Exhibit No.:
Issues: Aquila's Application to Join Midwest ISO
Witness: Michael S. Proctor
Sponsoring Party: MoPSC Staff
Type of Exhibit: Cross-Surrebuttal Testimony
Case No.: EO-2008-0046
Date Testimony Prepared: February 27, 2008

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

CROSS-SURREBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

Aquila Inc.
d/b/a Aquila Networks – MPS and Aquila Networks – L&P
CASE NO. EO-2008-0046

Jefferson City, Missouri
February 27, 2008

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	)	Case No. EO-2008-0046

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the following Cross-Surrebuttal Testimony in question and answer form, consisting of 50 pages of Cross-Surrebuttal Testimony to be presented in the above case, that the answers in the following Cross-Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S. Proctor
Michael S. Proctor

Subscribed and sworn to before me this 25th day of February, 2008.

JEREMY HAGEMEYER
Notary Public - Notary Seal
State of Missouri - County of St. Louis
My Commission Expires Feb. 17, 2009
Commission #05560562

Jeremy Hagemeyer
Notary Public

My commission expires 2/17/09

Table of Contents

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d/b/a Aquila Networks – MPS and Aquila Networks – L&P ("Aquila)

CASE NO. EO-2008-0046

Q. What is your name and business address?

A. My name is Michael S. Proctor. My business address is 9900 Page Avenue, Suite 103, Overland, MO 63132.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as Chief Regulatory Economist in the Energy Department.

Q. Are you the same Michael S. Proctor who previously filed rebuttal testimony in this case on behalf of the staff of the Commission (Staff)?

A. Yes, I am.

SUMMARY OF CROSS-SURREBUTTAL POSITION OF STAFF

Q. Why are you testifying in cross-surrebuttal?

A. The witnesses for the Midwest Independent System Operator (MISO) and the City of Independence criticize the cost-benefit analysis performed by CRA International (CRA) and raised other issues in their rebuttal testimonies. I explain why those criticisms and issues have not caused the Staff to change its recommendation to the Commission that it <u>not</u> grant Aquila's request for authorization to join MISO.

Q. What is the Staff's approach in this case?

A. The cost-benefit analysis provided by Aquila in direct testimony and performed by CRA International (CRA) using the GE-MAPS combined production-cost / power-flow model showed Aquila in SPP with greater net benefits than Aquila in MISO. Based on those results, the Staff concluded that Aquila joining MISO would be detrimental to the public interest. At the same time the Staff was aware of MISO criticisms of the CRA cost-benefit analysis performed for Aquila, and the Staff was also aware that MISO intended to have additional analysis performed to address MISO's criticisms. MISO had CRA perform that additional analysis, and presented its view of that analysis in the rebuttal and supplemental rebuttal testimony of its witnesses. In turn, the Staff evaluated the rebuttal testimonies of MISO, the further CRA analysis submitted in supplemental rebuttal testimony of MISO with associated work papers, and the rebuttal testimony of City of Independence and their witnesses to determine if there was sufficient cause for the Staff to change the recommendation the Staff made in rebuttal testimony that the Commission <u>not</u> grant Aquila's request for authorization to join MISO. They did not.

Q. What conclusions has the Staff reached concerning the cost-benefit analysis presented by MISO in its supplemental rebuttal testimony?

A. Based on my review of the additional CRA cost-benefit analysis performed at MISO's request, I do not believe there is sufficient evidence to support Commission authorization for Aquila to join MISO. Moreover, the analysis performed at MISO's request for 2008 still indicates that the net benefits from Aquila joining SPP are greater than Aquila joining MISO. Moreover, based on a comparison of the results of the additional analysis comparing Aquila in MISO versus Aquila in SPP, my conclusion is that Aquila in MISO results in greater congestion between Aquila's load and its participating, baseload generation resources located outside the Aquila control area (*i.e.*, Iatan, Jeffrey, Gentlemen and Cooper). It is because of this difference on congestion in the transmission system that Aquila in SPP shows greater trade benefits than from being in MISO, including both higher levels of generation from external baseload generating units and lower market prices for Aquila load. In addition, I have several reservations concerning the details (assumptions and results) of the additional cost-benefit analysis presented in supplemental rebuttal testimony on behalf of MISO. I address the details of my reservations later in this testimony.

Q. What issues does the City of Independence raise in the rebuttal testimony of its witnesses Messrs. Volpe and Mahlberg that you address in this testimony?

A. I address the City of Independence's claims of greater access to electric markets if Aquila is in MISO than if Aquila is in SPP, its concern regarding the differences between the SPP and MISO markets, as well as its concerns about higher administrative costs for SPP than for MISO. In brief, I do not agree with the conclusions reached by the City of Independence, and find that its claims and concerns do not provide credible evidence upon which the Commission should rely for authorizing Aquila to join MISO.

CROSS-SURREBUTTAL OF MR. DOYING'S REBUTTAL

Q. What witnesses for MISO filed rebuttal or supplemental rebuttal testimony in this case?

A. Mr. Richard Doying (Vice President of Market Operations for MISO) and Mr. Johannes P. Pfeifenberger (Consultant with the Brattle Group) both filed rebuttal testimony on behalf of MISO. Mr. Pfeifenberger also filed supplemental rebuttal testimony on behalf of MISO.

Q. What is your understanding of the purpose of Mr. Doying's rebuttal testimony?

A. My understanding is that Mr. Doying is presenting and quantifying Regional Transmission Organization (RTO) benefits he believes were not captured by trade benefits estimated in the CRA cost-benefit study Aquila submitted. Mr. Doying describes these benefits in terms of the broader "value proposition" of being in an RTO. Specifically, he states these benefits include: "(1) improved reliability; (2) improved efficiency; and (3) improved opportunities for development of generation and transmission infrastructure." [Doying Rebuttal at page 8, lines 14-16]. Mr. Doying points out the benefits included for improved efficiency are likely to be duplicative of those captured in the cost-benefit study filed by Aquila. While improved reliability and improved development benefits are difficult to monetize, MISO has attempted to do so with a resulting range of dollar savings for the MISO RTO, of which 1.7% are attributed to Aquila based on its percentage share of load in the MISO footprint (*i.e.*, Aquila's "load ration share"). The ranges of dollar benefits for Aquila in MISO estimated by Mr. Doying are shown in the following table.

Table 1: Aquila Benefits per Doying

Source	Range: Millions
Improved Reliability	\$4.0 - \$5.9
Improved Efficiency	\$7.7 - \$10.3
Improved Development	\$2.3 - \$2.6

The range of benefits for improved reliability and development for Aquila are from \$6.3 million (M) to \$8.5 M per year, slightly less than the range of benefits estimated for improved efficiency. Mr. Doying completes his rebuttal testimony with a list of non-quantifiable benefits from participating in an RTO.

Q. Do you agree with Mr. Doying's estimate of the range of benefits associated with improved efficiency?

A. No, I do not. The reason is that the application of a load ratio share of benefits for estimating savings in production costs from enhanced trade (trade savings) does not properly take into account the degree of congestion that exists between Aquila and MISO. This is illustrated by the size of the benefits estimated in Mr. Doying's range [$7.7 M to $10.3M] compared to the estimate of trade benefits calculated by Mr. Pfeifenberger [$0.7 M]. When an estimate is off by a factor of 10 or greater, then it is clear that using Aquila's load ratio share does not provide a reasonable estimate.

Q. Do you agree with Mr. Doying that improved reliability and improved development opportunities are benefits from being in an RTO?

A. Yes, I do. In addition, I agree with his list of non-quantifiable benefits from RTO participation that occur because of greater market transparency and improved regional planning. However, with Federal Energy Regulatory Commission (FERC) Order 890, regional planning benefits will also begin to occur for those utility transmission systems not located in an RTO.

Regarding the dollar level of benefits, I requested work papers concerning Mr. Doying's estimated range of benefits for improved reliability and infrastructure opportunities, and based on the materials provided, it appears that these types of benefits are generally attributable to all RTOs. Therefore, to the extent they are correctly quantified for Aquila in MISO a similar quantification would apply for Aquila in SPP.

Q. Why is it clear that these types of benefits from improved reliability Mr. Doying quantifies are generally applicable to RTOs?

A. I'll illustrate with an example taken from Mr. Doying's work papers. MISO's estimate of benefits from improved reliability is based on the product of three components: (Reduced probability of transmission outage)*(Reduced MWhs per transmission outage) ($ per MWH of transmission outage). MISO estimated benefits relative to both small and large outage events.

<u>Small Outage Events</u>: In order to estimate reduced probability of a transmission outage, MISO specific data was used for outages before and after MISO operations as an RTO (before MISO at 15 outages/yr vs. after MISO at 5.4 outages/yr). For small outage events, there was an estimated reduction in MWhs per outage from being in an RTO due to a smaller level of unmet load (118.2 MWs) and a lower outage duration (7.6 hours). The cost of an outage was estimated from the cost of the 2003 blackout at between $7,440 and $11,160 per MWh. The product of these factors, including a 25% factor for progressive load recovery, estimates a benefit of from $15.9 M to $23.8 M per year in savings from participating in MISO.

<u>Large Outage Events</u>: MISO estimates: 1) lost load for a large event will decrease from 50% to 33% due to an RTO; and 2) Outage duration drops from 72 hours to 59 hours with an RTO. The probability of a large outage event of once every 20 years, the cost per MWh of a large outage (same as for small outage) and the 25% progressive load recovery factor are assumed the same for both with and without an RTO. This results in an estimated annual benefit of $210 M to $316 M per year.

Based on work papers supplied by Mr. Doying, the reductions for large outage events appear to be generic estimates of savings from being in an RTO. While the estimate of benefits from small outage events did use MISO specific calculations related to the reduction in outage events, the estimate of RTO benefits from reduction in size and duration of large outages dominates the calculation of these MISO specific benefits. Thus, the vast majority of reliability benefits would also be attributable to Aquila in SPP.

Q. How did MISO quantify Aquila's improved opportunities for development of generation and transmission infrastructure if it is in an RTO?

A. MISO's estimate of RTO benefit is based on a 1% to 1.25% reduction in Aquila's planning capacity margin. The study MISO relied on was performed for another RTO (California ISO) and affirmed to some extent by MISO internal calculations. MISO's calculated range of benefits for Aquila was based on capacity costs of $1,200/kW, which appears to be representative of the cost of a combined cycle unit. This estimate of cost savings for reducing the planning capacity margin is higher (2x) than the cost of a combustion turbine that is used for reserves.

The reduction in planning capacity margin is attributed to the pooling of capacity throughout the RTO region. However, with Aquila's weak level of interconnection to MISO, it not likely that Aquila would benefit from being able to reduce its reserve margins by belonging to a MISO planning reserve sharing group. It is more likely that Aquila would benefit from reduced planning reserves by remaining in the SPP for purpose of planning reserve sharing group.

