTO would increase, and the net benefits of joining the SPP RTO would increase more in dollar terms than the benefits of joining the Midwest ISO.

10 NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case.[11]

Table 2

Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

Table 2 indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members, and thereby providing additional net benefits. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.[12]

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO.

Again, however, the SPP RTO does not yet have the same level of RTO market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

11 Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

12 The Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for $235 million in December 2006 over Aquila Missouri's competing bid of $230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional amount needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of joining the SPP RTO.

2. ANALYTIC FRAMEWORK

In this study, it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it performs (or procures) its transmission- and reliability-related functions on its own.

2.1. CASES ANALYZED

CRA modeled three alternative cases for Aquila Missouri in this study:

- **Stand-alone case.** Aquila Missouri does not join an RTO, and performs (or procures) its transmission- and reliability-related functions on its own.
- **RTO Cases:**
    1. **Midwest ISO case.** Aquila Missouri joins the Midwest ISO as a full member of the RTO participating in all markets and paying all applicable administrative costs.
    2. **SPP RTO case.** Aquila Missouri joins the SPP RTO as a full member of the RTO participating in all markets and paying all applicable administrative costs.

In this study, the Stand-alone case is used as the reference case from which changes in costs and benefits are measured. Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual membership fee and its allocated share of SPP's NERC assessment.

2.2. COSTS AND BENEFITS

The evaluation of the costs and benefits has two basic components:

- **Trade benefits,** which are estimated using energy modeling to obtain the Aquila Missouri cost to supply its load under each case. The energy market simulation uses General Electric's MAPS tool.
- **Administrative costs**, the Aquila Missouri costs to perform transmission-related functions on its own or alternatively to pay administrative charges to the Midwest ISO or SPP RTO and interface with the RTOs.

The time horizon for the study consists of the 10-year period from 2008 through 2017. Detailed energy model simulations were performed for 2008, 2012 and 2017, and interpolation was used to obtain energy modeling results for the other years in the study horizon.[13] A natural gas price sensitivity is performed for the year 2012 only.

2.3. Midwest ISO and SPP RTO Markets

For purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame used in this study Currently the Midwest ISO and SPP RTO are in different stages of market development. 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 had not yet formalized plans for the formation of a capacity market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member load over the next few years.[14]

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 per MWh of market member load roughly 20% below that of the Midwest ISO.

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 the type of study easily performed on behalf of a non-RTO utility such as Aquila Missouri. While it is unlikely that SPP would implement the additional market developments instituted by the Midwest ISO by 2008, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design. We will further consider the ramifications of this assumption in subsequent sections.

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

13 The results for the intervening years were interpolated on a straight-line basis using the MAPS results in 2005 dollars, and then an annual inflation rate of 2.5% was applied.

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

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 Aquila Missouri, current RTO membership was assumed to continue in all cases. 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, including Iatan 2 in 2010. Potential CO_2 policies were not considered in this study. A full description of the GE MAPS inputs is contained in Appendix A.

3.1. Modeling Assumptions by Case

In distinguishing among the three scenarios, CRA worked with three categories of modeling assumptions: 1) wheeling charges, 2) effective flowgate capacity and 3) commitment region. Table 3 illustrates how these assumptions were applied in each case.

Table 3
Modeling Assumptions by Case

Case	Aquila MO Wheeling Charges to/from:			Effective Flowgate Capacity	Aquila MO Commitment Pool
	Midwest ISO	SPP RTO	Others		
Stand-alone	Yes	Yes	Yes	90%	Aquila MO
Member of Midwest ISO	No	Yes	Yes	100%	Midwest ISO
Member of SPP RTO	Yes	No	Yes	100%	SPP

Wheeling Charges: Wheeling charges are charges for moving energy from one control area to another in an electric system. In GE MAPS, wheeling rates 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. Wheeling rates 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.

For this study, the wheeling rates for commitment were based on the day-ahead firm transmission rates (which are generally consistent with non-firm hourly on-peak rates) in the Aquila Missouri, Midwest ISO and SPP tariffs, while the rate for dispatch is based on non-firm hourly off-peak rates. This is to take into account that the day-ahead commitment process, in considering reliability, is more conservative in the type of capacity that is expected to be available.

The default assumption applied for wheeling rates on inter-ties in the modeled Eastern Interconnection region, other than between members of the same RTO, was $2 per MWh for both commitment and dispatch. Based on the Aquila Missouri tariff, the Aquila Missouri wheeling out rate in the Stand-alone case was also set at $2 per MWh for both dispatch and commitment.[15] Based on the Midwest ISO tariff, the wheeling rate from the Midwest ISO to SPP was set at $4 per MWh for dispatch and $6 for commitment.[16] Based on the SPP tariff, the wheeling rate from SPP to the Midwest ISO was set at $2 per MWh for both commitment and dispatch.[17] 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.

Effective Flowgate Capacity: For the Stand-alone case, transfer limits on flowgates in the Aquila Missouri region were decreased by 10% to reflect the inefficiency of congestion management through the Transmission Loading Relief ("TLR") process. Flowgates are combinations of critical transmission elements that have the potential to become overloaded due to power flows on the transmission system. The 10% decrease was applied only to those Aquila Missouri flowgates directly impacted by transmission elements outside of the Aquila Missouri control area. The 10% figure was also applied in the SPP cost-benefit study performed by CRA in 2005 based on an examination of historical SPP tie-line flows during TLR events. Because of the uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in the process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

In contrast, RTO markets use market-based congestion management. Locational pricing is used to provide price signals that disclose congestion, signaling generation to redispatch, and enabling market participants to select alternative purchasing opportunities. This process ultimately relieves congestion more quickly and precisely than the TLR process. As a result, flowgates can be managed closer to their transfer limits under market-based congestion management.

15 Wheeling rates were rounded to the nearest $/MWh integer, as is required in MAPS. The Aquila Networks rate is currently $2.07 per MWh on-peak and $0.98 per MWh off-peak for 345/161 kV service. SPP OATT, Rate Sheet for Point-To-Point Transmission Service for Aquila Networks – MPS/L&P. The Stand-alone wheeling rates for commitment and dispatch were both set to $2/MWh to be consistent with the default modeled region assumption for individual control areas.

