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Cost-Benefit Analysis of the Participation In Regional Transmission Organizations By the Missouri Operating Companies of Aquila

Prepared for

The Midwest Independent Transmission System Operator

By

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I. Executive Summary

This study analyzes the economic impacts, risks, and opportunities for Aquila's Missouri operating companies, Missouri Public Service Company and St. Joseph Power & Light Company, (hereafter Aquila-MO) transferring operation of their transmission system to a Regional Transmission Organization (RTO): the Midwest Independent Transmission System Operator (Midwest ISO) or the Southwest Power Pool (SPP), or alternatively operating their transmission on a stand alone basis outside of both the SPP and the Midwest ISO energy markets.

The Midwest ISO operates more than 97,000 circuit miles of transmission facilities for 28 member transmission owners in a region that includes most of Missouri and parts of 14 other states as well as the province of Manitoba. The Midwest ISO also provides independent tariff administration and transmission planning services for Duke Power with an additional 13,000 miles of transmission lines in North and South Carolina. SPP serves member companies in 7 states including portions of western Missouri, as well as Oklahoma and parts of Arkansas, Kansas, Louisiana, New Mexico, and Texas. SPP's members operate 52,000 circuit miles of transmission facilities.

The two Regional Transmission Organizations (RTOs) offer different services. The Midwest ISO has implemented a Transmission and Energy Markets Tariff (TEMT) under which it provides regional security-constrained unit commitment and economic dispatch. It operates Day-Ahead and Real-Time Energy Markets. And, it has implemented a system of Financial Transmission Rights (FTRs) that permit market participants to hedge the difference in prices between locations on the grid. SPP plans to implement an Energy Imbalance Service (EIS). It will redispatch generators that submit offers in the EIS Market to address imbalances between scheduled and actual transactions and, when the grid is congested, curtailments of generation participating in the EIS market. SPP is not planning to implement security-constrained unit commitment or FTRs during the first phase of its market development.

The Federal Energy Regulatory Commission (FERC) recently rejected SPP's proposed EIS tariff. The Commission's order calls the proposal "inadequate in several respects" and provides guidance on "key elements" that must be addressed "to help ensure successful implementation and monitoring of SPP's imbalance market."[1]

This report provides a quantitative and qualitative analysis of the impacts of Aquila-MO:

[1] *Southwest Power Pool,* 112 FERC ¶61,303 (September 19, 2005).

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- Joining and participating in the Midwest ISO;
- Participating in the proposed SPP EIS Market; or
- Operating its transmission facilities as a Stand Alone system outside these two adjacent RTOs.

The quantitative analysis is based on detailed production costing and power flow modeling of the three alternatives under a range of hurdle rate and fuel cost assumptions. The PROMOD IV® model used in this analysis provides a detailed representation of transmission and generation in the Eastern Interconnect including more than 40,000 transmission buses, 50,000 transmission lines, and 5,000 generating units. The quantitative analysis seeks to identify differences between alternative futures based on detailed analysis of a representative time period. Based on the availability of a detailed power flow and transmission system representation for the period, we have examined how the system would have performed in calendar year 2005 under each of the alternatives.

In analyzing the SPP EIS market, we assumed that ambiguities in SPP's proposed tariff and market rules and issues raised in the FERC's Order would be favorably resolved in a manner which optimizes the potential efficiency of the proposed EIS market design.

Our quantitative analysis looked at four economic indicators. We found that Aquila-MO participation in the Midwest ISO results in:

- The lowest production and purchased power costs for serving Aquila-Mo native load customers;
- The greatest benefit to Aquila-MO taking into consideration both production and purchased power costs as well as of off-system sales revenues;
- The lowest congestion costs for using the transmission system to serve Aquila-MO native load customers; and
- The lowest cost to serve Aquila-MO native load customers at wholesale market prices.

For each of the production cost and the congestion cost indicators, stand alone transmission operation represents the most costly or least beneficial option. Based on the cost to serve Aquila-MO customers at wholesale market prices, participation in the SPP market is the most expensive option.

Table I-1 presents the incremental annual costs of the SPP and Stand Alone options in excess of the costs associated Aquila-MO joining the Midwest ISO for these four economic indicators.

Table I-1 Summary of Base Case Results: Incremental Annual Cost of SPP and Stand Alone Operations in Excess of Operating Costs given Participation in the Midwest ISO

Perspective / Case	SPP	Stand Alone
Incremental Costs to Serve Native Load Customers	$5,697,448	$5,992,160
Incremental Utility Production and Purchased Power Costs Net of Off-system Sales Revenue	$3,309,011	$6,426,795
Incremental Congestion Costs to Serve Native Load Customers	$5,658,474	$6,045,702
Incremental Cost to Serve Native Load Customers at Wholesale Market Prices	$38,503,290	$26,787,849

These results reflect recurring annual costs. Over time, we would anticipate performance to be directionally consistent with our findings of lower costs for the Midwest ISO option. This conclusion is reinforced by our finding that Aquila-MO is able to purchase more on-peak energy at lower prices in the Midwest ISO and sells more energy, primarily off-peak, when modeled as being in SPP. Aquila-MO's off-system sales opportunities are likely to decline and its power purchases increase over time, as its own energy requirements increase in comparison to a fixed set of low cost resources.

There are three primary drivers in our quantitative analysis that distinguish the representation of transmission system operations within an RTO and outside of an RTO:

- In the absence of security-constrained economic dispatch, facilities in the transmission system that constrain system operations often end up being under utilized as a result of inefficient management of transmission congestion. Our analysis reflects the results of studies of average historical utilization of transmission during Transmission Loading Relief (TLR) events.
- We reflected appropriate transmission tariff rates in modeling opportunities for economic purchases and sales. These rates comprise the first of two components of what is known as a "hurdle rate."
- There are inherent inefficiencies – transaction and lost opportunity costs – in market participants' reliance on a bilateral purchases and sales that are not closely integrated with the operation of the transmission system. This has been conservatively reflected in a second hurdle rate component.

Our quantitative analysis of Midwest ISO and SPP transmission operations took into consideration two differences in how unit commitment and dispatch occurs within the two RTOs:

- The Midwest ISO provides regional security-constrained unit commitment services through a Day-Ahead Energy Market. SPP does not intend to provide regional unit commitment or to operate a Day-Ahead Energy Market.
- Unit commitment and dispatch within the Midwest ISO reflect the marginal cost of providing for transmission losses. The SPP EIS Market will not take into consideration marginal losses.

We have reflected these factors in our modeling. Our analysis assumes that in SPP all affected generators will offer into the EIS market although there could be instances in which generators have an incentive to not do so. To the extent that generators self-schedule and do not participate in the EIS market, this will tend to increase the cost to serve load in SPP.

We also discuss qualitative considerations regarding:

- The recent FERC decision on the proposed SPP EIS tariff;
- Specific elements in the structure of the proposed SPP EIS Market that may present potential economic and reliability risks when compared to a full LMP market such that that found in the Midwest ISO; and
- Longer-term benefits to participating in a fully transparent regional energy market.