Q. What are your conclusions regarding Mr. Doying's rebuttal testimony?

A. The level of benefits estimated by Mr. Doying should not be an issue in this case, as efficiency benefits provide sufficient evidence that Aquila' membership in an RTO is not detrimental to the public interest. While Mr. Doying's rebuttal testimony strengthens the argument for Aquila joining an RTO, it does not address my primary concern that the efficiency benefits from Aquila joining MISO are estimated to be less than those from Aquila joining SPP.

CROSS-SURREBUTTAL OF PFEIFENBERGER REBUTTAL AND SUPPLEMENTAL REBUTTAL

Q. What is your understanding of the purpose of Mr. Pfeifenberger's rebuttal and supplemental rebuttal testimonies?

A. As I indicated in my rebuttal testimony, MISO informed me that it had hired the Brattle Group to review the CRA cost-benefit study filed by Aquila, and planned to address several issues it believed may have caused the study to show greater net benefits from Aquila joining SPP than Aquila joining MISO. In his testimony Mr. Pfeifenberger raises three primary issues with the CRA cost-benefit study Aquila filed: 1) pool commitment of generation associated with the Dogwood plant; 2) Scheduled maintenance of the Sibley 3 plant with Aquila in MISO; and 3) CRA's method for applying wheeling charges to imports of power.

Mr. Pfeifenberger addressed the first issue in his rebuttal testimony where he calculated uplift charges associated with the Dogwood plant and presented results of running the GE-MAPS model used by CRA without the Dogwood plant. In his surrebuttal testimony he corrected his belief stated in his rebuttal testimony as to the cause of what he believes is over dispatch of the Dogwood plant that occurred for the scenario of Aquila standalone and Aquila in MISO in CRA's analysis performed for Aquila.

Mr. Pfeifenberger then discussed further changes to the GE-MAPS model that he had CRA run for 2008. When the results of this further analysis indicated that Aquila in SPP still resulted in higher net benefits than Aquila in MISO, Mr. Pfeifenberger raised the additional two criticisms of the CRA study—scheduled maintenance and pricing of import power. I address each of these issues below.

A. THE POOL COMMITMENT ISSUE ASSOCIATED WITH THE DOGWOOD PLANT

Q. What is your understanding of what Mr. Pfeifenberger means by the term "pool commitment" as he uses that term in his rebuttal testimony?

A. What Mr. Pfeifenberger describes as "pool commitment" is a logic in the GE-MAPS model used by CRA to compare Aquila standalone, Aquila in MISO and Aquila in SPP where generating units committed to serve load are restricted to only units included in each pool. For example, in the Aquila standalone scenario, all generating units in Aquila's control area are in the pool, while in the RTO scenarios, all generating units in the RTO geographic footprint are in the pool. There appear to be two exceptions to the foregoing. First, through joint ownership and purchased power contracts Aquila participates in generating units ("participating units") that are not within its control area. In the pool commitment, these participating units can be committed to meet Aquila's load. Second, if there is insufficient capacity to meet Aquila's load, then generating units from other pools can be committed. This would only occur in a situation where random forced outages would leave Aquila with insufficient capacity to meet its load. This second situation does not appear to be operative in the CRA analysis for any of the three scenarios (Aquila standalone, Aquila in MISO and Aquila in SPP).

Q. What issue does Mr. Pfeifenberger raise with respect to when the Dogwood (formally Aries) generation plant is committed and run as part of the pool commitment in the model CRA used for the analysis Aquila filed?

A. The issue that Mr. Pfeifenberger presented in his rebuttal testimony is that the pool commitment logic of the GE-MAPS program used by CRA appears to commit and run the Dogwood plant (a combined cycle unit) when it is cheaper to commit combustion turbines (CTs); and, instead of running these CTs, Aquila purchases energy from the market.

In reviewing the results of the original CRA analysis I determined that this commitment of the Dogwood plant occurs in periods when the baseload plants in which Aquila participates are out of service for scheduled maintenance and Aquila requires additional capacity committed to serve load for purposes of reliability. Mr. Pfeifenberger's position is that the modeling should allow Aquila the option of purchasing alternative power from third parties for the purpose of generation unit commitment. Given that this issue raised by Mr. Pfeifenberger occurs only when baseload units are down for maintenance, this alternative power from third parties should be seen as substitute power for those baseload units that are out of service. Historically, Aquila, like most utilities, has arranged contracts for purchased power in periods when its baseload generation is scheduled out for maintenance.

Q. Do you agree with Mr. Pfeifenberger that Aquila purchasing energy from third-parties as an alternative to committing the Dogwood plant to serve load should be allowed in the modeling?

A. While I agree with Mr. Pfeifenberger's concern, I would limit Aquila's purchases of energy from third-parties to purchases made under bilateral agreements Aquila uses to provide substitute power during maintenance outages on Aquila's baseload generating units. In addition, a primary question that needs to be answered regarding MISO's concern is why is the commitment of the Dogwood plant a problem for Aquila in MISO, but not a problem for Aquila in SPP. In what follows, I will attempt to more completely address Mr. Pfeifenberger's criticism of the commitment of the Dogwood plant as well as the alternative that he has proposed for cost-benefit analysis CRA performed for MISO.

Q. Is the commitment of the Dogwood plant modeled in the CRA analysis an issue for the Aquila standalone scenario?

A. I believe that pool commitment is a realistic view of Aquila as a standalone utility. Thus, the major issue is not the use of pool commitment logic; instead it is the commitment of the Dogwood plant when that plant is not one of Aquila's own resources. When the Dogwood plant is removed from the analysis (a sensitivity run requested by Mr. Pfeifenberger), Aquila's net generation costs actually decreased (see table 2 of Mr. Pfeifenberger's rebuttal testimony that shows a decrease of $ 7.2 M, from $231.3 M to $224.6 M). Apparently this is because the Dogwood plant has a positive megawatt minimum running level at which it must run if committed, but the CTs have a zero megawatt minimum running level. When the unit commitment logic evaluates alternatives, it compares the cost of running the Dogwood plant to running the CTs to meet load without taking into account economy purchases, and because the Dogwood plant is cheaper, it is chosen. However, in the dispatch logic (as opposed to unit commitment logic) of the GE-MAPS model CRA used, it is cheaper to import energy and pay wheeling charges from adjacent pools rather than to obtain energy from either the Dogwood plant or the CTs. The problem is that once the Dogwood plant is committed it must operate at its minimum running level, and therefore must run at an average cost that is above the market price for that plant. This difference between average cost and market price is what is being called "uplift" charges.

Q. How could this issue be addressed in the Aquila standalone scenario?

A. I believe this issue should have been addressed by including contracts for purchased power during periods when Aquila's baseload units are scheduled to be out of service and adding a unit commitment hurdle rate for the Dogwood plant. This sensitivity run would have provided better information than running the model without the Dogwood plant, as CRA did at Mr. Pfeifenberger's request.

Q. Is the commitment of the Dogwood plant modeled in the CRA analysis an issue for the Aquila in MISO scenario?

A. When Aquila is in MISO, all of the units in MISO are available to meet the pool-wide unit commitment. Had there been sufficient transmission into Aquila from MISO, the commitment of the Dogwood plant would not have been a problem, as other generation from MISO would have been committed to meet Aquila's load. However, because of limited transmission between MISO and Aquila and the resulting high levels of congestion, it appears that imports from the MISO pool were not available for unit commitment, and the Dogwood plant had to be committed to meet Aquila's load. Subsequently, Aquila imported energy (not from MISO, but from other pools where there was sufficient transmission) to substitute energy for all but the minimum megawatt level of the Dogwood plant. Thus, in the Aquila in MISO scenario, unit commitment of the Dogwood plant was also a problem. What is important to note is that for Aquila in SPP this problem did not occur. This is because there is sufficient transmission between SPP and Aquila to provide unit commitment for Aquila's load from other SPP units within the same pool. In my view, this is a strong indication that Aquila in SPP is a better choice than Aquila in MISO.

Q. Does Mr. Pfeifenberger's supplemental rebuttal testimony reflect any attempts by him to correct the foregoing issues associated with the commitment of the Dogwood plant?

A. Yes. Instead of allowing for contracts when baseload generation is scheduled out for maintenance, Mr. Pfeifenberger discarded the pool dispatch approach used in the CRA analysis performed for Aquila and went to a system-wide unit commitment that would commit all units to meet system-wide load. In addition, he placed hurdle rates on the Dogwood plant. In my view, going to a system-wide unit commitment is likely to bias the results in favor of the Aquila standalone scenario by allowing units outside those owned or under contract to Aquila to be used to meet Aquila's commitment obligation without properly reflecting the costs associated with this option. In essence, Aquila gets the benefit in the model of being a part of a very large pool, when in fact that pool is restricted to Aquila's own units. This approach gives Aquila hour-to-hour flexibility in arranging substitute energy for its baseload units that are out of service. The justification for this is the assumption that Aquila will be able to arrange highly flexible short-term contracts at relatively low costs that will allow it to do this. Unless this unsupported assumption is correct, the use of system-wide unit commitment is very likely to underestimate Aquila's costs in the standalone scenario.

In addition, for the Aquila in MISO scenario, using the system-wide unit commitment logic of the GE-MAPS program allows Aquila to import energy from outside the MISO pool to meet its energy needs on a highly flexible basis. In essence, while Aquila is in the MISO pool, it is allowed to gain the advantage of other pools, including SPP, to meet its energy needs. While this advantage of being able to import from other pools is also true for Aquila in SPP scenario, the original cost-benefit results filed by Aquila indicate that unit commitment of the Dogwood plant is not critical for Aquila in SPP and therefore does not add as much benefit for that scenario as for the Aquila in MISO scenario.

In summary, instead of going to a system-wide unit commitment, a less biased correction would have been one in which: 1) pool commitment is retained; 2) contracts are put into the model for substitute power when Aquila's baseload units are scheduled out for maintenance; and 3) a unit commitment hurdle rate is placed on the Dogwood plant.

Q. How do the Aquila standalone adjusted production costs in the analysis Mr. Pfeifenberger had CRA run to correct the Dogwood commitment problem compare to the adjusted production costs in the original CRA analysis the results of which Aquila submitted through the direct testimony of its witnesses?

A. Adjusted production costs are defined as production costs plus purchase power costs minus revenues from sales. This is the same type of metric the Staff uses in its determination of production costs in rate cases. The original adjusted production costs for Aquila standalone were $231.8 M for 2008. These adjusted production costs dropped to $212.4 M in the supplemental run. This decrease of $19.1 M is significantly larger than the $7.2 M estimate provided in table 2 of Mr. Pfeifenberger's rebuttal testimony. This difference of $11.9 M (= $19.1 M - $7.2 M) gives a rough estimate of the bias in favor of Aquila standalone that occurs from running the GE-MAPS model using system-wide unit commitment. Therefore, I do not believe this lower level of $212.4 M is representative of the adjusted production costs that Aquila would incur as a standalone utility, because, as I explained previously, this estimate gives Aquila the option of highly flexible energy on a system-wide basis, when in fact it would be restricted to much less flexible bilateral contracts for substitute power that are likely to incur higher costs.