16 Midwest ISO, Updated Discounted Pricing Information, oasis.midwestiso.org/doscuments/miso/pricing_new.html, as of January 30, 2007.

17 SPP through and out rates are based on the zone from which the power exits SPP's transmission system. The $2 rates are based on the Point-To-Point Transmission Service rates in the SPP OATT for KCP&L and SWPA inter-ties to the Midwest ISO market (i.e., to AmerenUE). For Westar Energy inter-ties to Aquila Missouri in the case when Aquila Missouri is in the Midwest ISO, the Westar Energy wheeling rate was set at $5 per MWh for commitment and $3 per MWh for dispatch based on the Westar Energy point-to-point rates in the SPP OATT.

Commitment Region: For the Stand-alone case, the day-ahead commitment of generating units for Aquila Missouri was performed for the Aquila Missouri control area, including jointly-owned units outside of the control area. As a Stand-alone entity, Aquila Missouri must commit its own resources in order to ensure control area reliability, as it would have limited ability to rely on external entities for commitment of their resources absent a contractual arrangement. For the RTO cases, the Aquila Missouri commitment was part of a pool-wide commitment encompassing the RTO, in which the unit commitment is optimized on a regional basis subject to transmission limitations. The ability to rely on the commitment of units across a broader region in the RTO markets allows for a more efficient unit commitment process.

4. BENEFITS AND COSTS

4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)

This study assesses the benefits and costs associated with Aquila Missouri participating in the Midwest ISO or SPP RTO relative to Stand-alone status. Welfare for the regulated customers of Aquila Missouri, 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, energy purchases, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, RTO administrative costs, and Aquila Missouri internal implementation and operating costs. Trade benefits were computed using the GE MAPS results for each case. 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 (Aquila Stand-alone and Aquila in RTO) reflect varying degrees of impediments to trade between Aquila and surrounding regions. In particular, the wheeling rates and flowgate restrictions between Aquila and the Midwest ISO and SPP RTO in the Stand-alone case result in impediments to trade that are reduced when Aquila is a member of an RTO. Reductions in the impediments to trading should generally result in production cost savings. 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. 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.

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. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.[18]

4.2.1. Measurement of Aquila Missouri 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 Aquila Missouri 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, Aquila Missouri's utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Deriving trade benefits for Aquila Missouri thus requires an analysis of both the production cost of operating the Aquila Missouri owned generating plants and the associated Aquila Missouri trading activity (purchases and sales).

The production cost of the Aquila Missouri-owned generating units is derived directly from the MAPS outputs for each case. This includes Aquila Missouri's share of jointly owned units, and its long-term contractual ownership of generating capacity, as shown in Appendix B. Other than its share of Iatan 2, no additional Aquila Missouri owned units were assumed in this study.

18 Consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefit of $4 ($2 + $2) will match the total production cost saving of $4.

For purposes of deriving the impact of trading with adjoining regions, the net hourly MAPS tie-line flows into and out of Aquila Missouri were used as a proxy for purchase and sale transactions by Aquila Missouri. In each hour, the net interchange was derived using Aquila Missouri tie-line flows to assess whether Aquila Missouri was a net importer (purchaser) or exporter (seller) of power. If a net purchaser in the hour, the net purchase amount was multiplied by the weighted average split-savings price for tie-lines with flows into the Aquila Missouri control area. Similarly, if Aquila Missouri was a net exporter (seller) in the hour, the net sale amount was multiplied by the average split-savings price for tie-lines with outgoing flows. The split-savings prices reflects a 50/50 sharing of the price difference (and trade benefits), adjusted for the applicable wheeling charge, across the MAPS tie lines between Aquila Missouri and adjacent control areas. This also means that to the extent that Aquila Missouri has trade benefits, adjacent control areas are sharing in those trade benefits.

Prior to this hourly net interchange calculation, an adjustment is made to the Aquila Missouri tie-line flows for the power produced by the Aquila Missouri jointly-owned and contracted units located outside of the Aquila Missouri control area. The generation and production costs for Aquila Missouri's share of units located outside of the Aquila Missouri control area are included in Aquila Missouri's total generation and production costs. For purposes of this study, it is assumed that Aquila Missouri purchases the output of the 580 MW Aries combined-cycle unit located in the Aquila Missouri control area at prevailing locational market prices. To the extent that such an arrangement would require an additional capacity-type payment to the merchant unit, it is assumed this payment would be the same in each of the cases. As an intra-control-area unit purchase, these Aries purchases are included in the generation category in the tables in this study along with other Aquila unit purchases.

Wheeling charges on net hourly imports into Aquila Missouri are paid by the native load in Aquila Missouri, and are included in the Aquila Missouri purchase costs in this study. Wheeling charges on net hourly exports from the Aquila Missouri control area are paid by the load in the importing control area to Aquila Missouri (thereby reducing the net Aquila Missouri transmission revenue requirement) and are included in the Aquila Missouri sales revenue in this study.

4.2.2. Trade Benefit Results

Table 4 shows the change in Aquila Missouri generation, purchases and sales for the years 2008, 2012 and 2017 in the RTO cases in comparison to the Stand-alone case. As shown, there is a reduction in generation in the RTO cases. However, the reduction is significantly greater in the SPP RTO case. Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

Table 4
Increase in Aquila Missouri Generation, Purchases and Sales in RTO in comparison to Stand-alone Status (GWh)

	Member of Midwest ISO			Member of SPP RTO		
	2008	2012	2017	2008	2012	2017
Generation	(94)	(258)	(381)	(1324)	(2173)	(2562)
Purchases	348	556	497	959	1788	2330
Sales	254	299	116	(364)	(386)	(232)
Net (G+P-S)	0	0	0	0	0	0

Table 5 lists the trade benefits (i.e., the change in the net cost to serve load) to Aquila Missouri in the RTO cases in comparison to the Stand-alone case. The change in the generation costs, purchase costs and sales revenue correspond to the changes in the GWh of generation, purchases and sales shown in Table 4. As shown, the trade benefits are positive for both RTO cases, but more positive for the SPP RTO case.