These qualitative conclusions are directionally consistent with the results of our quantitative analysis. Our overall conclusion is that there are near-term and long-term economic benefits to Aquila-MO participating in an RTO. And, given the differences in services provided the Midwest ISO and SPP as well as the location of Aquila-MO load relative to key transmission constraints, membership in the Midwest ISO appears to offer greater economic benefits than participation in the SPP EIS market.

II. Introduction

The Missouri Public Service Commission (Missouri PSC) has requested information comparing the benefits and costs of Aquila's Missouri operating companies, Missouri Public Service Company and St. Joseph Power & Light Company, (hereafter jointly referred to as Aquila-MO) transferring operating control over their transmission facilities to one of two Regional Transmission Organizations (RTOs) or alternatively operating as a stand alone transmission system. Aquila-MO is could transfer transmission operations to either of two RTOs: the Midwest Independent Transmission System Operator (Midwest ISO) or the Southwest Power Pool (SPP). This study analyzes the economic impacts, risks, and opportunities for Aquila-MO participating in the Midwest ISO, participating in SPP, or operating its transmission on a stand alone basis outside of both the SPP and the Midwest ISO energy markets.

RTOs were created as a result Federal Energy Regulatory Commission (FERC) Order 2000 to: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate light handed regulation. FERC found that appropriate RTOs could successfully address impediments to efficient grid operation and lower electricity rates for consumers.[2]

The Midwest ISO and SPP RTOs differ in their geographic scope and services.

The Midwest ISO manages power flows and reliability for a much larger region. The Midwest ISO operates more than 97,000 circuit miles of transmission facilities for 28 member transmission owners in a region that covers 1.1 million square miles and includes most of Missouri, Iowa, and Illinois as well as portions of 12 other states and the province of Manitoba. The Midwest ISO includes most of the MAIN, MAPP, and ECAR reliability council regions. The Midwest ISO also provides independent tariff administration and transmission planning services to Duke Power, which operates 13,000 circuit miles of transmission in North and South Carolina. The operating costs of the Midwest ISO can be spread over a much larger volume of energy and generation. The Midwest ISO has a peak load of 119,000 MW and 131,000 MW of generating capacity. Coal-fired, nuclear, and hydroelectric units represent 77% of this generating capacity. Additionally, Duke Power has 15,000 MW of peak load and more than 24,000 MW of generation in the Eastern U.S.

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[2] *Regional Transmission Organizations,* 89 FERC ¶ 61,285 (December 20, 1999).

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SPP serves member companies in 7 states including portions of western Missouri, as well as Oklahoma and parts of Arkansas, Kansas, Louisiana, New Mexico, and Texas. Its members operate 52,000 circuit miles of transmission facilities in a region covering 255,000 square miles. In the SPP, the 2004 peak load was 38,767 MW, and the region includes nearly 55,000 MW of generating capacity, with 55% of that capacity being gas fired.[3]

The Midwest ISO provides regional reliability coordination. It has developed and operates one of the most sophisticated transmission network models in the industry. Its software permits the Midwest ISO in real-time to track power flows at metered locations, project flows at other locations across the grid, identify contingencies, and proactively avoid overloading transmission facilities. On April 1, 2005, the Midwest ISO implemented its Transmission and Energy Market Tariff (TEMT). Under this tariff, the Midwest ISO performs security-constrained unit commitment and economic dispatch at a regional level. Through regional unit commitment and dispatch, the Midwest ISO optimizes utilization of the transmission system and minimizes the economic impacts of transmission congestion for its members. Midwest ISO economic dispatch is based on resource offers and demand bids in a Real-Time Energy Market. Its unit commitment process reflects comparable offers and bids in a Day-Ahead Energy Market. Such offers and bids represent the prices at which market participants are willing to produce or purchase energy at specific times and locations. The Midwest ISO calculates prices and clears offers and bids, as frequently as every 5 minutes in the case of the Real-Time market, at 1,400 locations in the transmission system. Additionally, Midwest ISO energy markets are coordinated with those in the PJM region, creating a transparent market for power extending from the East Coast to Eastern Montana. The TEMT also creates opportunities for market participants to manage the risk associated with volatility in prices between specific generator and load locations through Financial Transmission Rights (FTRs). FTRs are a financial right for the holder of the FTR to receive payments equal to the difference in prices between a specified sink (typically a load zone) and a source (such as a specified generator). Following nominations made by market participants, FTRs are allocated to holders of transmission reservations to reflect the investment that utilities have made in their transmission systems and the transmission service that market participants have purchased. In addition to the Real-Time and Day-Ahead Energy Markets, the Midwest ISO also operates FTR markets that permit participants to adjust their FTR allocations.

SPP was organized as a regional reliability council in 1968, has provided regional tariff administration services since 1998, and was approved as an RTO in 2004. In compliance with

[3] Boston Pacific Company, *2004 State of the Market Report Southwest Power Pool Inc.* (May 31, 2005).

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FERC's approval of its RTO status, SPP has "the authority to direct the day-to-day operations of the Tariff Facilities in order to carry out its responsibilities as a Transmission Provider and Reliability Coordinator."[4] SPP coordinates information, estimates available transmission capacity, calls TLRs, and works with its 16 member control areas to ensure reliability. SPP has adopted a phased approach to implementing market based congestion management. In the first phase, SPP plans to implement a market based Energy Imbalance Service (EIS). Under SPP's proposed EIS tariff, customers either could arrange for energy imbalance service on their own or SPP would compensate participants for providing imbalance energy and pass the cost through to participants providing less (or using more) energy than was reflected in their transmission service schedules. SPP will provide its EIS through an offer-based EIS Market that will provide location-specific price signals. Generator participation in the EIS Market is voluntary in that resources may elect to self-schedule without submitting an offer or offer curve into the EIS Market. In September 2005, the FERC rejected SPP's proposed tariff for the EIS Market. SPP is expected to file a request for approval of a revised EIS tariff.

In phase one, congestion in the SPP transmission system will be managed through a combination of SPP's historical approach for managing congestion based on the North American Electric Reliability Council's (NERC's) Transmission Loading Relief (TLR) procedures and dispatch of generating units in the EIS market. When a TLR event is called to address congestion, there will be an allocation of responsibility to curtail transactions over the constrained facilities in the transmission system between market and non-market power flows. Market flows represent scheduled transactions from sources that have submitted offers to be redispatched in the SPP EIS market. Non-market flows include schedules from self-dispatched generation within the region and power flows related to imports, through-and-out transactions, and parallel or loop flows. Then, among the non-market flows, a further allocation of curtailment responsibilities occurs. Each of these allocations reflects priorities (based on type and duration of the underlying transmission service) in the NERC TLR procedures and SPP's market rules. These allocations represent a rationing of available transmission capacity that occurs without reference to price signals or the value of transmission to affected participants at the time of the TLR event. The curtailment responsibilities for market flows will be addressed through economic dispatch of units that have offered into the EIS market. EIS redispatch will take into consideration the transmission constraints for which a TLR event has been called.

SPP will not provide security-constrained unit commitment services or operate a Day-Ahead Energy Market. Market participants are expected to commit or contract for capacity to meet operating reserve requirements under their resource plans. Additionally, SPP will not offer

[4] *Southwest Power Pool, Inc.* 109 FERC ¶ 61,009 (October 1, 2004).