Q. For the Aquila standalone scenario, why are you concerned about the degree of flexibility that a system-wide unit commitment provides in purchasing substitute power?

A. First, substitute power typically is purchased in fixed blocks of energy and may include additional costs for capacity, particularly when this is a contract for firm power under what are called liquidated damages. Substitute power contracts are typically must-take; *i.e.*, the purchaser does not have the option of going to the market and buying power to substitute for the contract when that power is cheaper. Availability of firm power on a substitute basis for Aquila standalone is dependent on the availability of firm point-to-point transmission. All of these elements contribute to a much less flexible situation than being able to commit other available generation on a system-wide basis. By allowing Aquila standalone to purchase, hour-to-hour from the entire system, the model will underestimate the costs to Aquila standalone and will bias the results against Aquila being in an RTO.

Q. How do the Aquila in MISO and Aquila in SPP adjusted production costs in the CRA analysis performed for MISO runs compare the original adjusted production costs in the CRA analysis performed for Aquila?

A. For the Aquila in MISO scenario, the 2008 adjusted production costs dropped from $225.4 M to $211.7 M, a decrease of $13.7 M. For the Aquila in SPP scenario, the 2008 adjusted production costs dropped from $218.0 M to $207.2 M, a decrease of $10.8 M. Notice that the CRA analysis performed for MISO result in both RTOs still having lower adjusted production costs than in the Aquila standalone case ($5.2M lower for Aquila in SPP and $0.7M for Aquila in MISO), but the margin of difference has significantly narrowed. For the reasons stated previously, the results of these CRA analysis performed for MISO represent a very conservative view of the savings in adjusted production costs when comparing the in RTO scenarios to the Aquila standalone scenario. In addition, Aquila in SPP still has $4.5 M greater trade benefits in this one year (2008) than Aquila in MISO. Finally, the system-wide unit commitment logic also biases the results in favor of Aquila in MISO by not restricting highly flexible substitute energy to the MISO pool. While this bias also exists for Aquila in SPP, it is much less because of the greater number of interconnections between Aquila and SPP.

Q. You state there is a bias that results from system-wide unit commitment when Aquila is in MISO. What is the cause of that bias?

A. Instead of restricting unit commitment to the pool, in system-wide unit commitment Aquila is allowed to commit units from the entire system. Thus, when Aquila is in MISO, it is allowed to commit units from pools such as SPP and Associated Electric Cooperatives Inc. (AECI). To commit to units in other pools, Aquila must overcome the unit commitment hurdle rates placed on these units.

In the CRA analysis performed for Aquila, Aquila in MISO was not able to take advantage of the MISO pool for unit commitment because of the lack of transmission interconnections to MISO. Thus, Aquila had to commit the Dogwood plant and incur uplift costs, as was also the case for Aquila standalone. Recall that in the model runs CRA performed for Aquila, this was not an issue for Aquila in SPP because transmission interconnections between SPP and Aquila were sufficient to allow Aquila to take advantage of the SPP pool for unit commitment. With the CRA analysis for MISO which used system-wide unit commitment, this advantage disappeared. Moreover, Aquila in MISO can take advantage of generation in the SPP pool or the AECI pool to use for its unit commitment by overcoming the unit commitment hurdle rate. Thus, using system-wide unit commitment with fairly moderate unit commitment hurdle rates result in a bias in favor of Aquila in MISO compared to Aquila in SPP.

To quantify that bias, recall the CRA analysis performed for MISO shows savings of $13.7 M for Aquila in MISO, but savings of only $10.8 M for Aquila in SPP. This difference of approximately $3 M is a general indication of the level of the advantage from using system-wide commitment that the Aquila in MISO scenario receives over the Aquila in SPP scenario.

Q. Have you estimated the economic advantages associated with using a system-wide unit commitment instead of modeling power contracts for substitute power?

A. No, I have not. To make such an estimate, a rerun of the CRA model would be required for each of the three scenarios (Aquila standalone, Aquila-in-MISO and Aquila-in-SPP) using the pool commitment logic CRA performed for Aquila in the GE-MAPS model but include short-term power purchases for Aquila during periods when its baseload units are scheduled to be out of operation for maintenance. I submitted a data request to Aquila to determine the extent to which it currently enters into such contracts. In response to the data request, Aquila provided information on two such replacement power contracts it entered into during 2007 when its Sibley 3 unit was scheduled out of service for maintenance. Thus, there appears to be a historical basis for Aquila's use of bilateral contracts to provide replacement power when its baseload units are scheduled out of service. Significantly more detailed information would be required than was provided in response to my data request to model replacement power in the CRA analysis. However, based on the information I received from

Aquila, I believe that this is likely to be the most reasonable approach to dealing with the unit commitment problem that Aquila faces when its baseload units are scheduled out of service for maintenance.

Q. In addition to including system-wide dispatch and hurdle rates for the Dogwood plant, did Mr. Pfeifenberger make any other changes to the analysis CRA performed for Aquila?

A. Yes. Mr. Pfeifenberger had CRA change the unit commitment and dispatch logic so that Aquila was exempted from hurdle rates on its participation units not located in Aquila's control area. While I fully agree with this change, I don't believe this change significantly impacts the results. The reason I believe the impact is insignificant is because all of Aquila's participation units are baseload units that will be committed irrespective of the unit commitment hurdle rates. Even with unit commitment hurdle rates, Aquila is not charged transmission wheeling rates on power taken from its participation units. However, where dispatch hurdle rates could make a minor difference is in the dispatch of these participation units if Aquila has generation units within its control area that are competitive with these participation units. In that case, if a competitive generation unit was slightly more expensive than one of the participation units, the dispatch hurdle rate could result in the slightly more expensive unit being dispatched rather than the less expensive participation unit.

Q. Did Mr. Pfeifenberger have CRA make other changes to the CRA analysis for Aquila when CRA performed its analysis for MISO?

A. Yes. Mr. Pfeifenberger also requested that unit commitment hurdle rates be increased to be $2/MWh higher than unit dispatch hurdle rates. These hurdle rates are imposed on units outside the pool in which Aquila is assumed to be located, and are used only in the unit commitment and unit dispatch logic. However, because of the Joint Operating Agreement between MISO and PJM, the unit commitment rate between MISO and PJM was set equal to the unit dispatch rate between the two RTOs. In general, unit commitment hurdle rates should reflect firm transmission rates, while unit dispatch hurdle rates should reflect non-firm transmission rates. Mr. Pfeifenberger's change appears to reflect non-firm transmission rates for unit dispatch hurdle rates, and instead of using firm transmission rates for unit commitment, he simply adds $2/MWh to the non-firm transmission rate. The $2/MWh adder for unit commitment appears to reflect the largest difference between firm and non-firm transmission rates that was originally specified in the CRA analysis. This higher adder appears to be used because of the use of the system-wide dispatch instead of the pool dispatch used in the original analysis CRA performed for Aquila. The problem here is not with the higher adder, but whether or not the higher adder is sufficient to offset the bias from using a system-wide dispatch. Because this is a fairly minor increase in unit commitment rates from firm transmission rates, it is unlikely that this adder goes very far to eliminate the bias from system-wide dispatch.

Q. Did Mr. Pfeifenberger have CRA make any changes to the analysis it performed for Aquila to reflect differences between the level of MISO and SPP market development?

A. Yes. Mr. Pfeifenberger requested that small unit commitment and hurdle rates be placed on control areas within the SPP footprint to reflect SPP's current lack of a day-ahead energy market. If this change is made, then the RTO costs for SPP also need to be reduced to reflect the lower administrative costs associated with not having to implement a day-ahead energy market. As indicated in my rebuttal testimony, if the reduction in trading benefits from not having a day-ahead market exceeds the cost of implementation, then Mr. Pfeifenberger's change would result in an underestimate of benefits for Aquila in SPP. Moreover, in my view, the purpose of performing a ten-year analysis is not to reflect the various stages of market development in the two RTOs. Rather it is to ensure that changes in generation and transmission additions that are likely to occur in the near future within each RTO do not have a major impact on the results. The argument that being in SPP could result in less trade benefit for the next few years is myopic in scope. The Commission should be making a decision about Aquila joining an RTO based on a longer-term view of benefits to Aquila and its customers.

B. THE SCHEDULED OUTAGE ISSUE ASSOCIATED WITH SIBLEY 3

Q. After CRA modified the analysis it performed for Aquila to implement Mr. Pfeifenberger's changes did Mr. Pfeifenberger report the results of the new analysis and argue they support the Aquila in MISO scenario?

A. No, he did not, because they do not support the Aquila in MISO scenario. As pointed out earlier in my cross-surrebuttal testimony, the results of the supplemental runs of the GE-MAPS model performed for MISO continue to show a $4.5 M advantage in 2008 for Aquila in SPP. Instead, Mr. Pfeifenberger raised additional issues with the CRA analysis. [Pfeifenberger Supplemental Direct at page 7, lines 4-15].

Q. What additional issues did Mr. Pfeifenberger raise?

A. One of these issues is that maintenance of Aquila's Sibley 3 unit was scheduled during the fall in the Aquila in MISO scenario, but during the spring in the Aquila in SPP scenario [Pfeifenberger Supplemental Direct at pages 7-15]. In the model CRA used for its analysis, market prices for electricity are higher in the fall than in the spring, thus the cost of substitute power for the Sibley 3 unit was higher in the Aquila in MISO scenario. Mr.

Pfeifenberger estimates this cost difference to be approximately $1.9 M [Pfeifenberger Supplemental Direct work papers: Excel spreadsheet – Sibley Outage and Excel spreadsheet – Trade Benefits BRATTLE RUN].

Q. What is the impact of the Sibley 3 maintenance issue on adjusted production costs?

A. Mr. Pfeifenberger estimates an additional $1.9 M in trade benefits from moving Sibley 3 maintenance from the fall to the spring. I have reviewed Mr. Pfeifenberger's estimate of $1.9 M, and while it appears to be a reasonable "back of the envelope" estimate, the only way to determine the appropriate cost changes is to run all three scenarios (Aquila standalone, Aquila in MISO and Aquila in SPP) using the same generation unit maintenance schedules.

Q. What is the impact of adding estimated trade benefits of $1.9 M in comparing Aquila in MISO to Aquila in SPP?

A. Using the results from the CRA analysis performed for MISO, subtracting $1.9 M from the adjusted production cost for Aquila in MISO narrows the advantage of Aquila being in SPP versus MISO from $4.5 M to $2.6 M.