Table 5
2008-2017 Trade Benefits to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Decrease in Production Costs	45.9	673.4
Decrease in Purchase Costs	(103.5)	(465.5)
Increase in Sales Revenues	87.6	(112.1)
Total Trade Benefits	**29.9**	**95.7**

The production costs listed in Table 5 are comprised of the fuel, variable O&M, start-up and emissions costs for Aquila Missouri generating units, including Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area. For purposes of Table 5, the production costs also include the purchase of the output of the merchant Aries unit at prevailing market prices.

The greater trade benefits resulting from membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and heavily interconnected with KCP&L in particular. The total MVA capacity rating on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the ratings on the lines that interconnect

Aquila Missouri with Midwest ISO market members (AmerenUE).[19] Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that over the tie-lines to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 6, Aquila Missouri generation, which is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case. This reduction in generation in the SPP RTO case indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.

Table 6
Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

As noted above, the Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for $235 million in December 2006 over Aquila Missouri's competing bid of $230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional energy needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of the SPP RTO case.

19 NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

4.3. Administrative and Operating Costs

A number of costs must be analyzed in addition to those directly addressed in GE MAPS. These include Aquila implementation and operating costs and RTO administrative charges. The specific categories of costs addressed in this study are discussed in detail below.

4.3.1. Stand-alone Costs to Provide Current SPP and Midwest ISO Functions

In addition to its long-running role as Aquila Missouri's NERC reliability council, SPP performs a number of other reliability/transmission provider functions for Aquila Missouri, namely: 1) tariff administration, 2) OASIS administration, 3) available transmission capacity (ATC) and total transmission capacity (TTC) calculations, 4) scheduling agent, and 5) regional transmission planning. The Midwest ISO performs a sixth needed function, reliability coordination, for Aquila Missouri. As discussed previously, moving to Stand-alone status would require Aquila Missouri to procure these six services from an alternative supplier or provide them internally. In turn, however, Aquila Missouri would avoid payment to SPP and the Midwest ISO for provision of these functions.

Appendix C provides an overview of the analysis performed by Aquila Missouri personnel to estimate the costs to provide or procure these six reliability/transmission provider functions on a Stand-alone basis. The costs were then converted by CRA into annual revenue requirements. The analysis indicates that Aquila Missouri would incur additional costs of $16.0 million over the 10-year study period to provide these six functions. Since this is an additional cost for the Stand-alone case, the $16.0 million is counted as a savings (or benefit) to each of the two RTO cases in comparison to Stand-alone status.

4.3.2. 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 that would be payable by Aquila if it were to be an RTO member. 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.[20] 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). SPP RTO charges are expected to be about 20% lower on a cents per MWh basis 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

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

include any administrative charges for a day-ahead market, financial transmission rights, and an ancillary services market.

At the request of CRA, SPP provided a preliminary forecast of charges to be incurred upon development and operation by SPP of a day-ahead market, FTRs, and an ancillary services market. On a preliminary basis, SPP projected costs per MWh of member load roughly equivalent to those of the Midwest ISO upon full institution of these additional markets.

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.[21] For purposes of this study, given that the RTO markets are assumed to have similar markets and operations over the long-term study period, the projected Midwest ISO administrative charges were applied in both the Midwest ISO and SPP RTO cases.[22]

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.

- The Midwest ISO has a number of deferred charges that are being assessed over time to its members. The market-related deferred charges were $80.8 million as of the end of 2005, and are projected to be recovered by 2011.[23] These deferred charge recoveries are offset by amortization to members of about $45 million over

21 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.

22 The Midwest ISO projected unit charges through 2011. After 2011, the annual RTO administrative charges for Aquila Missouri were assumed to escalate at inflation.

23 Midwest ISO, Annual Report 2005, pages 29-30.

the 2007 to 2011 period resulting from the exit charges that have been paid to the Midwest ISO.[24] SPP does not have similar deferred charges at this time. All else equal, this likely favors SPP having somewhat lower unit administrative charges until these Midwest ISO deferrals are completed.

Using the Midwest ISO projection of administrative costs, the Aquila RTO cases are projected to incur $23.5 million (2007 present value) in RTO administrative charges over the 10-year study period. See Appendix C for further detail. This is an additional cost to the two RTO cases in comparison to the Stand-alone case.

4.3.3. 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 under a non-RTO (Stand-alone) basis, there will be higher FERC charges to RTO members than non-RTO members, all else being equal.

For purposes of this study, the difference in the FERC charges between the Stand-alone and RTO cases was estimated by comparing the FERC charges estimated by the Midwest ISO (on a dollars per load served basis) in 2007 to the average inflation-adjusted FERC charges paid by Aquila Missouri in the 2004–2005 period. This annual difference was then escalated at inflation and discounted over the 10-year study period. Using this approach, the increase in FERC fees for Aquila Missouri under the two RTO cases is $1.3 million (2007 present value) over the study period in comparison to the Stand-alone case. See Appendix C for further detail.

4.3.4. Aquila Internal RTO Market Participation Costs

RTO market participants will incur expenditures to participate in an RTO market over and above the RTO administrative charges. However, in order to interface and trade with surrounding RTOs, Aquila Missouri has already invested in the computer systems and staff

24 Midwest ISO, Recommended 2007-2009 Budget, page 5, December 14, 2006.

training needed to interact with the RTOs. This includes investment in an OATT system. As such, no further additional internal costs have been included for Aquila in the RTO cases.

4.4. Overall Cost-Benefit Results

Table 7 provides the benefits (shown as positive numbers) and costs (shown as negative numbers) discussed above for Aquila membership in the Midwest ISO or SPP RTO in comparison to Stand-alone status. As shown, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of the net benefits over the 2008 to 2017 period.