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Financial Transmission Rights in phase one. Parties will be able to limit their exposure to differences between generator (source) and load (sink) locational prices by reserving transmission capacity, scheduling transmission service, and following their transmission service schedules. However, market participants will not know in advance whether their schedules will be curtailed, potentially exposing them to congestion costs. In subsequent phases of market development, SPP will consider whether to create FTRs and markets for Operating Reserves, Regulation, and Frequency Response services. SPP has deferred implementation of subsequent phases of market development until after completion of a benefit – cost analysis.

If Aquila-MO were to operate its transmission as a stand alone system, it likely would not have the same capabilities as the RTOs to monitor regional power flows and identify contingencies that could impact system reliability. Additionally, as a stand alone transmission system, Aquila-MO would have to rely on the NERC TLR process to unschedule transactions across its system in order to relieve transmission constraints. Operating as a stand alone transmission system, Aquila-MO would not participate in regional security-constrained unit commitment or economic dispatch and could not determine in advance when it was economic to offer its generation into either the Midwest ISO or SPP energy markets. However, as a stand alone system it may avoid certain costs associated with RTO membership.

III. Approach

We have examined the economic impacts, risks, and opportunities for Aquila-MO participating in the Midwest ISO, participating in SPP, or operating its transmission on a stand alone basis outside of both the SPP and the Midwest ISO energy markets. The study includes both quantitative and qualitative analysis.

a. *Quantitative Analysis*

The quantitative analysis is based on detailed production cost and power flow modeling of the power system in the Eastern United States and Canada. This analysis was conducted using the PROMOD IV® model, which integrates hourly chronological production costing and detailed power flow analysis. Cases were analyzed in which Aquila-MO's transmission system was assumed to be managed "In the Midwest ISO", "In SPP", or on a "Stand Alone" basis outside of both the Midwest ISO and SPP energy markets. All cases were based on identical input assumptions related to loads, generator costs and characteristics, forecasted fuel[5] and emissions credit prices, and a base case power flow.

The model includes a representation of power system operations over most of the Eastern Interconnect. The Eastern Interconnect is the largest power grid in North America extending from Florida to Northern Texas and Eastern Montana to Ontario.[6] The model represents more than 5,000 generating units, 40,000 transmission buses, and 50,000 transmission lines. It was used to project production costs and location-specific, hourly market clearing prices. The model calculates and can track location-specific, hourly prices for up to 8,000 grid locations.

The focus of this analysis is on examining the impact of different approaches to managing transmission operations. Analyzing differences in transmission system operations requires a modeling approach that captures the integration of transmission operations with generation commitment and dispatch. The electric power system has unique characteristics that increase the complexity of system operations, reliability coordination, and congestion management:

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5 Oil and gas price forecasts reflect forward prices on the New York Mercantile Exchange adjusted for regional geographic basis differentials. Our analysis included high and low fuel price sensitivity cases in which all natural gas, oil, and coal prices were increased or decreased respectively by 20 percent.

6 The model included simplified representations of the Northeast Power Coordinating Council and Florida Reliability Coordinating Council regions, based on separate modeling of those regions.

- Power flows can change instantaneously. Following the laws of physics, when load, generation, or transmission facilities change, power flows immediately redistribute themselves along the paths of least impedance.
- The transmission system is operated on a contingency basis. That means operators must consider not only on the physical capabilities of each line, but how the flows over that line would change in the event of the failure of other transmission facilities.
- A single transaction from point A to point B produces a distribution of power flows that can affect transmission paths across a broad region. The changing overall pattern of generation, load, and transmission facilities in service determines which paths will be impacted. And in some circumstances, a power transfer in one part of the grid can produce a disproportionate impact on the ability to move power in a geographically distant portion of the system.
- Changing the dispatch of generation is the primary mechanism used to manage power flows. Thus, the reliability of the system and the efficiency with which congestion is managed are a direct function of the scope and efficiency with which generation is committed and dispatched to accommodate transmission constraints.

The operation of transmission cannot be studied in a simple model that treats the transmission system as a set of pipes with fixed capacities. It requires use of a chronological production costing and power flow model such as the PROMOD IV® model used in this study.

Our analysis began by integrating a NERC 2005 power flow case with a comparable SPP case. This power flow case helps determine how generation and load at specific locations will impact use of the grid. To accurately represent the topology of the transmission system, we identified and incorporated transmission upgrades and generation changes, then mapped generators and loads to specific busses in throughout the transmission system. Based on established Midwest ISO and SPP flowgates and an analysis of key constraints in the study area, we identified the operating security limits associated with 1,350 transmission facilities or "flowgates." Potential flows over facilities in this group are tracked for 534 different contingencies. Using hourly load and generation inputs, PROMOD models a security-constrained, chronological unit commitment and hour-by-hour dispatch of generation in each dispatch pool. In modeling the Midwest ISO TEMT, the Midwest ISO is treated as a single pool providing regional unit commitment and dispatch. The model represents 30 other pools, including SPP companies that must individually commit or contract for generation to meet resource and operating reserve requirements. The unit commitment and dispatch algorithm takes into consideration start-up costs, ramp rates, unit segment heat rates, constraints, the treatment of losses appropriate to each pool, and potential economic transactions.

The modeling was used to quantify differences between alternative futures based on modeling a representative time period. In this case, we selected calendar year 2005. We examined what would have been the impacts of implementation of the SPP EIS Market and the Midwest ISO TEMT for the full 12 month study period. Given the level of detail necessary to properly represent the relationship between transmission operations and the cost to serve load, the selection of a representative year for modeling is accepted to be a reasonable practice.

i. Key Factors in the Analysis

There are three primary factors that distinguish how the transmission system and energy markets within an RTO are represented from how areas outside of an RTO are represented.

- First, in the absence of security-constrained economic dispatch, the ability to make full utilization of the transmission system is reduced. For areas outside of the Midwest ISO, the SPP EIS Market, and other RTO markets, we represented the expected maximum utilization of flowgates during periods of transmission congestion based on studies of average historical utilization of flowgates during TLR events.
- Second, we reflected appropriate transmission tariff rates in modeling opportunities for economic purchases and sales in all cases. The selected transmission rates reflect the incremental transmission charges associated with purchasing energy from a different dispatch pool instead of generating power locally. Where a utility could purchase energy generated by another company under a Network Service tariff without paying incremental transmission charges, the transmission rate component was set to $0 per MWh. However, when Load Serving Entities (LSEs) purchase energy from a different transmission provider (RTO or individual control area), incremental transmission charges generally will apply. We have reflected these charges based on transmission rates for hourly non-firm point-to-point service. These rates comprise the first of two components of what is known as a "hurdle rate."
- Hurdle rates are also used in modeling to keep the model from over optimizing and representing a level of economic transactions that cannot be maintained using sequential bilateral purchases and sales. There are inherent inefficiencies in relying on bilateral transactions that are not closely integrated with the operation of the transmission system. These are reflected in a second hurdle rate component, which takes into account both transaction and lost opportunity costs. We specified hurdle rates that were conservative in that when we ran the model with these hurdle rates for a historical period (2004), the model produced a larger overall volume of economic purchases and sales for Aquila-MO than had actually occurred during that historical period.