Q. What is the impact of adding estimated trade benefits of $1.9 M to net benefits for Aquila in MISO?

A. First, it should be noted that the trade benefits of Aquila in MISO compared to Aquila standalone are only $0.7 M = $212.4 M (Aquila standalone) - $211.7 M (Aquila in MISO), which are not sufficient to overcome the $1.3 M in 2008 RTO and FERC charges net of savings from not having to provide certain transmission functions at Aquila. [*RTO Cost-Benefit Analysis: Aquila Missouri Electric Operations* (CRA Report), Page 39, Table 15 filed by Aquila as Schedule 3 to Mr. Dennis Odell's direct testimony] The result is a $0.6 M (= $0.7 M - $1.3 M) deficiency in net benefits for Aquila in MISO.

If the estimated trade benefits of $1.9 M are applied against the $0.6 M deficiency, it would appear to make the net benefits of Aquila being in MISO positive, but still not greater than the net benefits from Aquila being in SPP. However, the problem with adding $1.9 M of estimated trade benefits to net benefits for Aquila in MISO and comparing these to Aquila standalone is that maintenance of Aquila's Sibley 3 generation unit in the Aquila standalone case was also scheduled in the fall rather than the spring. Thus, the $1.9 M (or some similar number) would also need to be added to the savings in the Aquila standalone case. The result is that the difference between Aquila in MISO and Aquila standalone remains the same, or essentially the same.

Q. Do you therefore conclude that the CRA cost-benefit analysis performed for MISO demonstrates that the net benefits of Aquila in MISO are negative?

A. While the numerical results indicate a $0.6 M deficiency, it is my expectation that the bias created by using a system-wide dispatch is likely to be greater for Aquila standalone than for Aquila in MISO. This is because, Aquila standalone allows additional units for commitment from all other pools, while Aquila in MISO allows additional units for commitment only from other non-MISO pools, because the units in MISO are already available for unit commitment for Aquila in MISO. Thus, Aquila standalone gains more options through system-wide dispatch than Aquila in MISO.

In addition, the CRA cost-benefit analysis performed for MISO does not include any benefits for improved reliability such as those estimated for Aquila by Mr. Doying. Since Mr. Doying estimates from $4 M to $5.9 M of added benefits, it appears likely that these added benefits would overcome the $0.6 M deficiency shown by the numerical results of the CRA cost-benefit analysis performed for MISO.

C. THE PRICING OF IMPORTS ISSUE

Q. After CRA performed its analysis for MISO incorporating Mr. Pfeifenberger's changes to the analysis CRA performed for Aquila, what other issue did Mr. Pfeifenberger raise regarding CRA modeling?

A. Mr. Pfeifenberger raised as an issue that he calls "rate de-pancaking benefits." [Pfeifenberger Supplemental Direct at pages 10-13]. In this portion of his supplemental rebuttal testimony Mr. Pfeifenberger addressed CRA's treatment of transmission wheeling charges that are added to the market price of imports of energy from outside the pool in which Aquila is located [CRA Report at page 13]. For example, for Aquila standalone this would include all imports into the Aquila control area, adjusted for imports from units in which Aquila participates through either joint ownership or purchased power contracts [CRA Report at page 13]. In the RTO scenarios, the direct interconnections between Aquila and the RTO would also be excluded from these transmission wheeling charges, as there are no wheeling charges for market energy applied within an RTO. This is what has been characterized as one of the rate de-pancaking benefits of being in an RTO.

Q. Is exclusion from transmission wheeling charges a benefit from being in an RTO?

A. Not necessarily. Instead of applying wheeling charges to economy type transactions, both MISO and SPP apply congestion charges for transactions that take place within the pool. Thus, it is not necessarily true that there is a net benefit from substituting one type of charge for the other.

In the CRA model, wheeling charges are placed on transactions that cross pool boundaries as a way of reflecting the costs associated with the dispatch hurdle rates. In particular, for Aquila standalone, these charges reflect the cost of non-firm transmission rates that would be applied to bilateral contracts for energy provided from resources outside of the Aquila standalone pool. As indicated earlier in my testimony, generation from Aquila participation units not located in Aquila's control area are exempted from wheeling charges in all three scenarios (Aquila standalone, Aquila in MISO and Aquila in SPP). For Aquila in an RTO, any purchases by Aquila from the RTO in which it is assumed to participate would also be exempted from wheeling charges. Thus, the purpose of this application of wheeling charges is to ensure that Aquila is not double charged both congestion charges and wheeling charges for the pool in which it is assumed to participate.

Q. What methodology did CRA use for pricing imports?

First, the CRA method for determining the market price for these imports is to price them at the locational marginal price (LMP) of the interchange node. As indicated in the CRA Report, this is a "split savings" approach to account for the differences in LMPs at load versus LMPs at generators supplying energy to load [CRA Report at page 13]. These revenue differences are from congestion (therefore called congestion revenues), and the RTO must refund these congestion revenues to market participants. In this type of cost-benefit study where the utility has no RTO experience with financial transmission rights (FTRs), it is impossible to properly estimate how much of these congestion revenues it is likely to receive from its allocation of FTRs. Thus, the "split savings" approach used by CRA is a credible alternative. From Mr. Pfeifenberger's surrebuttal testimony, it does not appear that he objects to this approach for determining the market price for imports.

Second, as indicated previously in my testimony, if the import is coming from a pool in which Aquila is not participating, the CRA methodology adds a transmission wheeling charge [CRA Report at page 13].

Q. What are some examples of imports where Aquila would have to pay applicable wheeling charges?

A. One example is substitute power purchased when a baseload unit is out for scheduled maintenance. If that power is located outside of the pool in which Aquila is located, Aquila would have to arrange firm point-to-point transmission service to obtain this power to be able to include the unit in Aquila's unit commitment. That firm transmission service would include a transmission charge from the pool within which the substitute power is located; *i.e.*, Aquila would have to pay an additional wheeling charge. Another example is when Aquila is in an RTO and wants to hedge against the market price within the RTO by arranging a bilateral contract with generation outside of the pool. As with the first example, that contract would require some form of point-to-point transmission service and would require Aquila to pay a wheeling charge.

The problem with this second example is that in a production cost model, such as the GE-MAPS model used by CRA, it is nearly impossible to determine ahead of the dispatch what bilateral trades would be advantageous for Aquila to enter into as a hedge against the RTO market price for the pool in which Aquila is located. Thus, CRA's approach to this problem is to identify the tie lines into Aquila, and for imports across those tie lines from entities not in the same pool with Aquila, levy an additional wheeling charge.

Q. What is Mr. Pfeifenberger's objection to CRA's approach?

A. Mr. Pfeifenberger believes that this biases the result in favor of Aquila in SPP and against Aquila in MISO. Specifically, Mr. Pfeifenberger objects to the CRA approach because it applies the wheeling charges to physical flows rather than to contract paths. [Pfeifenberger Supplemental Rebuttal at page 11, lines 3-14]. While Mr. Pfeifenberger states this as a bias against Aquila being in any RTO, he believes this method will result in a greater loss of "rate de-pancking benefits" to Aquila in MISO compared to Aquila in SPP [Pfeifenberger Supplemental Rebuttal at page 12, line 17 to page 13, line 4].

Q. Do you agree with Mr. Pfeifenberger's criticisms of the CRA method of applying wheeling charges to imports?

A. While I understand the difference between contract path and physical flows and agree with Mr. Pfeifenberger that there can be some differences resulting from using physical flows to charge wheeling rates, I believe that the CRA method of applying wheeling charges to imports on tie lines to entities not in the same pool as Aquila is a reasonable approach to dealing with this issue.

More importantly, the CRA approach puts a premium on the number and capacity of tie lines between Aquila and the RTO within which Aquila is assumed to be located. Thus, as indicated in my rebuttal testimony, with fourteen (14) interconnection ties at 5,915 MVA between SPP and Aquila compared to only two (2) interconnection ties at 1,207 MVA between MISO and Aquila, SPP does have an advantage compared to MISO for Aquila avoiding wheeling charges on imports of power. However, I do not consider this to be a bias against the Aquila-in-MISO scenario. Instead, it is one way modeling results can reflect the advantage of one RTO versus another in terms of transmission tie capacity. With respect to the problem of parallel path flows or loop flows (the difference between physical flows and contract path flows), I would also refer the Commission back to my rebuttal testimony where I expressed concern that with the limited number of interconnections between MISO and Aquila, power flows from MISO will very likely run through the AECI transmission system, and absent any flowgate restrictions of MISO's use of AECI's transmission system, I am concerned that Aquila could face a significant number of curtailments from MISO dispatch due to transmission loading relief (TLRs) being called because of thermal overloads. In order to alleviate this concern an estimate of the maximum physical flows from MISO onto the AECI system could be provided along with the impact on the AECI ties to Aquila to determine what flows across the AECI ties to Aquila should not be subject to wheeling charges in the CRA methodology. To be fair, the same should apply to SPP. This adjustment would lower the adjusted production costs for both Aquila-in-MISO and Aquila-in-SPP scenarios relative to Aquila standalone. Without this type of correction, it is difficult to determine whether or not the CRA methodology is biased against one scenario compared to the other.

UNDERSTANDING THE DIFFERENCES: AQUILA IN SPP vs. AQUILA IN MISO

Q. Have you reviewed the analysis CRA performed for MISO to determine the primary differences in results between Aquila in SPP and Aquila in MISO?

A. Yes, I have. Based on this analysis I have reached a conclusion about what I believe to be a significant cause for the differences between Aquila in SPP versus Aquila in MISO:

> ***The economic congestion on the transmission system in and around the Aquila control area is greater when Aquila is in MISO than when Aquila is in SPP.***

Q. What do you mean by "economic congestion" on the transmission system?

A. In simple terms, congestion occurs on a portion of the transmission system at any point where the security limits of that part of the transmission system come into play. For example, transmission lines have ***flow limits*** based on the physical elements of those lines. If a dispatch of generation causes flows to exceed any of these flow limits, that is a violation of a security limit. In RTO dispatch of generation, these limits are placed as constraints on the region-wide dispatch of generation to meet load, and thus, this RTO dispatch is called a ***security constrained economic dispatch***. In a security constrained economic dispatch, congestion on a transmission element occurs whenever a security limit constraint is binding on the dispatch. In essence, binding constraints prevent the dispatch of the most economic (least-cost) generation. Congestion costs per megawatt (price) are then calculated as the decrease in generation costs that would occur if the capacity of the binding transmission element had been increased by one megawatt. This economic calculation of a congestion price can be made by taking the difference in the LMP across the congested transmission element in the direction of the power flow associated with the binding constraint. A higher congestion price implies a greater level of economic congestion on the transmission system. Thus, "economic congestion" not only takes into account physical restrictions on power flows but also the value of these binding constraints in terms of lost savings in generation costs.