Table 7
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	**21.1**	**86.9**

As shown in Table 7, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from $30 to $96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are $16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are $23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 7. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be $1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of being in an RTO is projected to be $21 to $87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period (see Appendix C).

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the $23.5 million of RTO administrative charges shown in Table 7 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO.

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results indicate a greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO. Nonetheless, the SPP RTO does not yet have the same level of market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

4.4.1. High Gas Price Sensitivity

Given historic volatility in natural gas prices, CRA also conducted a one-year sensitivity analysis of the impact that much higher natural gas prices would have on net benefits. The natural gas price forecast used in the GE MAPS modeling (see Figure 1 in Appendix A) declines substantially from 2008 through 2012 in accordance with current natural gas market futures. The average natural gas price projected for the Henry Hub of $7.60 per MMBtu (2005$) in 2008 declines to $5.60 by 2012.

Given this projected decline already included in the base modeling, a relatively large increase in gas prices was tested in the 2012 gas sensitivity model runs to address the potential for 2012 gas prices to be significantly higher than 2008 levels. Specifically, the gas prices applied for 2012 in this sensitivity case were increased from $5.60 to $9.00 per MMBtu (2005$), or to a level about 18% higher than base 2008 gas prices. As shown in Table 8, with these high gas prices, the 2012 trade benefits for the Midwest ISO and SPP RTO cases increase significantly.

Table 8
Impact of Higher Gas prices on 2012 Aquila Missouri Trade Benefits (Costs) from RTO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

2012 Trade Benefits	Member of Midwest ISO	Member of SPP RTO
With Base 2012 Gas Prices	3.7	16.1
With High 2012 Gas Prices	10.6	28.0
Increased Benefits (Costs)	**6.1**	**11.8**

Relative to the base gas price case, the high gas price case for 2012 shows a greater percentage increase in trade benefits for membership in the Midwest ISO, but a higher absolute increase in benefits for membership in the SPP RTO. These results support the finding that with a significantly higher level of gas prices, the decision for Aquila to join an RTO would become even more favorable.

5. QUALITATIVE CONSIDERATIONS

Aside from the specific benefits quantified above, participation in an RTO is likely to provide additional benefits, along with some cost risks, as discussed below.

Regional Transmission Management. Participation in an RTO is likely to assist Aquila Missouri in the regional management of parallel path flows, management of reserve sharing, and the regional coordination/planning of transmission investment. These benefits result from addressing issues at a regional level rather than that of a local control area unable to examine or to be fully cognizant of the actions of surrounding areas that can impact their local control area. The RTO real-time markets should allow for economic redispatch to alleviate the need for TLR events. TLR is a real-time operating procedure that allows reliability coordinators to mitigate violations of reliability limits through curtailments and redispatch actions. The need for a TLR often arises when transaction schedules are not fully-coordinated among control areas in advance of real-time operations. Finally, single region-wide OASIS administration should also provide additional efficiencies relative to Aquila Missouri in Stand-alone status.

Price Transparency. The inclusion of a transmission system in a transparent regional market with locational price signals will provide additional incentives to improve generation availability when economic to do so, and will help in the planning process in placing transmission improvements and new generation capacity in optimal locations. The transparency of the pricing provides an additional tool for regulators to monitor the efficiency of utility purchases and sales

Costs. Aside from the specific issues identified above, one of the main concerns regarding RTO membership has been the magnitude of the administrative charges, and the perception that individual members may not have enough ability to directly control the underlying RTO expenditures. In response, the Midwest ISO has reduced its budgeted expenditures[25] and 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

25 Midwest ISO Trims Operating Costs, Midwest ISO News Release, June 19, 2006.

transparency in evaluating RTO costs.[26] 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.

Market Monitoring. Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. Both the Midwest ISO and SPP have established independent market monitors. In CRA's view, Aquila Missouri's entry into an RTO is unlikely to increase significantly the likelihood of actual exercises of market power in the Aquila Missouri region. This is because most power delivered within Missouri will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners would have little, if any, incentive to withhold generation from the RTO markets for the purpose of increase in the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, the issue is likely to be a minor consideration in the decision to join an RTO. Nonetheless, it is important that the RTO market monitors review the performance of their markets to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

6. CONCLUSION

The results of the quantitative analysis show a net benefit for Aquila Missouri joining either the Midwest ISO or the SPP RTO. Qualitative considerations further buttress the likelihood of net benefits resulting from RTO entry by Aquila Missouri. The quantitative results indicate a greater benefit for Aquila Missouri to join the SPP RTO than the Midwest ISO. The relative benefits are high enough to offset potentially greater administrative costs at SPP given its smaller size. These quantitative results are premised on additional market developments in the SPP RTO that have not yet been formally proposed or budgeted. Thus, there is uncertainty regarding the timing and cost of these additional SPP market developments.

26 RTO Costs to be Reflected in Accounting Rules, FERC News Release, Docket No. RM04-12-000,, December 15, 2005

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 province of Ontario with the major focus on the SPP, Midwest ISO and surrounding regions. The GE MAPS simulations focus on the ten-year period from 2008 to 2017. The years directly simulated are 2008, 2012 and 2017. 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 Platt's and 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 cases for the summer of 2007 and 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).

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 and Entergy are included. For other study areas, a constraint is included only if it has been binding in our previous studies 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 (2006) 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 9 and Table 10 documents these generic assumptions.[27] As is the case throughout this MAPS analysis, all costs are in real 2005 dollars.

27 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.

Table 9: 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 10: Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start (% of Capac-ity)	Spinning Reserve (% of Capac-ity)	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

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, including Iatan 2 in 2010. For study years 2012 and 2017, CRA added capacity based on economic and/or reliability criteria using CRA's proprietary CRA's North American Electricity & Environment Model (NEEM). Capacity additions are made such that each capacity region complies with its specified reserve margin. New capacity can also be added if the economics of adding new capacity result in lower present value on-system electric sector costs over the time horizon of the model (i.e., reduced operating costs more than offset capital costs). The choice of new capacity will depend on a number of key inputs, but foremost on capital costs of the new capacity and fuel costs. Capital costs used in NEEM are generally based on information included in EIA's Annual Energy Outlook 2006, with adjustments for such factors as the recent run-up in steel prices, additional costs of adding transmission and natural gas pipeline. The natural gas and oil prices described herein that are applied in the MAPS model are also applied in the NEEM model.