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Our quantitative analysis of Midwest ISO and SPP transmission operations took into consideration two differences in how unit commitment and dispatch occurs within the Midwest ISO and will occur in the SPP EIS Market:

- The Midwest ISO provides regional security-constrained unit commitment services through a Day-Ahead Energy Market. SPP does not intend to provide regional unit commitment or to operate and Day-Ahead Energy Market. PROMOD IV® has separate unit commitment and dispatch calculations and permits the analyst to utilize different hurdle rates in each pass through the model. We have retained a unit commitment hurdle rate for SPP to reflect the lack of regional unit commitment in SPP.
- Unit commitment and dispatch within the Midwest ISO reflect the marginal cost of providing for transmission losses. In deciding whether to commit or dispatch each unit, the Midwest ISO takes into consideration whether an additional MW of energy from that unit will increase or decrease total transmission losses and the cost providing for those losses. The SPP EIS Market will not take into consideration marginal losses. We have utilized the capability of PROMOD IV® to select on a pool-by-pool basis whether marginal losses will be considered in unit commitment and dispatch.[7]

All else being equal, the Midwest ISO approach to these issues will tend to produce a more efficient commitment and dispatch of generation for the region as a whole.

Our analysis assumes that all generators whose operations could be impacted by SPP regional dispatch will offer energy into the EIS market at their marginal operating costs. And, we assumed that the EIS market thus will produce regional security-constrained economic dispatch within SPP. There may well be instances in which generators have an incentive to self-schedule or offer energy into the EIS market at a price that does not reflect its marginal costs. For example, a supplier with a network service transmission priority might find it to be economically advantageous to over schedule generators that utilize constrained transmission facilities so as to block its competitors' use of those facilities and capture additional downstream off-system sales. The EIS market prices only differences between scheduled and actual generation and would not penalize such behavior if the generators operate as scheduled. The individual supplier in this example might improve its profitability, while degrading the efficiency of economic dispatch and increasing the cost to serve load for the region as a whole. For purposes of our quantitative analysis, we have conservatively assumed that any such departures from security-constrained economic dispatch in the EIS market will not impact the cost to serve Aquila-MO load.

[7] For the cases in which Aquila-MO is in the Midwest ISO, a separate pool was created for Aquila unit power purchase contracts with generating units located outside of the Midwest ISO footprint.

ii. Congestion Management

When operating outside of a market based on regional security-constrained economic dispatch, the maximum amount of transmission capacity that can be effectively utilized is limited by the imprecision and inefficiency of historical approaches to congestion management. These approaches rely on physically rationing the transmission capacity that can be scheduled through calculations of Available Flowgate Capacity ("AFC") and physical curtailments of the actual utilization of transmission capacity under the NERC TLR procedures. This results in:

- Under utilization of transmission capacity even when the desire to utilize the transmission system exceeds its capabilities;
- Inefficient utilization of the available capacity without regard for the economic value of particular transactions in the hours when transmission has been over scheduled; and
- Reduced reliability.

Reliance on TLRs for congestion management inherently leaves transmission capacity under utilized because the TLR approach relies on imprecise flow estimates and does not accurately reflect system-wide interactions. The Reliability Coordinator who calls a TLR cannot accurately predict how much relief the constrained facilities will experience from each TLR curtailment.

Under NERC procedures, the impact of generators and control area-to-control area transactions on constrained facilities is estimated using power flow distribution factors. However, power flows estimated using NERC tools, such as the NERC Interchange Distribution Calculator (IDC), may not directly correspond to actual power flows, introducing an initial level of imprecision.

Moreover, TLRs are issued to curtail specific transmission schedules. When a schedule is curtailed, the affected control areas must then redispatch generation, curtail load, or reconfigure their systems to reduce the net interchange of power over the sum of their interconnections with other control areas. Each change in dispatch, load levels, or system configuration will have power flow impacts; and each of the parties to the curtailed transaction responds individually. The impact on the constrained flowgate of their individual responses to a curtailment can be difficult to accurately predict and track. Each of these actions takes time and occurs within constantly changing levels and patterns of load, generation and power flows. The parties may curtail their transactions and redispatch their respective generation in a manner that results in a lesser or greater than anticipated reduction in flows over the constrained transmission facility.

As a result, it is not possible for a Reliability Coordinator to use TLRs to maintain post-contingency power flows at a line's operating security limit on a sustained basis. Instead, greater curtailments than may eventually prove necessary must be called to avoid security limit violations. Consistent with the responsibility of Reliability Coordinators to avoid such violations, this means that some amount of transfer capability goes unused during TLR events.

We examined actual flows over congested flowgates during 927 Midwest ISO Level 3 of higher TLRs during 2003 (prior to implementation of regional economic dispatch in April 2005) and determined that after the curtailments occurred, under utilization of the transmission capacity of the congested flowgates during these TLR events averaged 12.7% of flowgate capacity. Under utilization of transmission capacity was somewhat higher in MAPP (15.6%) and WUMS (10.7%), than in the remainder of the Midwest ISO footprint (9.0%) during the TLR events studied. SPP conducted a similar analysis of flowgate under utilization during a sample of 22 TLR events and identified an average under utilization of constrained flowgates during these TLRs of 9.35%.

For areas that are outside RTO markets, we limited maximum flowgate utilization based on observed utilization. For those areas on which we did not have data on historical utilization, maximum utilization was limited to 91% of the facilities' operating security limits. The Midwest ISO's objective is to move as rapidly as feasible to 100% flowgate utilization using forward-looking 5-minute security-constrained economic dispatch under the TEMT. We also assumed that flowgates would be fully utilized within SPP following implementation of the SPP EIS market. This is an optimistic assumption given the lack of industry experience with the EIS approach being developed for SPP, its reliance on TLRs to identify internal constraints, and its use of the NERC IDC to allocate curtailment responsibility. This assumption may overstate the benefits of SPP participation relative to other options.

NERC TLR procedures allocate curtailment responsibilities without immediate regard for the economic value of the impacted transactions. When a curtailment is needed, all transactions in a selected service priority that impact the constrained flowgate by more than the minimum (5 percent) threshold are cut on a pro-rata basis. In the absence of a market, it is not possible to determine the economic impact of curtailing any particular transaction. However, it will often be the case that the costs of implementing a TLR greatly exceed the cost of a comparatively small redispatch that could provide the same reduction in flows over the constrained flowgate. SPP intends to continue relying on TLRs to curtail self-scheduled generation. The extent to which the SPP EIS Market improves economic outcomes compared to its historical reliance on TLRs will depend on the extent to which generators that are important to resolving transmission constraints do not self-schedule and submit offers in the EIS Market.

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Reliance on TLRs also impacts reliability.

- TLR procedures are cumbersome and time consuming. TLRs frequently take from 30 to 60 minutes to implement.
- The curtailed parties' responses and response times are uncertain, making it difficult for system operators to accurately predict whether actual flows will be brought back within security limits.

Our analysis of 2003 TLR events found that operating security limits were often exceeded during some portion of a TLR event.

iii. Hurdle Rates

PROMOD IV® commits and dispatches generation during separate passes through the model. This permits different hurdle rates to be applied during the unit commitment and dispatch process in the model. We have used this capability to reflect a difference between the Midwest ISO, that provides regional security constrained unit commitment and a Day-Ahead Energy Market, and SPP that leaves unit commitment decisions up to individual control areas and bilateral contracting between the companies.