Q. What results from these GE-MAPS runs CRA performed for MISO indicated to you a higher level of congestion for Aquila in MISO than for Aquila in SPP?

A. In a discussion with Mr. Pfeifenberger regarding the results from the GE-MAPS model runs he requested from CRA, Mr. Pfeifenberger pointed out a concern that he had not included in his supplemental direct testimony. That concern is the increased generation from the Iatan plant for the Aquila in SPP scenario compared to Aquila in MISO scenario. I analyzed this difference and discovered that Iatan ran at a higher level of output in the Aquila in SPP scenario almost 98% of the time in off-peak hours. Schedule 3 attached to my cross-surrebuttal testimony shows the substitution of greater generation from Iatan versus other generation sources for both on-peak and off-peak periods. On-peak is defined as the hours from 7 a.m. through 10 p.m. on non-holiday weekdays (Monday through Friday). Holidays (New Year's Day, Memorial Day, Independence Day, Labor Day and Christmas Day), weekends (Saturdays and Sundays) and weekdays from 11 p.m. through the 6 a.m. hour are off-peak hours. In addition, I analyzed LMPs for various locations critical to the Aquila control area. The results of the analysis of LMPs are shown on Schedules 4.1 and 4.2 attached to my cross-surrebuttal testimony.

Q. What do your results in Schedule 3 show?

A. In the analysis of Iatan generation, I was concerned with not only the additional generation from the Iatan plant for Aquila in SPP, but also what generation was substituting for Iatan when Aquila was assumed to be in MISO. In order to perform this analysis, I ordered the calculations by having other (non-Iatan) baseload generation not in the Aquila control area (Jeffrey 1, 2 & 3, Gentlemen 1 & 2 and Cooper) being the first substitution, followed by Imports & Exports, Sibley 3, and Peaking generation in Aquila's control area. Initially, I also included the Dogwood unit, but Dogwood generation appears not to be a factor in this analysis as it was rarely committed, and therefore provided only minimal substitution for Iatan generation.

The results show that during periods when Iatan ran at higher levels for Aquila in SPP as compared to Aquila in MISO, Iatan generation (Aquila in SPP) was most often replacing

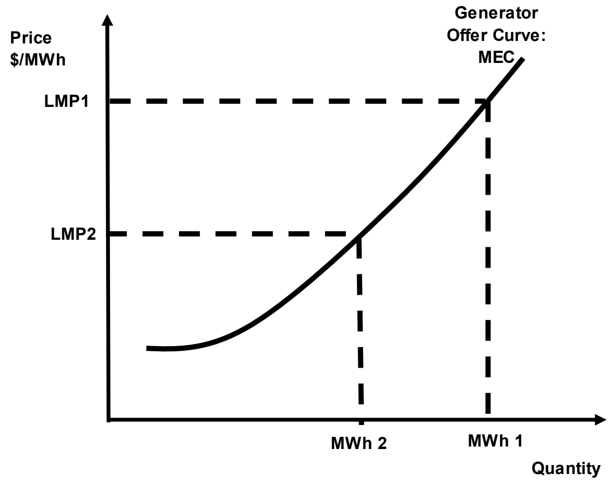
Sibley 3 unit generation (Aquila in MISO) (*i.e.*, just over 43% of the total energy replacing Iatan generation). Imports came in second making up almost 19% of the total energy replaced by Iatan. This is followed by peaking at 15%, other base at 14% and exports at 8.5%. In addition, the percentage of generation replaced by Iatan in the SPP study case in comparison to the MISO study case is in the range of 96.66% to 99.13% during the off-peak period. In total, 97.83% of the generation replaced by Iatan in the SPP study case occurred during the off-peak period, while only 2.17% occurred during the on-peak period.

Initially one might have thought that Iatan, a very low-cost, baseload unit would have been dispatched at its maximum output level in all three scenarios. However, this appears to not be the case for one primary reason: congestion on the transmission system.

Q. How does congestion on the transmission system impact how and when the Iatan generating unit runs?

A. Congestion on the transmission system can restrict the generation of any unit by sending a lower price signal. As the LMP decreases at the generation unit, the amount of generation dispatched from that unit may decrease. This is because, in the GE-MAPS model CRA used, in order for a given level of energy to be dispatched from a unit, the LMP must be at or above that unit's marginal energy cost (MEC) at the level of energy dispatched. With MEC increasing with higher levels of output from a unit, a lowering of the LMP will result in the energy dispatched decreasing to the point where the lower LMP equals MEC. This is shown in figure 1 below where the LMP moves from LMP1 to LMP2 and the output of the unit drops from MWh 1 to MWh 2.

Figure 1: Decrease in Output from a Decrease in Price



Q. How does congestion on the transmission system result in a lower LMP at a generation unit?

A. Think of congestion as preventing a physical flow from a low-cost generator (such as Iatan) to the load (such as Aquila). In this example the generator is upstream of the congestion and the load is downstream of the congestion. If this physical flow is prevented by congestion, then a more expensive generator (one located downstream of the congestion; *e.g.*, Sibley 3) must replace the less expensive generation that is upstream (*e.g.*, Iatan). In order for this to happen, the **LMPs downstream must increase** in order to signal more generation from the more expensive downstream generation, and the **LMPs upstream must decrease** to signal less generation from the less expensive upstream generation. The more restrictive the physical congestion, the greater will be the difference in upstream and downstream LMPs. More restrictive congestion means a larger substitution of higher-cost generation downstream for lower-cost generation upstream.

Q. How does this relate to your analysis of LMPs that is summarized in Schedules 4.a and 4.b?

A. First, in Schedule 4.a are shown the LMPs for various locations within and around Aquila. In the first row of Table 1.A are the LMPs for the three study cases for Aquila load. First notice that these LMPs associated with load are higher than for any of the other generation locations shown in the rows following the first row of Table 1.A. This is shown in Table 1.B where the difference between Load LMPs and Generation LMPs are calculated. This difference in LMPs measures the congestion price between the load and the generator(s). LMPs that are higher at the load than the generators generally indicates that the load is downstream of congestion in comparison to all generation. However, small difference in LMPs may represent losses on the transmission system rather than congestion. In Table 1.B, this may be the case for the locations of: 1) Dogwood unit; 2) Peaking units; and 3) the average LMPs for all generation in the Aquila control area. But losses are not likely to account for the differences in Load LMP compared to: 1) Iatan; 2) Sibley 3; and 3) Aquila's participation units located in MAPP (Mid-Continent Area Power Pool: Gentlemen 1 & 2 and Cooper) and Aquila participation units located in SPP (Iatan and Jeffrey 1, 2 & 3). In each of these cases, the congestion prices are larger than would be associated with just losses.

The results shown in Schedule 4.b look similar to those in Schedule 4.a. The difference is that in Schedule 4.b, hours where there are differences in the scheduled maintenance of the Sibley 3 unit are excluded. I ran this scenario in order to determine if the difference in the scheduled maintenance between the scenarios would change the results in a way that would impact the conclusions that can be drawn from the analysis. It did not.

Q. What conclusions have you drawn from your analysis of LMPs and congestion prices for the three scenarios—Aquila standalone, Aquila in MISO and Aquila in SPP?

A. First, I concluded that there is congestion between generation outside the Aquila control area and the Aquila load, with the generation being upstream of the congestion (lower LMPs) and the load being downstream of the congestion (higher LMPs). This shows in Table 1.B where the largest congestion prices appear on generation outside the Aquila control area (Iatan, Aquila generation in MAPP and Aquila generation in SPP). This characterization of Aquila generation outside of the Aquila control being upstream of congestion to load downstream of congestion is consistent during both on-peak and off-peak hours, with the congestion prices being higher during the on-peak than during the off-peak.

Second, in Tables 2.A and 2.B the differences in LMPs for Aquila in MISO versus Aquila in SPP show a greater degree of upstream congestion. This occurs for two reasons: 1) the Load LMP for Aquila in MISO is higher; and 2) the upstream generator LMPs for Aquila in MISO are lower. Both of these are characteristics of greater levels of congestion for Aquila in MISO compared to Aquila in SPP. Also notice in Table 2.B that this difference is particularly strong for Iatan and Aquila generation in SPP (see the bolded and shaded cells in Table 2.B). In particular, the congestion price between Iatan and Aquila's load is higher during the off-peak period than during the on-peak period. Thus, higher congestion between Iatan and Aquila's load for Aquila in MISO compared to Aquila in SPP is a primary determinate for the substitution of higher-cost energy from generation within the Aquila control area for lower-cost energy from Iatan when Aquila is in MISO compared to Aquila in SPP.

Q. What is the cause of this higher congestion between Iatan and Aquila load for Aquila in MISO compared to Aquila in SPP?

A. First, it does not appear that Iatan or Aquila's other generation units in SPP or MAPP are committed differently depending on whether Aquila is in MISO or Aquila is in SPP. Thus, differences in unit commitment do not appear to be driving the differences in congestion between the two scenarios.

Second, in the GE-MAPS model, the dispatch of generation is system wide, but in order for generation inside one pool to meet load within another pool (*e.g.*, an export from pool A as an import to pool B), the cost of the generation being exported from pool A, including the cost of the dispatch hurdle rate, must be cheaper than generation being backed down in pool B. Thus, when Aquila is in SPP, generation from MISO can be used to meet SPP/Aquila load, and when Aquila is in MISO, generation from SPP can be used to meet MISO/Aquila load, but the costs are differentiated between scenarios through the change in the application of the dispatch hurdle rates. Otherwise, the dispatch of generation would be identical for Aquila in MISO and Aquila in SPP.

When the dispatch of generation changes, power flows also change and this provides the primary basis for the differences in congestion between the two scenarios. But, this only explains that different dispatches will result in different congestion patterns. It does not explain why congestion is stronger in one scenario (Aquila in MISO) than the other (Aquila in SPP).

Third, because of hurdle rates for non-participation generation in SPP, when Aquila is in MISO, the economics will be to dispatch more generation from MISO to meet Aquila's load than when Aquila is in SPP. Because of the greater limitations of the east to west transmission system for imports into Aquila's control area it is likely that the dispatch associated with Aquila in MISO congests transmission into Aquila's control area more than the dispatch associated with Aquila in SPP. When this occurs, in order to meet Aquila's load, more internal generation will be dispatched, raising LMPs internal to Aquila's control area (e.g., Sibley 3 and Peaking), and less generation will be dispatched from generation sources external to Aquila's control area (e.g., Iatan), lowering LMPs at these generation sources.

CONCLUSIONS REGARDING MISO REBUTTAL AND SUPPLEMENTAL REBUTTAL TESTIMONY

Q. Have the rebuttal and supplemental rebuttal testimonies filed by MISO's witnesses, as well as your review of their work papers and MISO data request responses caused you to change Staff's recommendation to the Commission that it should not grant Aquila's application to join the Midwest ISO?