The least cost capacity decisions from NEEM are then added to the MAPS database for balancing purposes. 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.

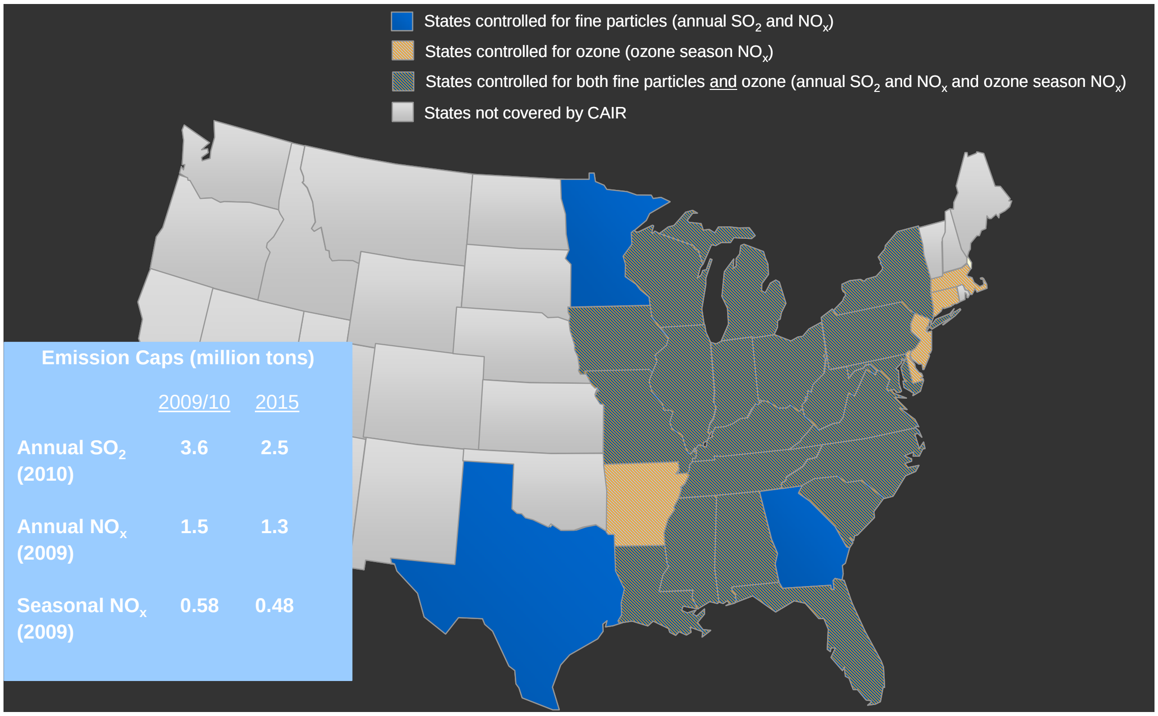
7.8. Environmental Regulations

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 11 below. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

Table 11: Forecast Emission Allowance Prices

	Non-CAIR SO2 ($/Ton)	CAIR SO2 ($/Ton)	NOx ($/Ton)
2008	615	615	1450
2012	397	794	1665
2017	363	1039	2051

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. 2008 emission permit prices are obtained from a Cantor Fitzgerald on-line resource. Allowance price forecasts for 2012 and 2017 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 province of Ontario. 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 VOM 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. Table 12 shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

Table 12: Operating Reserve Requirements

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%
Midwest ISO	2,250 MW	65%
MAPP	871 MW	65%
SPP	1,746 MW	65%
MIPU stand alone	85 MW	65%
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.

7.12. WHEELING RATES

Wheeling rates are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, wheeling rates 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. Wheeling rates 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. For the current analysis, the wheeling rates for commitment were based on the day-ahead firm transmission rates in the individual companies' tariffs, while the rate for dispatch was based on the non-firm hourly rates.

Table 13 gives an overview of the wheeling rates between SPP, MISO, Aquila and other neighboring control areas for the Stand-alone and RTO cases

Table 13: Wheel-out Rates for SPP, Midwest ISO and Aquila Missouri

From	To	Commitment	Dispatch
Midwest ISO	SPP	$6	$4
SPP (other than Westar)	Non-SPP	$2	$2
Westar	Non-SPP	$5	$3
Midwest ISO	PJM	$0	$0
Midwest ISO	Non-Midwest ISO/Non-SPP/non-PJM	$2	$2
Aquila Missouri Stand-alone	All	$2	$2
Non-Midwest ISO MAPP companies	All	$2	$2
AECI	All	$2	$2
TVA	All	$2	$2
Entergy	All (including SPP)	$2	$2
LG&E	All	$2	$2
Cleco	All (including SPP)	$2	$2

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 drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States. 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 December 6, 2006. For 2013 through 2025, CRA uses the EIA Annual Energy Outlook (AEO2006) Reference Case forecast[28]. 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.

28 AEO 2006 does not forecast Henry Hub Prices, but predicts prices at the wellhead instead. A historical multiplication factor of 1.129 is used to derive the Henry Hub price forecast.