In our analysis, hurdle rates reflect two factors. We began by identifying the actual transmission charges for key dispatch pools. Specific charges were identified for all source and sink pairs. Our transmission rate factor reflects the incremental transmission charges that would be associated with purchasing energy produced in another transmission area instead of generating power locally. Where a Load Serving Entity can purchase energy from another entity using Network Integration Service at no incremental cost relative to using its own generation, the transmission charge component was set to zero. Where positive transmission charges are included in the hurdle rate, hourly non-firm transmission rates were used.

The second component was designed to reflect transaction and lost opportunity costs associated with each potential purchaser and seller having to rely on multiple sequential bilateral transactions to continuously improve their positions and the dispatch of their resources in relationship to all other entities. The transaction and opportunity cost portion of the hurdle rate reflects the cumulative impact of several inherent inefficiencies in such bilateral contract markets, including:

- Each individual load serving utility tends to commit its own generation to ensure that it will be able to serve its native load.

- Markets that are not tightly integrated with the operation of the transmission system neither fully utilize transmission capacity nor identify all cost-effective transactions.
- Existing scheduling procedures limit market participants to whole hour or longer transactions. By contrast, the Midwest ISO energy markets will be able to optimize the operation of generation across member utilities at least every five minutes.
- Finding a cost-effective mix of purchases and sales requires bilateral negotiations with multiple other market participants. Such negotiations and the resulting transactions impose transaction costs related to the search for cost-effective transactions, negotiations, contracting, scheduling, settlement, managing counter-party risk, and dispute resolution. These transaction costs are a direct cost to bilateral market participants. They are either largely avoided (i.e., search, negotiations, contracting, and dispute resolution) or covered by the Midwest ISO charges (i.e., scheduling, settlement, and counter-party risk management) under the Midwest ISO's TEMT. To the extent it reduces self-scheduling and negotiated bilateral transactions, the SPP EIS Market has the potential to mitigate such costs with respect to dispatch, but not with respect to unit commitment and day-ahead transactions.
- In bilateral power market negotiations, each participant has an incentive to limit its disclosures to counter parties to maintain its advantages arising from the asymmetric availability of information and capture as large a portion of the benefits from the transactions as possible. Given imperfect information, identifying a cost-effective mix of transactions takes time and not all economic transactions will be discovered.
- Geographic price spreads occur in bilateral markets that do not reflect genuine differences in locational marginal costs. These spreads create misleading operating incentives that may fail to mitigate and in some cases exacerbate transmission congestion.
- Power markets are highly dynamic. Given the transaction costs and the time involved in completing bilateral transactions, the utilities' generation, purchases and sales are seldom fully optimized given continuously changing conditions.

For purposes of this analysis, we tested two sets of unit commitment and dispatch hurdle rates. Positive hurdle rates were applied during unit commitment to source – sink pairs that were not part of an integrated market or the same regional unit commitment process and, during dispatch, to pairs that were not part of an integrated market or the same regional economic dispatch process. In the base case, we utilized a flat $10 per MWh hurdle rate during the unit commitment pass through the model and a dispatch hurdle rate equal to $3 per MWh plus the applicable transmission tariff charge. We also conducted a sensitivity analysis in which a hurdle rate equal to $3 per MWh plus the applicable transmission tariff charge was applied during both unit commitment and dispatch.[8] The unit commitment and dispatch hurdle rates within and between the Midwest ISO and PJM were set to $0 per MWh to reflect the availability of Network Service, economic unit commitment and dispatch within these RTOs, the elimination of regional through-and-out rates (RTOR), and the joint operating agreement between these RTOs. Within SPP, the dispatch hurdle rate in each case was set to $0 to reflect the implementation of the EIS market. This reflects an optimistic assumption that suppliers will offer their potentially marginal units into the EIS Market. The unit commitment hurdle rate within SPP was set at $10 per MWh in the base case and $3 per MWh in the sensitivity case. These commitment hurdle rates within SPP reflect the availability of Network Service within SPP and alternative assumptions about the impact of transaction and opportunity costs, particularly the tendency of utilities to commit their own generation to ensure that they will control their ability to cover their own resource and reserve requirements.

The selected hurdle rates reflect a conservative estimate of the impact of barriers to optimizing unit commitment and dispatch in the absence of regional coordination and integration with transmission operations. They are equal to or lower than hurdle rates used in comparable studies. Table III-1 identifies a range of hurdle rates that have been used on other studies.

Table III-1: Comparison of Hurdle Rates Applied to Transactions Not Within an RTO

Study	**Unit Commitment Hurdle Rate**	**Dispatch Hurdle Rate**
U. S. Dept. of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (April 30, 2003)	Between Control Areas: $10/MWh	Between Control Areas: $5/MWh + Tariff Charge
CRA, *The Benefits and Costs of Dominion Virginia Power Joining PJM,* (June 25, 2003)	Between Control Areas: $10/MWh	$7/MWh for single control area to control area sale + $4/MWh for each additional control area to control area transfer
CRA, *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast* (November 6, 2002)	Between Control Areas: $10/MWh	$5/MWh + Tariff Charge
MISO – Aquila-MO Study Base Case	**Between Dispatch Pools: $10/MWh**	**Between Dispatch Pools: $3/MWh + Tariff Charge**
MISO – Aquila-MO Study Sensitivity Case	**Between Dispatch Pools: $3/MWh + Tariff Charge**	**Between Dispatch Pools: $3/MWh + Tariff Charge**

[8] A commitment hurdle rate of tariff charges plus $3 per MWh for almost every source – sink pair is lower than a flat hurdle rate of $10 per MWh.

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We initially tested these hurdle rates in benchmark cases based on 2004 data and pool configurations. In each case, the selected hurdle rates produced a larger overall volume of purchases and sales for Aquila-MO than actually occurred during 2004. Table III-2 compares the Aquila-MO transaction volumes from our benchmark runs with Aquila's 2004 Net Scheduled Interchange for its Missouri control area.

Table III-2: Comparison of 2004 Benchmark Case Aquila-MO Net Hourly Purchases and Net Hourly Sales to Actual 2004 Net Scheduled Interchange Volumes (MWH)

	Net Sch. Interchange		Base Hurdle Rate		Sensitivity Hurdle Rate	
	Purchases	Sales	Purchases	Sales	Purchases	Sales
January	-292,097	0	-339,205	0	-341,605	0
February	-263,427	0	-328,735	0	-331,302	0
March	-210,886	0	-276,217	0	-276,870	0
April	-245,673	0	-195,917	12	-206,433	0
May	-333,412	0	-305,840	0	-316,847	0
June	-250,942	342	-350,234	0	-363,014	0
July	-254,761	37	-376,517	0	-369,414	0
August	-311,647	64	-341,923	83	-350,085	1
September	-183,717	1,091	-331,865	0	-331,772	0
October	-222,806	0	-174,200	411	-185,781	185
November	-280,036	0	-225,311	0	-282,547	0
December	-344,934	0	-420,272	0	-406,641	0
2004	**-3,194,338**	**1,534**	**-3,666,235**	**506**	**-3,762,312**	**186**

The fact that purchases and overall transaction volumes in the benchmark cases exceed actual volumes is an indicator that the hurdle rates selected are conservative. Given the sensitivity of net purchase and sale volumes to model inputs, the relatively small difference between modeled and actual purchase and sale volumes suggests the model is providing a reasonable representation of Aquila-MO performance.