A. No, it has not. While the information Mr. Doying and Mr. Pfeifenberger present on behalf of MISO lead me to believe that while it may be cost beneficial for Aquila to join MISO compared to standalone, they have not shown that it is more beneficial for Aquila to join MISO than SPP. In summary, even with the adjustment made for scheduled outages of the Sibley 3 plant, Aquila in SPP shows greater net benefits than Aquila in MISO. This appears to be driven by the greater level of congestion for meeting Aquila's load from Aquila's participation generation located outside Aquila's control area when Aquila is in MISO compared to Aquila in SPP. The dispatch of this low-cost generation for meeting Aquila's load appears to be a primary driver in determining which RTO provides the greater benefits to Aquila. Therefore, I cannot recommend to the Commission that Aquila joining MISO is not detrimental to the public interest.

CROSS-SURREBUTTAL OF CITY OF INDEPENDENCE REBUTTAL

Q. What position does the City of Independence take regarding Aquila joining MISO?

A. The position of the City Independence supporting Aquila joining MISO is set out in the rebuttal testimony of Paul N. Mahlberg (Planning and Rates Supervisor for Independence Power & Light Department) and Mark J. Volpe (Consultant with Jennings, Strouss and Salmon PLC).

Mr. Mahlberg describes the electric operations of the City of Independence, including its interconnections and power supply arrangements. In addition, Mr. Mahlberg recommends the Commission authorize Aquila to join MISO because he believes that it will give the City of Independence “access to a fully developed market for sales and purchases” of electricity. In addition, Mr. Mahlberg believes that because MISO is a larger geographic region than SPP, the City of Independence would have access to greater power supply resources with Aquila in MISO than with Aquila in SPP. Finally, Mr. Mahlberg seems to infer that Aquila needs to be a member of MISO in order to transmit power from and to anywhere in the entire MISO/PJM region without incurring pancaked transmission rates.

Mr. Volpe supports the testimony of Mr. Mahlberg with respect to greater geographic access to sales and purchases of electricity and benefits from non-pancaked transmission rates. Then, Mr. Volpe addresses two issues related to the cost-benefit analysis CRA performed for Aquila. The first is the assumption made by CRA that the administrative costs in SPP are the same as in MISO. The second is the assumption that the SPP and MISO markets are the same.

Q. Do you agree with any of the points raised by City of Independence witnesses in their rebuttal testimony?

A. I agree that MISO is a larger geographic region than SPP, that MISO currently has markets for day-ahead energy that SPP does not have and that MISO is further along in developing markets for regulation and operating reserves than SPP.

Q. Do you agree that being in an RTO with a larger geographic region gives Aquila and the City of Independence greater access to sell and buy electricity?

A. No, I do not. Access to sell and buy electricity is based on the availability of transmission capacity. With limited interconnections between Aquila and MISO, it is doubtful that Aquila would have greater access to sell and buy electricity by being in MISO compared to being in SPP. In fact, with respect to economy transactions, access to sell and buy electricity is a major reason for running the cost-benefit analysis to determine how spot-market transactions would differ for Aquila from being in MISO compared to being in SPP. As indicated earlier in my cross-surrebuttal testimony, Aquila has greater access (reduced congestion) to lower-cost generation in the SPP energy markets than it would from participation in the MISO energy markets.

Q. Is your answer limited to economy transactions in the day-to-day spot markets long-term contracts for power supply?

A. No. It also includes long-term contracts for power supply, but from a different perspective. In MISO, the City of Independence could designate any network resource located MISO as its network resource without incurring transmission upgrade costs. However, a network resource in MISO simply means that it is deliverable to the MISO energy market and does not mean that it is deliverable to the City of Independence without congestion cost payments. In order to hedge against congestion costs from a designated network resource to the utility's load, the City of Independence would have to acquire annual

FTRs from that generation source to its load. The problem that the City of Independence would face is that in MISO long-term transmission rights have first call in the allocation of FTRs, and long-term transmission rights are based on historical rights that were in effect prior to the start of the MISO markets. Thus, it is highly unlikely that the City of Independence or any other utility requesting FTRs from MISO for new generation sources will be able to obtain these rights without paying for upgrades to the transmission system required to provide the transmission capability necessary to meet what MISO calls its simultaneous feasibility test for allocating FTRs. The simultaneous feasibility test restricts the allocation of FTRs to load flows that would meet all of the transmission constraints of the power system when the megawatts of FTRs are simultaneously run through a power flow model as if they were physical transactions from the specified generation sources to the specified load destinations. With other long-term transmission rights having priority, this means that requests for new transactions would have to be feasible assuming that all the FTRs with priority are already on the power grid decreasing the transmission capability available to new requests for FTRs.

The impact of this system of FTRs with respect to greater geographic region is that the further the generation resource is located from the load, the more likely it becomes that transmission upgrades will be required to grant a new request for FTRs. The City of Independence would then have to estimate the cost of congestion payments and compare it to the cost of the required upgrades in order to determine which option to take for a new resource located in MISO. Estimating congestion payments over a long period of time (life of the long-term contract) can be a daunting task. In addition, while the City of Independence would not have to pay an additional transmission rate (elimination of rate pancaking), it would either have to pay additional congestion costs or pay for transmission upgrades required to provide it with FTRs from its new generation source to its load. As I stated previously in my testimony, it is not clear that this will result in a net benefit to the City of Independence.

Q. How does MISO's and SPP's approaches for designating new generation resources compare?

A. SPP uses an aggregate study process to determine what transmission upgrades are required to deliver the power from the new designated resource to the load. In the aggregate study the costs of the transmission upgrades required to meet all of the requests for transmission service are allocated to all the requests for new transmission service based on each requests' megawatt impacts on the transmission upgrades. Then, the costs of the transmission upgrades allocated to each request are assigned either to what SPP calls "Base Plan Funding" (BPF) or to the utility making the request. In most cases, a majority of the costs of the transmission upgrades are assigned to BPF, where one-third of the costs are assigned to a region-wide postage stamp rate and the remaining two-thirds are allocated to various utilities based on their positive MW-mile impacts from the transmission upgrades. The concept here is that transmission upgrades provide benefits to all transmission customers located near the upgrade by allowing their existing transmission facilities to become less loaded thereby increasing transmission transfer capability and reducing congestion on the transmission system. While the transmission zone in which the requesting entity is located will be allocated additional costs through the BPF process, the requestor will only be directly assigned transmission upgrade costs if its request violates one or more of the safe-harbor conditions: 1) Five-year or greater contract; 2) Not to exceed 125% reserve margin; and 3) Not to exceed a $180,000/MW total upgrade cost. Even if one of these conditions is violated, the requestor can ask for a waiver from the SPP Board of Directors. Several such waivers have been granted in the past.

In contrast for MISO, the requestor would have to pay the full cost of the upgrades necessary to receive the FTRs; there would be no aggregate study process where others could directly be allocated some of the costs of the upgrades; and there would be no BPF process for rolling the cost of the upgrades into rates, even though other entities would benefit from those upgrades. Finally, when a portion of the costs are directly assigned to the requestor, the SPP tariff allows for revenue credits from subsequent new users of the upgrades to be paid to the entity that was directly assigned all or a portion of the cost of the upgrade. The concept here is that those who benefit from the upgrades in the future should help to reduce the costs directly assigned to the entity that caused the upgrade to be built by being the first to make the request. This revenue crediting applies to both point-to-point and network service use of the upgrade transmission facilities. MISO does not have a similar tariff provision related to upgrades required for requests for new FTRs.

Q. Based on the two different systems used for transmission service related to new designated resources, what is your conclusion regarding the impact of a larger geographic area on access to generation resources?

A. I find the SPP approach to better reflect a beneficiary pays approach to pricing transmission, while the MISO approach depends heavily on a cost causer pays approach. In addition, in almost all instances, I believe that the City of Independence will have lower-cost access to generation in SPP than it would in MISO. The problem is that the further away the resource is located in MISO, the more likely the City of Independence is to incur significant congestion costs, or in the alternative, bear the cost of directly assigned transmission upgrades in order to mitigate those costs. Therefore, I find MISO being a larger geographic region than SPP provides little, if any, additional benefits to the City of Independence in terms of access to new designated resources.

Q. But, doesn't being in MISO provide benefits for making transactions in MISO at non-pancaked transmission rates?

A. The transmission rate benefits of being in MISO apply to bilateral transactions that the City of Independence might enter into on a point-to-point basis. If point-to-point transmission service is available in MISO, then the City of Independence could enter into a purchase of energy (and perhaps capacity that would require firm transmission service) that would be deliverable to its load destination absent any congestion charges. This is a physical hedge against having to pay the MISO market price for this same energy. This bilateral transaction could be located within MISO or PJM, in which case the transmission customer would pay only a single transmission rate – the rate of the zone designated as the destination. This bilateral transaction could be located outside of MISO or PJM, in which case the transmission customer would pay any additional transmission charges to have the power delivered to MISO.

In contrast, while transmission customers not located in MISO would only pay a single transmission rate to MISO, called an "out" rate, they would also incur transmission costs from the transmission system providing service to the transmission customer's destination. For example, if Aquila is in SPP, then the City of Independence would pay the MISO rate plus the SPP rate for Aquila to deliver power from MISO. Thus, Aquila being in MISO would eliminate the additional charge for Aquila's transmission rate to the City of Independence. However, Aquila being in MISO would add an additional transmission charge to the City of Independence for a point-to-point transaction from a generator located in SPP. The question then becomes, from which of these two entities will the City of Independence most likely find available point-to-point transmission service that will allow it to enter into these transactions? The answer to this question has nothing to do with the size of the geographic region of the RTO, but is more likely to be determined by the number of interconnections between Aquila and the two RTOs. In this regard, the cost-benefit analysis run by MISO can provide some insight. While the study looks at power flows based on economics rather than the availability of point-to-point transmission service over contract paths, the level of congestion into Aquila from economic based power flows do provide a sense of what is likely to happen to the availability of point-to-point transmission rights.

In brief, higher levels of congestion from economic based power flows from the RTO spot markets suggest a lower level of availability of point-to-point transmission rights for contract path arrangements. Moreover, if the RTO market prices indicate a certain price at which a supplier can sell to the market, that supplier is unlikely to take a much lower price in a bilateral contract. In fact, by entering into a bilateral contract the supplier is wanting to hedge against lower market prices. Thus, there should be some convergence in price between the bilateral markets and the RTO spot markets. This price convergence means that the congestion in the economic based power flows is likely to converge to or be reflective of the availability of point-to-point transmission rights for bilateral contracts.