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 December 6, 2006. 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 2005 $/MMBtu)

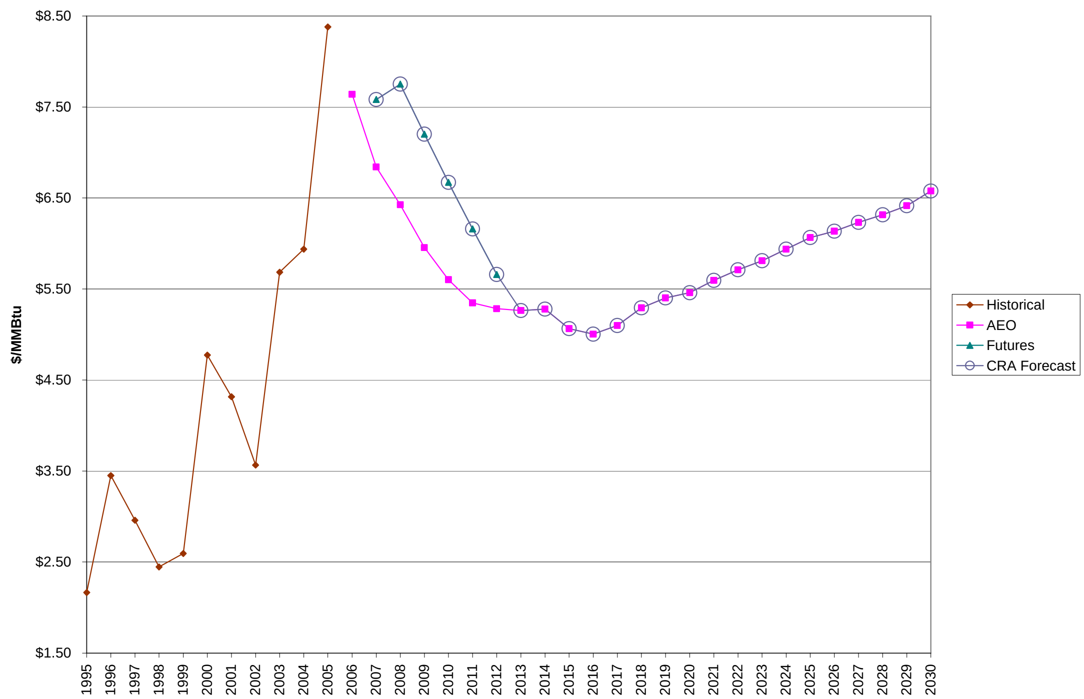
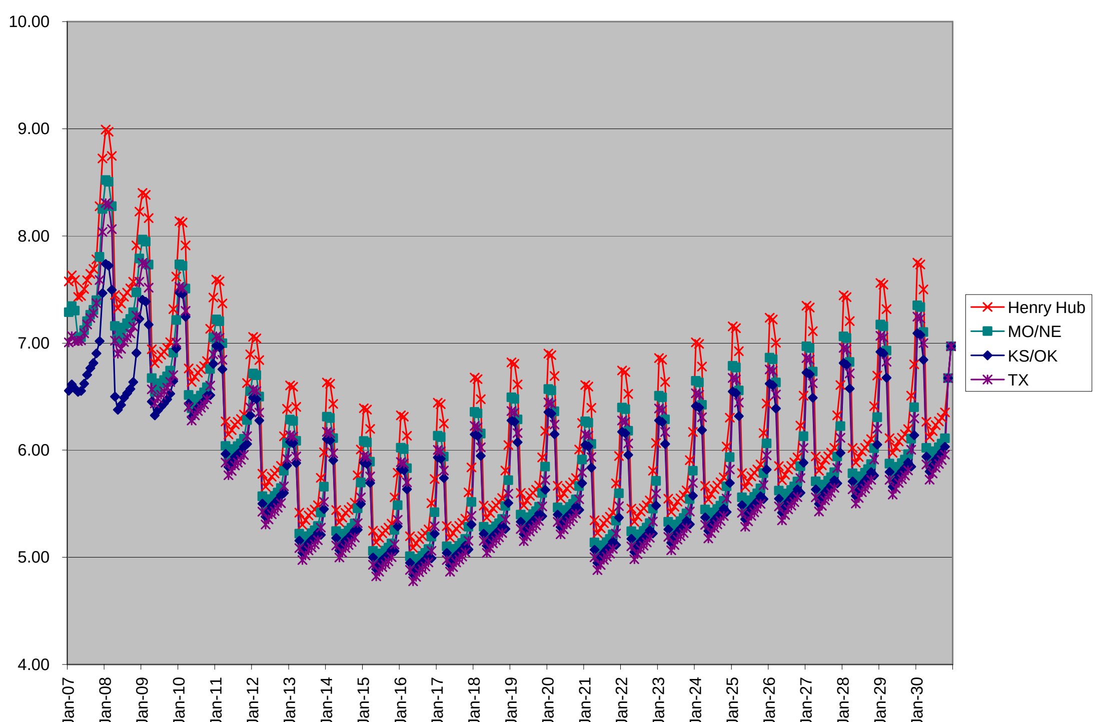


Figure 3. Forecast Regional Natural Gas Prices (Real 2005 $/MMBtu)



7.14.2. Fuel Oil Price Forecast

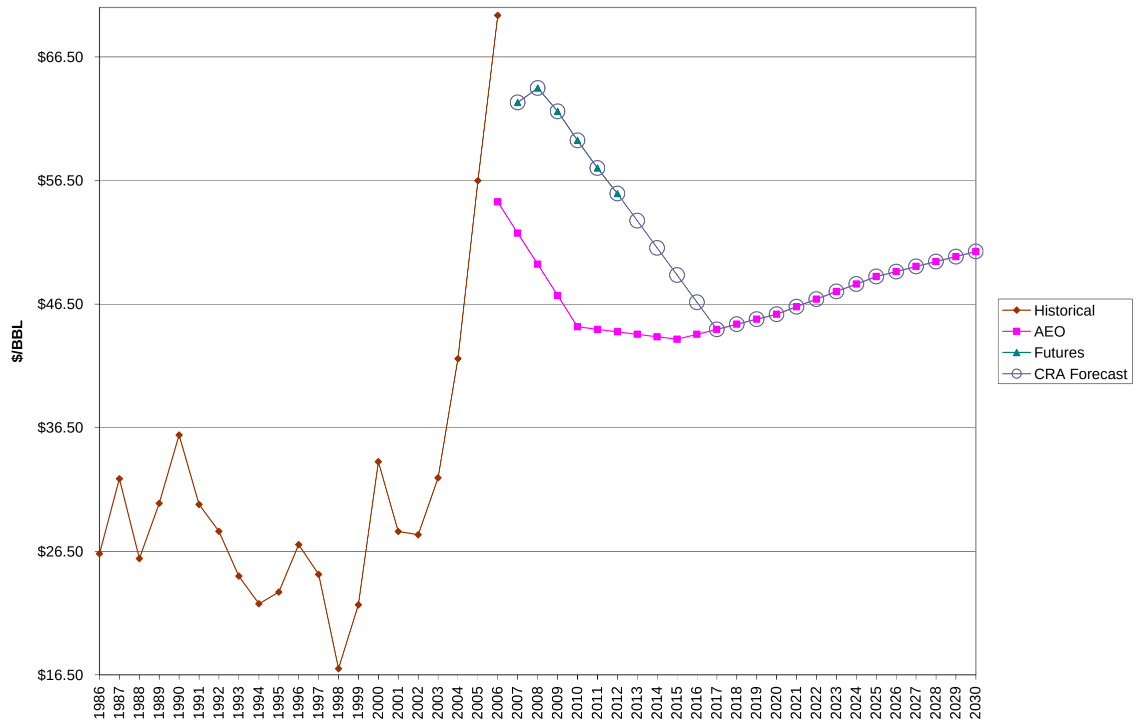
Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