Finally, we modeled the cost to serve load under each of the three policy alternatives Aquila-MO in the Midwest ISO, in SPP, or operating on a stand alone basis using both the base case and sensitivity case hurdle rates. As we will see, the selection of hurdle rates had a very limited impact on the results.

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b. *Qualitative Analysis*

While the quantitative analysis provides indicators of the likely costs to consumers of pursing each of the three transmission operations alternatives, there are other factors that are less easily quantified. To address these issues, we have included qualitative assessments of issues related to:

- The recent FERC decision rejecting the proposed SPP EIS tariff;
- The structure of the proposed SPP EIS Market;
- The reliability impacts of the SPP EIS proposal; and
- Longer term benefits of participating in a transparent regional energy market.

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IV. Quantitative Results

a. *Scenario Analysis*

We conducted a series of PROMOD IV® model runs to analyze the relative benefits and costs of each of three policy alternatives: Aquila-MO joins the Midwest ISO and offers its generation into the Midwest-ISO Day-Ahead and Real-Time Energy Markets, Aquila-MO joins SPP and participates in the SPP EIS market by submitting offer curves for all its potentially marginal units, and Aquila-MO operates on a stand alone basis outside of the markets implemented by both the Midwest ISO and SPP.

Each of the three cases was fully analyzed in four primary scenarios:

- *Base Case:* For the base case, we projected natural gas, distillate oil, and residual oil prices based on applying historical basis differentials (reflecting the delivered cost of spot fuels) to 2005 gas, distillate oil, and crude oil prices in the NYMEX futures market. Coal and nuclear fuel forecasts were based on plant specific forecasts for 2005 provided by Platts. For source to sink pairs where it was appropriate to apply a positive hurdle rate, the Base Case used a $10 per MWh unit commitment hurdle rate and a dispatch hurdle rate equal to the applicable incremental tariff charges plus a $3 per MWh component to take into consideration transaction and lost opportunity costs. The unit commitment and dispatch hurdle rates within RTOs such as the Midwest ISO that perform both regional unit commitment and dispatch were set to $0 per MWh. For transactions within the SPP RTO, the dispatch hurdle rate was set to $0 per MWh assuming efficient operation of the SPP EIS Market and a $10 per MWh hurdle rate was applied during unit commitment.
- *Hurdle Rate Sensitivity:* In these cases, positive unit commitment and dispatch hurdle rates were set at the applicable incremental tariff charges plus a $3 per MWh component to take into consideration transaction and lost opportunity costs. For virtually all source to sink pairs, this represented a reduction in the commitment hurdle rate. This sensitivity case was designed to evaluate the impact of reducing the unit commitment hurdle rate within SPP from $10 per MWh to $3 per MWh.
- *Low Fuel Cost Sensitivity:* This scenario modifies the Base Case scenario by reducing gas, oil, and coal prices by 20%.
- *High Fuel Cost Sensitivity:* This scenario modifies the Base Case scenario by increasing gas, oil, and coal prices by 20%.

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We also conducted an additional model runs to identify what would be the impact of eliminating regional through-and-out rates between SPP and the Midwest ISO.

In each case, we have assumed that markets are effectively competitive.[9] For purposes of these cases, we also have assumed that all potentially marginal generation is offered into the SPP EIS Market. For reasons discussed in our qualitative analysis, this is a potentially optimistic assumption and may over state the benefits of Aquila-MO participation in SPP relative to other options.

Given available data, it would be difficult at this time to develop a complete picture of all costs and revenues associated with each of the three options. For example, it would be difficult to determine in advance how Aquila-MO would reserve and schedule transmission capacity in SPP and which of those schedules in what hours might be curtailed exposing the company to imbalance charges in the EIS Market. Quantification of potential transmission revenue distributions also would require making a number of assumptions. And, it would be misleading to compare currently projected SPP administrative charges to those for the Midwest ISO. Currently projected SPP administrative charges are on average lower than those in the Midwest ISO.[10] However, it is unlikely that SPP will be able to sustain a significant administrative cost advantage and provide services similar to the congestion management services offered by the Midwest ISO. SPP has yet to implement its imbalance market. And, it has not completely defined the on-going responsibilities of the RTO and its member control areas, making it more difficult to accurately assess total participant costs. The Midwest ISO has completed a large investment in regional reliability coordination, implemented its energy and FTR markets, and is settling more than a billion dollars of transactions per month. Although we requested additional information, we have not had access to sufficient data to conduct a detailed review of SPP's projections of RTO and EIS costs. The most plausible outcome is that the administrative costs to Aquila-MO for participating in the SPP EIS market or Midwest ISO RTO will be similar. Although the Midwest ISO incurs costs to provide additional services, those costs are recovered from a much larger customer base. To the extent SPP provides fewer services, additional costs may be borne by SPP control areas and market participants.

[9] Alternatively, it may be assumed that the Midwest ISO and SPP Independent Market Monitors have been effective in reducing and mitigating any attempts to exercise market power.
[10] Prior to its review of the recent FERC Order, the SPP Finance Committee forecasted that 2006 SPP expenditures will run at $0.18 / MWh. SPP Finance Committee Meeting Minutes (September 19, 2005). The Midwest ISO projects that 2006 Midwest ISO costs will average $0.385 / MWh. For Aquila-MO, this represents a difference of approximately $1.7 million in 2006. Even if the differential in administrative charges were to remain at this level, it would not change the direction of our findings.

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Our analysis focuses on the larger economic impacts of Aquila-MO participation in alternate approaches to transmission operations. Answering basic economic questions about power production costs, transmission costs, and wholesale prices will provide regulators insight regarding which of the three options offers the largest potential benefits and potentially the greatest flexibility for allocating rights, revenues, and costs.

We analyzed the results of our modeling scenarios from four perspectives:

- Which option results in the lowest production costs for serving Aquila-MO native load customers?
- Which option produces the greatest benefit to Aquila-MO taking into consideration both production cost savings and potential margins from off-system sales?
- Which option results in the lowest congestion costs for using the transmission system to serve Aquila-MO native load customers?
- Which option produces the lowest wholesale market prices and would result in the lowest costs for serving Aquila-MO native load at wholesale market prices?

b. Summary of Quantitative Results

Among the three options, Aquila-MO participation in the Midwest ISO results in:

- The lowest production and purchased power costs for serving Aquila-MO native load customers;
- The greatest benefit to Aquila-MO taking into consideration production and purchased power costs net of off-system sales revenues, despite somewhat higher off-system sales when Aquila-MO is in SPP;
- Given the location of Aquila's load and transmission constraints, the lowest congestion costs to serve Aquila-MO native load customers;
- The lowest cost to serve Aquila-MO native load customers at wholesale market prices.