Q. Do you agree with Mr. Volpe that the MISO and SPP electricity markets differ?

A. As indicated in my rebuttal testimony, I agree there is a difference. However, as I also discussed in my rebuttal testimony, I do not believe that this difference is one that should be used as the basis for the Commission making a decision in this case. In addition, I believe that Mr. Volpe's rebuttal testimony does not present a correct characterization of these differences.

Q. Where do you believe Mr. Volpe's characterization of the differences between the MISO and SPP electricity markets is wrong?

A. The characterization of the differences that starts at line 17 of page 6 of Mr. Volpe's rebuttal testimony and carries over to page 7 ending at line 14 is misleading. For example, Mr. Volpe states: "The major difference between the SPP model and the Midwest ISO's market is that there is no financially binding Day-Ahead market within SPP's market design and the majority of the transactions in SPP occur on a bilateral basis because there is no centrally administered market as there is in the Midwest ISO." [Volpe Rebuttal: line 23, page 6 to line 4, page 7]. While the first part of Mr. Volpe's statement is correct regarding the lack of a financially binding Day-Ahead market in SPP, the second part of his statement regarding the majority of the transactions in SPP occurring on a bilateral basis is not correct.

In SPP, bilateral transactions are the basis for day-ahead unit commitment; while in MISO day-ahead unit commitment is based on bids submitted by market participants that MISO uses to determine the day-ahead unit commitment as well as a day-ahead dispatch of generation from the units that are committed. In SPP, the day-ahead dispatch is called a schedule, and each load-serving entity must schedule sufficient generation to meets its load. However, these schedules are not financially binding. Moreover, subsequent to day-ahead unit commitment, generation is bid into the SPP real-time imbalance market, but the objective here is not simply to provide for differences from what was scheduled day-ahead. The objective is to perform a centrally-dispatched, least-cost solution based on the bids and the transmission constraints on the SPP transmission system. The SPP external market monitor reports in his December 17, 2007 assessment that: "In the first seven months, participation was consistently at a robust level; on average, 80% of capacity was made available for dispatch in the EIS Market." (Note: EIS stands for Energy Imbalance Services) What this means is that while market participants can decide whether to self-dispatch their resources or to participate fully in the market by making their resources available for SPP to dispatch on a least-cost basis, 80% of those resources chose the SPP market route rather than the self-dispatch route. Thus, the majority of transactions in SPP do not occur on a bilateral basis, and there certainly is a centrally administered market in SPP.

Q. Could the second part of Mr. Volpe's statement have been meant to only apply to Day-Ahead energy markets?

A. If Mr. Volpe meant only to refer to day-ahead energy markets in his statements, he should have modified the statement to read "all (not the majority of) day-ahead transactions in SPP occur on a bilateral basis because there is no day-ahead (not centrally) administered market as there is in the Midwest ISO." Whether or not a day-ahead market provides SPP with additional benefits that exceed the costs of administering a day-ahead market is the subject matter for a cost-benefit study that SPP will have performed this year. Mr. Greg Meyer of the Commission Staff is serving on the cost-benefit task force, and it is my understanding that the Response for Bids was sent out at the end of January 2008, with the expectation that the cost-benefit study would be completed by September 2008. Once the cost-benefit analysis is completed, the SPP will have a better estimate of both the costs and the benefits associated with a day-ahead market. It is not clear at this point in time that a system of bilateral trades for day-ahead unit commitment along with an 80% participation rate for generators bidding into the market does not produce a lower cost solution. If that is the case, then the CRA cost-benefit analysis underestimates the benefit from Aquila being in SPP.

Q. Do you have other concerns with Mr. Volpe's characterization of the SPP energy markets?

A. Mr. Volpe further states: "SPP thus still utilizes TLRs to address congestion, rather than the Midwest ISO's use of congestion charges based on locational marginal pricing and FTRs to enable hedging against congestion charges." [Volpe Rebuttal; page 7, lines 6 to 9]. The only thing true about this statement is the fact that SPP has something called transmission line relief (TLR), but it does not use TLRs as the sole or even primary means of addressing congestion. This same incorrect information about SPP is conveyed by Mr. Volpe's answer on page 9, lines 12-19.

First, SPP does use locational marginal pricing in its real-time dispatch of the energy imbalance market. Second, TLRs are not used as a primary tool to manage congestion in SPP. Third, SPP has a form of FTRs that enable market participants to hedge against congestion charges in the real-time, energy imbalance market.

Q. What is the form of locational marginal prices used in the SPP?

A. It is identical to the locational marginal prices used in MISO, except for the pricing of losses. SPP uses an average loss calculation rather than the marginal loss calculation used in MISO. MISO prices losses at the marginal cost of generation to supply losses and then refunds the difference between marginal and average losses to its customers.

Q. What is the primary tool SPP uses to manage congestion?

A. Identical to MISO, SPP uses a centralized dispatch of generation at least-cost based on the offers and bids of market participants. This is called a "securitized" dispatch of generation because it is subject to the transmission constraints on the SPP transmission grid as well as the constraints on the transmission grids of its neighbors. By honoring these transmission constraints in its dispatch, SPP is managing congestion on its system based on economics (reflected by offers and bids) rather than by administrative allocations that are associated with transmission line relief (TLR). Moreover, SPP manages congestion in the same way that MISO manages congestion.

Q. Does SPP use TLRs for managing congestion?

A. Yes, it does. However, this is minor portion of congestion management in SPP, just as it is in MISO. TLRs are used to manage congestion from physical transmission schedules when they overload the system. Both MISO and SPP have physical transmission schedules that are submitted and approved by each RTO. When transmission service is less than what the RTO expected, for example, due to a transmission line going out of service, a generator going out of service or unexpected loop flows from neighbors, these transmission schedules may have to be curtailed. TLRs are used for these curtailments that are based on priority of service and are applied on a pro rata (not economic) basis.

Q. What hedges against congestion are available to SPP customers?

A. In the day-ahead unit commitment, schedules are submitted to SPP for it to make a determination of whether or not these schedules are simultaneously feasible. If they are not, then SPP issues a TLR, and submitted schedules that impact the over-loaded transmission elements are backed down on a pro-rata basis. The utilities must then redispatch their schedules in order to provide SPP with a day-ahead schedule that will meet their forecasted loads that do not over load the transmission system. The importance to the utility of these day-ahead schedules is two-fold: 1) it determines their unit commitments for the next day; and 2) it determines the sources and amounts of generation from those sources for which it does not have to pay congestion costs. A similar simultaneous feasibility is run by MISO to determine the allocation of FTRs; the difference is that SPP's allocation changes each day, while MISO's allocation is in place for an entire season. In this sense, the SPP approach provides greater flexibility to the transmission customer that will more closely match the physical transmission rights they have as transmission customers.

It should also be pointed out that in SPP day-ahead schedules can be modified up to one hour ahead of the SPP security constrained economic dispatch. This allows market participants sufficient time to enter into different bilateral agreements, particularly when a previous transaction has been curtailed.

Q. Do you agree with the adjustments that Mr. Volpe makes to the CRA results to account for market differences?

A. No, I do not. Mr. Volpe simply takes the difference between the SPP trade benefits and the MISO trade benefits and subtracts that difference from the SPP trade benefits for the years 2008 through 2010. Mr. Volpe gives no explanation of why this calculation would provide a fair measure of the difference in the markets between the two. For example, Mr. Pfeifenberger's approach to this same issue was to place a small hurdle rate on transactions that occur within SPP. Even with all the other changes made by Mr. Pfeifenberger, his results still had Aquila in SPP with higher trade benefits than Aquila in MISO. Thus, there is no support for the type of adjustment Mr. Volpe proposes.

Q. Do you agree with Mr. Volpe regarding the differences in administrative costs between SPP and MISO?

A. No, I do not. Mr. Volpe characterizes the fact that the CRA cost-benefit analysis used the same administrative costs for Aquila in SPP and Aquila in MISO as a flawed assumption. This assumption was agreed to by all the parties prior to CRA running the study. As I explained in my rebuttal testimony, this is a reasonable assumption to make compared to attempting to estimate the administrative costs of SPP and MISO.

Q. What is Mr. Volpe's reasoning that using the same administrative costs for Aquila in SPP and Aquila in MISO is a flawed assumption?

A. Mr. Volpe argues that since the administrative costs are "fixed costs," and since SPP will be collecting these fixed costs over fewer participants, the SPP costs should have been higher. For several reasons, I do not agree with Mr. Volpe's argument.

First, the costs of implementing a market are capital costs, and therefore do not vary with megawatt-hours sold in the SPP market; *i.e.*, these are fixed costs. But being a fixed cost has nothing to do with whether the annualized costs applied to customers will be higher or lower with larger versus smaller market sizes.

Second, what Mr. Volpe may have meant with respect to "fixed costs" is that a model of the cost of implementing electricity markets would contain ***lumpy*** investments. Thus, over certain ranges of market sizes, the costs are relatively fixed, but once you hit a critical size level, the costs jump up and stay relatively constant until you hit the next critical size level. For example, these critical size levels could be determined by computer capacities as well as the degree of sophistication that needs to be built into the software programs used for security constrained economic dispatch. Thus the total cost as a function of market size might look like a stair step, with the cost going up at each critical size level. But this stair-step model of lumpy costs provides no useful information regarding whether or not the unit costs for a smaller market would be higher or lower than the unit costs for a larger market unless you can determine that the smaller market is just above a critical level where a jump in cost has occurred and the larger market is below the next critical level. If this is what Mr. Volpe is inferring, then he has failed to provide anything showing that SPP and MISO can be considered to be on the same step of the stair-step model of lumpy costs.

Q. Is there any other economic model that might infer lower per unit costs for larger market size?

A. Yes. Mr. Volpe might have simply meant to say that he believes there are economies of scale associated with the implementation of markets. What this means is that the per unit cost of implementing a market decreases with the size of the market that would likely be measured by the number of sources (generator locations), sinks (load locations) and interchanges in the market. However, Mr. Volpe provides no support that this is the case, or even likely to be the case.

Q. Should the Commission put significant weight on either the stair-step cost model or economies of scale theory in its evaluation of the assumption made in the CRA study that administrative costs are the same for Aquila in MISO versus Aquila in SPP?

A. No. Both stair-step cost models and models involving economies of scale pale in significance to the fact that MISO is: 1) the first RTO to implement a market that covers a geographic scope of fourteen states plus a Canadian province (scale); and 2) an RTO that includes provisions for a "swiss-cheese" membership in the Mid-America Power Pool (MAPP) region (scope). Moreover, there are institutional (first to implement) and scope issues (configuration of the market) that can result in higher costs.