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 December 6, 2006. For 2013, 2014 and 2015 the forecast is an interpolation between the futures and the AEO2006. Through 2030, CRA uses the AEO2006 Reference Case forecast. CRA Base Case forecast for light sweet crude oil is presented on Figure 2.

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. New York Harbor prices for the Base Case forecast are shown in Figure 5. 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 2005 $/BBL)



7.15. NATURAL GAS PRICE SENSITIVITY ASSUMPTION

A natural gas price sensitivity case was performed for the year 2012 in which the Henry Hub natural gas prices shown in Figure 2 were increased to $9.00 per mmBTU (2005$). The 2012 generation fuel prices were then recreated using the methodology discussed above. No changes were made to fuel oil, coal or nuclear fuel prices.

8. APPENDIX B: AQUILA MISSOURI RESOURCES

Table 14 lists the Aquila Missouri generation resources for the 2008 to 2017 period. The jointly-owned units and the long-term unit purchases are located outside of the Aquila Missouri control area.

Table 14
Aquila Missouri Generating Capacity

(MW, summer rating)

Existing Units		
Greenwood 1-4	232.0	
Iatan 1	117.7	*Jointly-owned*
Jeffrey 1-3	175.2	*Jointly-owned*
KCI 1-2	33.6	
Lake Road 1-7	268.8	
Nevada	20.0	
Ralph Green	71.0	
Sibley 1-3	508.3	
South Harper	315.0	
	1741.6	
Long-term Purchases		
Cooper	75.0	*Ends May 2011*
Gentleman 1-2	100.0	*Ends Jan. 2014*
	175.0	
New Capacity		
Iatan 2	153.0	*2010 ISD, Jointly-owned*
Merchant Capacity in Aquila-Mo Control Area		
Aries	580.0	

9. APPENDIX C: SUPPORTING DETAIL

9.1. ANNUAL RESULTS

9.1.1. Member of Midwest ISO

The projected annual benefits (costs) to Aquila Missouri of being a member of the Midwest ISO for each category of benefits and costs are summarized in Table 15.

Table 15
Annual Benefits (Costs) to Aquila Missouri of Midwest ISO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in Midwest ISO											
+ Production Cost Savings	**45.9**	2.9	3.6	4.3	5.1	5.9	7.5	9.1	10.8	12.6	14.5
+ Purchase Cost Savings	**(103.5)**	(11.4)	(12.7)	(14.1)	(15.5)	(17.0)	(17.2)	(17.4)	(17.7)	(17.9)	(18.1)
+ Sales Revenue Increases	**87.6**	15.3	15.2	15.1	14.9	14.8	13.2	11.6	9.9	8.1	6.2
= Trade Benefits	**29.9**	6.8	6.1	5.3	4.5	3.7	3.5	3.3	3.0	2.8	2.5
+ Savings Trans/Rel Functions	**16.0**	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administative Charges	**(23.5)**	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	**(1.3)**	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	**(8.8)**	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	**21.1**	5.5	4.9	4.1	3.3	2.4	2.2	1.9	1.6	1.3	1.0

9.1.2. Member of SPP RTO

The projected annual benefits (costs) to Aquila Missouri of being a member of the SPP RTO for each category of benefits and costs are summarized in Table 16.

Table 16
Annual Benefits (Costs) to Aquila Missouri of SPP RTO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in SPP RTO											
+ Production Cost Savings	**673.4**	80.2	85.0	90.0	95.2	100.7	105.9	111.4	117.1	123.0	129.1
+ Purchase Cost Savings	**(465.5)**	(49.4)	(53.3)	(57.3)	(61.5)	(65.8)	(73.1)	(80.7)	(88.7)	(97.0)	(105.7)
+ Sales Revenue Increases	**(112.2)**	(16.1)	(16.7)	(17.4)	(18.0)	(18.7)	(17.8)	(16.8)	(15.8)	(14.7)	(13.6)
= Trade Benefits	**95.7**	14.7	15.0	15.4	15.8	16.1	15.0	13.8	12.6	11.2	9.8
+ Savings Trans/Rel Functions	**16.0**	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administative Charges	**(23.5)**	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	**(1.3)**	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	**(8.8)**	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	**86.9**	13.4	13.8	14.2	14.5	14.8	13.7	12.5	11.2	9.8	8.3

9.2. ADMINISTRATIVE AND OPERATING COSTS

9.2.1. Savings from RTO Provision of Transmission Functions

At the request of CRA, Aquila Missouri staff estimated the additional costs that Aquila Missouri would incur to provide on a Stand-alone basis the six transmission/reliability functions currently provided by SPP and the Midwest ISO on a Stand-alone basis. These costs would be avoided (and replaced by RTO administrative charges) if Aquila Missouri were to join an RTO. The key assumptions behind the cost figures are summarized below.