For each of the production cost and the congestion cost indicators, the Stand Alone option represents the most costly or least beneficial option. Based on the cost to serve Aquila-MO customers at wholesale market prices, participation in the SPP market would represent the most expensive option.

From our Base Case Scenario, Table IV-1 presents the incremental annual costs of the SPP and Stand Alone options in excess of the costs associated Aquila-MO joining the Midwest ISO.

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Table IV-1 Summary of Base Case Results: Incremental Annual Cost of SPP and Stand Alone Operations in Excess of Operating Costs given Participation in the Midwest ISO

Perspective / Case	SPP	Stand Alone
Incremental Costs to Serve Native Load Customers	$5,697,448	$5,992,160
Incremental Utility Production and Purchased Power Costs Net of Off-system Sales Revenue	$3,309,011	$6,426,795
Incremental Congestion Costs to Serve Native Load Customers	$5,658,474	$6,045,702
Incremental Cost to Serve Native Load Customers at Wholesale Market Prices[11]	$38,503,290	$26,787,849

Using the Base Case Scenario, Table IV-2 presents the total annual costs of the Midwest ISO, SPP, and Stand Alone options.

Table IV-2 Summary of Base Case Results: Annual Cost of MISO, SPP, and Stand Alone Transmission Operations

Perspective / Case	MISO	SPP	Stand Alone
Costs to Serve Native Load Customers	$151,071,754	$156,769,202	$157,063,914
Utility Production and Purchased Power Costs Net of Off-system Sales Revenue	$148,053,013	$151,362,024	$154,479,808
Congestion Costs to Serve Native Load Customers	-$3,189,265	$2,469,209	$2,856,438
Cost to Serve Native Load Customers at Wholesale Market Prices	$214,936,733	$253,440,017	$241,724,576

Taken together the production and congestion cost measures provide a "bottoms-up" indicator of the economic costs of each option to the region. Depending on whether one adopts a consumer or utility perspective and on the regulatory treatment of margins on off-system sales, the Cost to Serve Native Load Customers and the Utility Production and Purchased Power Costs Net of Off-

[11] These values are calculated based on projected Midwest ISO LMPs for the Aquila-MO load zone. Midwest ISO prices are lower than those in the SPP and Stand Alone cases in part because the Midwest ISO takes the value of marginal losses into consideration in calculating prices. If we hypothetically calculated Midwest ISO prices in the manner proposed for the SPP EIS market without taking loss impacts into consideration (while continuing to reflect the Midwest ISO's use of marginal losses in unit commitment and dispatch), the incremental cost to serve load at wholesale market prices would be $16,437,157 for participation in the SPP EIS Market and $4,721,716 under Stand Alone operations.

system Sales Revenues bound the generation and power purchase (and sales) costs (and revenues) associated with these options. We have calculated the internal congestion costs between Aquila-MO's generation and its load. The difference between congestion costs in the different cases is an indicator of the economic costs associated with use of the transmission system to serve native load customers.

The cost to serve native load at wholesale market prices provides an additional perspective on the economic impacts of each of the options. This indicator is provided because:

- Aquila-MO purchases a majority of the energy used to serve its load. Most of those purchases today occur under unit contracts at comparatively low prices. These contracts serve approximately 45% of the company's load. The cost to serve load at wholesale market prices provides one indicator of the relative costs that the Company might face if it had to replace these contracts.
- The cost to serve load at wholesale market prices is an indicator of the relative cost to serve additional load resulting from either natural load growth or economic development.
- Wholesale market prices could have a direct impact on consumers in the event that Missouri should decide to permit retail access to the wholesale market.
- It is a measure of underlying economic value, reflecting how much consumers would have to pay in a competitive market to receive the same electricity service.

Based on our analysis, participation in the Midwest ISO is the option with the lowest economic costs. The primary factors that appear to contribute to this result are:

- With access to a larger market and lower cost resources, Aquila-MO is able to make greater power purchases (outside of its pre-existing unit contracts) at lower prices largely during peak periods when it is in the Midwest ISO. This is reflected in lower total and average production and purchased power costs.
- Integration of Aquila-MO with the specific resources and loads in the Midwest ISO and a more efficient Midwest ISO dispatch protocol also contribute to the lower total and average production and purchased power costs when Aquila-MO is in the Midwest ISO.
- Aquila-MO is located near the upstream end of regional power flows in the Midwest ISO. Additional generation in this portion of the grid, all else being equal, increases transmission losses. When marginal transmission losses are considered in pricing, it reduces the value and price of energy in Aquila-MO's portion of the grid. The fact that Midwest ISO markets reflect the value of marginal losses in energy prices will reduce the price of additional power purchases for Aquila-MO when it is in the Midwest ISO.
- Aquila-MO congestion costs are lower, and projected to be negative for the year, when the Companies are in the Midwest ISO. The locational marginal prices (LMPs) used in

the calculation of congestion costs are on average higher at Aquila-MO generators than at Aquila-MO load buses in the Midwest ISO. Aquila-MO loads are located immediately upstream from transmission constraints. When the Companies are in the Midwest ISO, the seam between the Midwest ISO and areas to the west and north concentrates the effect of the constraints in reducing upstream prices on Aquila-MO load prices and to some extent changes the pattern of constraints observed.

- Wholesale energy prices in Aquila-MO are lower in the Midwest ISO case, than in SPP or Stand Alone cases. Prices in the Stand Alone case also are lower than in with Aquila-MO in SPP. This is due to the location of Aquila-MO loads upstream from an transmission constraints which tend to depress prices for Aquila-MO; the greater prevalence of gas-fired capacity and often higher prices in SPP; tariff charges and inefficiencies in bilateral markets[12] that prevent Aquila-MO prices in both the Midwest ISO and Stand Alone cases from rising to SPP levels; improved access to low cost generation when Aquila-MO is in the Midwest ISO; and the treatment of marginal losses in Midwest ISO energy prices. This is reflected in lower prices, lower purchased power costs, and a lower cost to serve load at wholesale market prices under the Midwest ISO option.

We evaluated the same indicators in each of the other three scenarios – low hurdle rates, high fuel costs, and low fuel costs – and found the differences between the options to closely match those in the base case scenario. This suggests a consistent relationship in the relative costs of the three options across a range of potential futures.

c. *Production Costs: A Utility Perspective*

We simulated generation – including fuel, operating and maintenance, SO_2 allowance, and NO_x SIP call emissions credit – costs, power purchase costs for both existing unit contracts and short-term purchases, and power sales revenues to analyze the costs of each RTO option.

Participation in the Midwest ISO is the least costly option. It produces both lower total costs, see: Table IV-9 in the Comparison Tables below, and lower average production and purchased power costs for meeting load and supporting off-system sales. The average production and purchased power cost when Aquila-MO was modeled as in the Midwest ISO was $18.61 per MWh of load and off-system sales. This compares to an average cost of $19.13 per MWh when Aquila-MO was modeled as being in SPP and $19.43 when the Company operates its transmission system

[12] See the discussion of Hurdle Rates beginning at p. 16.

on a stand alone basis. Lower costs reflect lower purchased power costs and a more economic integration of load and resources and when Aquila-MO is in the Midwest ISO.