First, to cover the scale involved in the MISO market required an entirely new set of software programs that could effectively deal with significantly more generation and load busses than had ever before been contemplated. Second, the more non-standard the market scope is, the more individualized programming must be built into the market design. Because of this, it is impossible to use theoretical cost models that assume everything else is the same as the basis for evaluating SPP's administrative costs compared to MISO administrative costs. Therefore, the Commission should put very little weight on Mr. Volpe's testimony regarding SPP being likely to have higher administrative costs than MISO.

Q. Does this complete your cross-surrebuttal testimony?

A. Yes, it does.

Aquila in SPP vs Aquila in MISO:
Subtitution of Iatan Generation for Other

Data from Supplemental CRA Runs via MISO

Other	On-Peak		Off-Peak		Total	
	MWh	%	MWh	%	MWh	%
Base	83	0.87%	9,474	99.13%	9,557	14.27%
Imports	414	3.26%	12,284	96.74%	12,697	18.96%
Export	296	5.20%	5,395	94.80%	5,691	8.50%
Sibley 3	324	1.12%	28,605	98.88%	28,929	43.19%
Peaking	337	3.34%	9,764	96.66%	10,101	15.08%
Total	1,454	2.17%	65,521	97.83%	66,975	100.00%

LMP Comparisons for 2008: MISO Supplemental Model Runs

Table 1.A: LMP Comparisons by Study Pool

	All Hours			On-Peak			Off-Peak		
Location	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**
Aquila Load	$39.26	$38.99	$37.96	$48.20	$47.85	$47.17	$31.39	$31.19	$29.85
Iatan	$32.76	$32.66	$35.13	$41.63	$41.45	$44.18	$24.96	$24.92	$27.17
Sibley 3	$35.96	$35.79	$35.27	$44.51	$44.17	$44.16	$28.43	$28.41	$27.44
Dogwood	$36.62	$39.10	$36.62	$45.33	$47.35	$45.33	$28.95	$31.84	$28.95
Peaking	$38.01	$37.89	$36.69	$46.81	$46.57	$45.79	$30.26	$30.24	$28.67
Aquila Gen in Aquila CA	$37.98	$37.90	$36.63	$46.71	$46.54	$45.70	$30.30	$30.30	$28.65
Aquila Gen in MAPP	$27.07	$27.15	$27.21	$31.82	$32.09	$31.97	$22.88	$22.81	$23.02
Aquila Gen in SPP	$33.51	$33.39	$35.06	$42.11	$41.93	$43.99	$25.95	$25.87	$27.20

Table 1.B: Congestion Prices by Study Pool

	All Hours			On-Peak			Off-Peak		
Load LMP minus:	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**
Iatan	$6.50	$6.33	$2.83	$6.57	$6.40	$2.99	$6.43	$6.27	$2.68
Sibley 3	$3.30	$3.20	$2.69	$3.69	$3.67	$3.01	$2.95	$2.77	$2.41
Dogwood	$2.64	-$0.12	$1.34	$2.87	$0.50	$1.84	$2.44	-$0.65	$0.91
Peaking	$1.25	$1.10	$1.27	$1.38	$1.28	$1.38	$1.12	$0.95	$1.18
Aquila Gen in Aquila CA	$1.27	$1.09	$1.33	$1.49	$1.31	$1.48	$1.09	$0.89	$1.20
Aquila Gen in MAPP	$12.19	$11.84	$10.75	$16.38	$15.76	$15.20	$8.50	$8.38	$6.83
Aquila Gen in SPP	$5.74	$5.60	$2.90	$6.09	$5.92	$3.19	$5.44	$5.32	$2.66

Table 2.A: LMP Differences by Study Pool

	All Hours			On Peak			Off-Peak		
Location	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**
Aquila Load	-$0.27	-$1.30	-$1.03	-$0.35	-$1.03	-$0.67	-$0.20	-$1.53	-$1.34
Iatan	-$0.10	$2.37	$2.48	-$0.18	$2.55	$2.73	-$0.04	$2.22	$2.25
Sibley 3	-$0.17	-$0.69	-$0.52	-$0.34	-$0.35	-$0.01	-$0.02	-$0.99	-$0.97
Dogwood	$2.48	$0.00	-$2.48	$2.02	$0.00	-$2.02	$2.89	$0.00	-$2.89
Peaking	-$0.13	-$1.32	-$1.20	-$0.25	-$1.02	-$0.77	-$0.02	-$1.59	-$1.57
Aquila Gen in Aquila CA	-$0.08	-$1.35	-$1.27	-$0.17	-$1.01	-$0.84	$0.00	-$1.65	-$1.65
Aquila Gen in MAPP	$0.08	$0.14	$0.06	$0.26	$0.15	-$0.12	-$0.07	$0.14	$0.21
Aquila Gen in SPP	-$0.13	$1.54	$1.67	-$0.18	$1.87	$2.06	-$0.08	$1.25	$1.32

Table 2.B: Congestion Price Differences by Study Pool

	All Hours			On Peak			Off-Peak		
Load LMP minus:	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**
Iatan	-$0.17	-$3.67	**-$3.50**	-$0.17	-$3.58	**-$3.41**	-$0.16	-$3.75	**-$3.59**
Sibley 3	-$0.10	-$0.61	-$0.51	-$0.01	-$0.68	-$0.67	-$0.18	-$0.54	-$0.36
Dogwood	-$2.75	-$1.30	$1.46	-$2.37	-$1.03	$1.34	-$3.09	-$1.53	$1.56
Peaking	-$0.14	$0.03	$0.17	-$0.11	-$0.01	$0.10	-$0.18	$0.06	$0.23
Aquila Gen in Aquila CA	-$0.19	$0.06	$0.24	-$0.18	-$0.01	$0.16	-$0.19	$0.12	$0.31
Aquila Gen in MAPP	-$0.35	-$1.44	-$1.08	-$0.62	-$1.17	-$0.56	-$0.12	-$1.67	-$1.55
Aquila Gen in SPP	-$0.14	-$2.84	**-$2.69**	-$0.17	-$2.90	**-$2.73**	-$0.12	-$2.78	**-$2.66**

Schedule 4.1

LMP Comparisons for 2008: Hours Without Sibley Maintenance

Table 1.A: LMP Comparisons by Study Pool

	All Hours			On-Peak			Off-Peak		
Location	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**
Aquila Load	$39.87	$39.70	$38.51	$49.26	$49.14	$48.07	$31.96	$31.75	$30.41
Iatan	$32.84	$32.87	$35.52	$42.04	$42.15	$44.88	$25.08	$25.04	$27.59
Sibley 3	$36.39	$36.27	$35.68	$45.41	$45.25	$44.96	$28.79	$28.71	$27.82
Dogwood	$37.02	$39.72	$37.02	$45.99	$48.49	$45.99	$29.42	$32.34	$29.42
Peaking	$38.61	$38.58	$37.20	$47.86	$47.84	$46.65	$30.82	$30.78	$29.20
Aquila Gen in Aquila CA	$38.57	$38.58	$37.13	$47.74	$47.79	$46.53	$30.85	$30.82	$29.16
Aquila Gen in MAPP	$27.64	$26.76	$27.82	$32.69	$31.86	$32.88	$23.40	$22.46	$23.54
Aquila Gen in SPP	$33.60	$33.65	$35.37	$42.56	$42.68	$44.62	$26.05	$26.04	$27.53

Table 1.B: Congestion Prices by Study Pool

	All Hours			On-Peak			Off-Peak		
Load LMP minus:	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**	**S-A**	**MISO**	**SPP**
Iatan	$7.03	$6.83	$2.99	$7.23	$6.98	$3.18	$6.88	$6.72	$2.82
Sibley 3	$3.48	$3.43	$2.83	$3.85	$3.89	$3.11	$3.18	$3.04	$2.59
Dogwood	$2.85	-$0.02	$1.49	$3.28	$0.65	$2.08	$2.55	-$0.59	$1.00
Peaking	$1.26	$1.12	$1.31	$1.40	$1.30	$1.42	$1.14	$0.97	$1.22
Aquila Gen in Aquila CA	$1.30	$1.12	$1.38	$1.52	$1.35	$1.53	$1.11	$0.93	$1.25
Aquila Gen in MAPP	$12.23	$12.94	$10.69	$16.58	$17.27	$15.19	$8.56	$9.29	$6.87
Aquila Gen in SPP	$6.27	$6.05	$3.14	$6.71	$6.46	$3.45	$5.91	$5.72	$2.88

Table 2.A: LMP Differences by Study Pool

	All Hours			On Peak			Off-Peak		
Location	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**
Aquila Load	-$0.17	-$1.36	-$1.19	-$0.13	-$1.20	-$1.07	-$0.21	-$1.55	-$1.34
Iatan	$0.03	$2.69	$2.66	$0.11	$2.85	$2.73	-$0.05	$2.51	$2.56
Sibley 3	-$0.11	-$0.70	-$0.59	-$0.17	-$0.46	-$0.29	-$0.08	-$0.97	-$0.89
Dogwood	$2.70	$0.00	-$2.70	$2.50	$0.00	-$2.50	$2.92	$0.00	-$2.92
Peaking	-$0.03	-$1.41	-$1.38	-$0.02	-$1.21	-$1.19	-$0.04	-$1.63	-$1.59
Aquila Gen in Aquila CA	$0.01	-$1.44	-$1.45	$0.04	-$1.21	-$1.25	-$0.03	-$1.69	-$1.66
Aquila Gen in MAPP	-$0.87	$0.18	$1.06	-$0.82	$0.19	$1.01	-$0.93	$0.14	$1.07
Aquila Gen in SPP	$0.05	$1.77	$1.72	$0.12	$2.06	$1.94	-$0.01	$1.48	$1.49

Table 2.B: Congestion Price Differences by Study Pool

	All Hours			On Peak			Off-Peak		
Load LMP minus:	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**	**MISO-SA**	**SPP-SA**	**SPP-MISO**
Iatan	-$0.20	-$4.05	**-$3.85**	-$0.24	-$4.04	**-$3.80**	-$0.16	-$4.06	**-$3.90**
Sibley 3	-$0.05	-$0.65	-$0.60	$0.04	-$0.74	-$0.78	-$0.13	-$0.58	-$0.45
Dogwood	-$2.87	-$1.36	$1.51	-$2.63	-$1.20	$1.43	-$3.13	-$1.55	$1.58
Peaking	-$0.14	$0.05	$0.19	-$0.11	$0.01	$0.12	-$0.17	$0.08	$0.25
Aquila Gen in Aquila CA	-$0.18	$0.08	$0.26	-$0.17	$0.01	$0.19	-$0.18	$0.14	$0.32
Aquila Gen in MAPP	$0.71	-$1.54	-$2.25	$0.69	-$1.39	-$2.08	$0.72	-$1.69	-$2.41
Aquila Gen in SPP	-$0.22	-$3.13	**-$2.91**	-$0.25	-$3.26	**-$3.01**	-$0.20	-$3.03	**-$2.83**

Schedule 4.2