Function 1. Reliability Coordination

For Aquila Missouri to provide its own reliability functions (the direct actions required to maintain adequate generation capacity, adequate system voltage levels, and transmission system loading within specified limits), five additional FTE system operators would be required along with a $205,000 investment in additional computer hardware/software. Also there would be approximately $10,000 per year needed for software licensing/maintenance fees.

Function 2. Tariff Administration

In order to provide tariff administration such as processing long term transmission service requests, performing feasibility and impact studies, managing billing, and handling regulatory issues would require addition of one FTE planning engineer.

Function 3. OASIS Administration

This function comprises administration of transmission service, including provision of qualified staff and supervision for day and night coverage and procurement and maintenance of the necessary telecommunications infrastructure to support the service. Information updated would include ATC, response to service requests, transmission limitations, transmission reservation policy, and various FERC required postings. To maintain the OASIS on a full time basis would require three additional FTE system operators in the system operations area. In addition a capital investment of approximately $15,000 would be required for additional computer equipment and software.

Function 4. ATC/TTC Calculations

In order to perform required transmission capacity calculations, one FTE planning engineer would be required.

Function 5. Scheduling Agent

For Aquila to perform this service, two clerical FTEs would be required to check out all transactions with customers on a daily basis, and in addition two FTE system operator would be required to track and administer tags on a daily basis.

Function 6. Regional Transmission Planning

The transmission planning function would consist of developing load flow planning models with a 10 year horizon, developing a database and performing stability studies, performing transmission expansion and operating studies, develop transmission pricing models. Part of this work is already performed by Aquila transmission planning personnel. To assume the planning study work now done by SPP would require the addition of one FTE planning engineer.

Aquila Missouri personnel provided O&M (including benefits) and capital addition costs for the years 2008 through 2017. CRA converted the capital additions into revenue requirements, and also applied an A&G adder to the projected wages as shown in Table 17.

Table 17

Annual Costs for Aquila Missouri to Provide Transmission/Reliability Functions

(in thousands of dollars)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 Reliability Coordination										
Wages	390	399	409	419	430	441	452	463	475	486
Benefits	195	200	205	210	215	220	226	231	237	243
Other O&M	10	11	11	11	11	12	12	12	12	13
Total O&M	595	609	625	640	656	673	689	707	724	742
Capital Additions	210					238				
2 Tariff Administration										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
3 OASIS Administration										
Wages	234	240	246	252	258	264	271	278	285	292
Benefits	117	120	123	126	129	132	136	139	142	146
Other O&M	5	5	5	5	4	6	6	6	5	5
Total O&M	356	365	373	382	391	403	412	422	432	443
Capital Additions	15					15				
4 ATC/AFC/TTC Calculations										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
5 Scheduling Agent										
Wages	238	244	250	256	262	269	276	283	290	297
Benefits	119	122	125	128	131	135	138	141	145	148
Total O&M	357	366	375	384	394	404	414	424	435	445
6 Transmission Planning										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
TOTAL										
Wages	1076	1103	1131	1159	1188	1218	1248	1279	1311	1344
Benefits	538	552	565	580	594	609	624	640	656	672
Other O&M	16	16	16	16	16	18	18	18	18	18
A&G (a)	473	485	497	510	522	535	549	563	577	591
Total O&M and A&G	2103	2156	2209	2264	2320	2380	2439	2499	2561	2625
Capital Additions										
Capital Additions	225					253				
Rev Requirement	78	71	65	58	52	87	80	72	65	58
Total	2181	2227	2274	2322	2372	2467	2519	2572	2627	2683

(a) *Estimated at 44% of Wages based on Aquila-MO 2004/5 FERC Form 1 Ratio of A&G Office Supplies and Expenses to A&G Salaries*

9.2.2. RTO Administrative Costs

The annual RTO administrative costs were estimated using the forecast of expenditures per MWh of market member load as projected by the Midwest ISO as shown in Table 18. Aquila Missouri expenditures subsequent to 2011 were assumed to escalate at inflation.

Table 18

Annual RTO Administrative Charges for Aquila Missouri

RTO Administrative Charges			**2008**	**2009**	**2010**	**2011**
Aquila-MO Net Annual Energy	(GWh)	(a)	8,823	9,074	9,322	9,572
RTO Administative Charges	($/MWh)	(b)	0.373	0.358	0.356	0.356
Aquila-MO RTO Admin Charges	($000)		3,291	3,248	3,319	3,408

(a) - SPP 2006 IE-411, page 24.
(b) - Midwest ISO, Recommended Capital and Operating Budget, December 14, 2006, page 5.

9.2.3. Additional FERC Charges

The annual additional FERC charges in 2007 dollars that would be incurred by Aquila Missouri if a member of an RTO are provided in Table 19. The additional cost was assumed to increase at inflation through the study period.

Table 19: Additional FERC Annual Charges if in RTO

(in thousands of dollars unless noted)

Historical FERC Charges for Aquila-Missouri

(Source: FERC Form 1, Page 350, Regulatory Commission Expenses)

	MPS	L&P	Total	2007$ (c) Multiplier	2007$ Total
2004	148.8	120.2	269.0	1.0875	292.6
2005	91.5	111.8	203.3	1.0549	214.4
Average					**253.5**

FERC Charges if in RTO:

2007 MISO Estimated Schedule 10 FERC Charges (a)	32,333	(a)
2007 MISO Estimated Schedule 10 GWH (load)	650,847	
2007 FERC Charges per $/MWh of load	0.050	
Aquila-MO 2007 Estimated Net Energy for Load (GWh)	8,586	(b)
Aquila-MO 2007 Annual FERC Charge if in RTO	**426.5**	

Increase in FERC Charges if in RTO (2007$) **173.0**

(a) - Midwest ISO, Schedule 10 FERC Rate, forecast 2007 dollars for MISO

(b) - SPP 2006 IE-411, page 24.

(c) GDP Deflator:

7/1/2004	*109.728*	
7/1/2005	*113.121*	
7/1/2006	*116.420*	
7/1/2007	*119.331*	*@2.5%*