When we compare the option of participation in the Midwest ISO to membership in SPP, we find that power production and purchase costs are lower in the Midwest ISO and power sales revenues and margins are higher when Aquila-MO is in SPP. However, the improvement in off-system sales margins in SPP is not enough to offset the lower costs associated with the Midwest ISO option. Table IV – 3 provides details related to power purchases and sales for the three base case modeling runs. It shows that Aquila-MO is able to purchase nearly 110,000 MWh more on-peak power outside its existing unit contracts when in the Midwest ISO than when it is in SPP. And, it could do so at lower prices. Non-unit contract purchased power prices have been set at the average load zone LMP for the hour in which the purchase occurs.[13] These additional purchases provide lower cost energy to Aquila-MO during peak periods when its costs are highest.[14] When Aquila-MO is modeled as being in SPP, it makes more off-system sales and its average off-system sales price is higher than when it is in the Midwest ISO. However, most of the off-system sales that Aquila-MO can make occur in off-peak hours when prices are low. In the off-peak hours, transmission congestion is limited and Aquila-MO can sell excess coal fired generation in SPP. Aquila-MO does not have sufficient low cost generation to be a net seller during on-peak periods.

Participation in the Midwest ISO also results in lower average generation costs. The Companies' average variable power production costs are $14.6 per MWh when Aquila-MO is in the Midwest ISO, $15.0 per MWh in SPP, and $15.2 per MWh on a Stand Alone basis. Integration with the Midwest ISO allows Aquila-MO to reduce reliance on its highest cost generators by more than 50% compared to the SPP and Stand Alone cases.

It should be remembered that the costs that we have modeled for 2005 are recurring annual costs. Over time, we would anticipate performance to be directionally consistent with our findings of lower costs for the Midwest ISO option. This conclusion is reinforced by the likelihood that

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[13] In the cases when Aquila-Mo is in the Midwest ISO, purchased power costs have been adjusted to reflect the refund to Aquila-MO of the over collection of loss related revenues associated with the Midwest ISO's treatment of marginal losses.

[14] The increase in purchases represents a change in total power purchases from all sources. For the Midwest ISO scenario, the maximum amount of Aquila-MO purchases from all sources in any hour is 902 MW. The primary transmission line connecting the Midwest ISO to Aquila-MO (Overton to Sibley) did not reach its maximum capacity in the study. The Missouri Coordination Agreement of April 22' 1968 provides a mechanism for Aquila-MO to reserve unused capacity on the line in excess of it initial allocation; the agreement states that other parties cannot unreasonably withhold their consent to such uses of the line; see: Article IV, Section 4.

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Aquila-MO's off-system sales opportunities will decline and its power purchases increase, as its own energy requirements increase in comparison to a fixed portfolio of low cost resources.

When we compare participation in the Midwest ISO or SPP to operation of Aquila-MO's transmission system on a stand alone basis, operating outside either RTO results in the highest economic costs. The Stand Alone case results in higher production and purchased power costs and lower off-system sales revenues than the case in which Aquila-Mo is in the Midwest ISO (See: Table IV – 8, below). And, the volume of off-system sales which Aquila-MO could make as a stand alone system is much lower, 496,632 MWh, than would be anticipated in the Midwest ISO, 661,280 MWh, or in SPP, 883,063 MWh. These much lower off-system sales volumes

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Table IV - 3
Base Case Purchases and Off-System Sales Comparison - August 15, 2005

	Aquila-MO in MISO	Aquila-MO in SPP	Aquila-MO Stand Alone
Power Purchases (MWh)	4,586,194	4,545,408	4,360,643
Power Purchases as Percent of Load (%)	57.8%	57.3%	55.0%
Unit Purchases (MWh)	3,593,224	3,686,988	3,481,391
Unit Purchases as Percent of Load (%)	45.3%	46.5%	43.9%
Non-Unit Purchases (MWh)	992,970	858,420	879,252
On-Peak Non-Unit Purchases (1) (MWh)	884,868	774,893	791,409
Average Purchased Power Price ($/MWh)	$17.06	$17.94	$18.13
Average Price of Non-Unit Purchases ($/MWh)	$37.68	$46.36	$45.35
Average Load Zone LMP ($/MWh)	$27.09	$31.95	$30.47
Purchased Power Costs ($)	$78,241,574	$81,538,833	$79,050,055
Cost of Non-Unit Purchases ($)	$37,411,528	$39,796,554	$39,875,706
Off-System Sales (MWh)	661,280	883,063	496,632
Off-System Sales in Off-Peak Hours (2) (MWh)	526,397	669,454	345,980
Average Off-System Sale Price ($/MWh)	$17.95	$19.60	$18.79
Average Cost of Off-System Sales ($/MWh)	$13.39	$13.48	$13.59
Average Generation LMP ($/MWh)	$26.47	$29.17	$28.00
Off-System Sales Revenues	$11,870,313	$17,307,522	$9,332,903
Cost of Off-System Sales ($)	$8,851,572	$11,900,344	$6,748,797
Off-System Sales Margin ($)	$3,018,741	$5,407,178	$2,584,106

(1) Weekdays between 7:00 am and 11:00 pm.
(2) Weekends & Weekdays between 11:00 pm and 7:00 am.

drive costs net of off-system sales revenues in the Stand Alone case above those projected for Aquila-MO participation in SPP. It is not be surprising to see lower off-system sales volumes when Aquila-MO's transmission system is modeled on a Stand Alone basis. Purchasers in the SPP or in the Midwest ISO would face additional transmission charges; Aquila-MO would face a more difficult challenge optimizing its dispatch, purchases and sales; and it would face competition from two large adjacent regional markets.

The finding of lower costs associated with participation in the Midwest ISO is consistent across a range of cases. Table IV – 4 summaries base and sensitive scenario results for the three options, presenting the sum of total generation and purchased power costs, less off-system sales revenues.

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Table IV - 4
Utility Perspective: Production & Purchased Power Costs Net of Off-System Revenues: Summary of Cases - August 15, 2005

Case / Sensitivity	Net Annual Recurring Production Costs for Aquila Missouri			
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In MISO	$148,053,013	$148,274,301	$141,154,028	$154,501,902
In SPP	$151,362,024	$151,506,796	$144,959,560	$157,827,818
Stand Alone	$154,479,808	$154,599,189	$147,741,139	$160,987,342

	Costs in Excess of MISO Membership			
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In SPP	$3,309,011	$3,232,494	$3,805,532	$3,325,916
Stand Alone	$6,426,795	$6,324,888	$6,587,111	$6,485,440

d. *Production Costs: Cost to Serve Native Load*

The extent to which consumers may or may not benefit from increased margins on off-system sales is a regulatory issue that is outside the scope of our analysis. We have processed the results of our modeling to identify the cost to serve native load independently of off-system sales margins. To do so, we identified the lowest cost resources sufficient to meet native load requirements on an hour-by-hour basis. All remaining production and purchased power costs in hours when Aquila-MO was a net seller were assumed to have been incurred to support off-system sales. After deducting costs incurred to support off-system sales, we are able to compare the production and purchased power costs associated with serving native load customers alone.

When we consider only the costs required to serve native load and exclude margins earned on off-system sales, the cost of the SPP option increases relative to the remaining options. From this consumer perspective, the costs of participating in the SPP EIS market are nearly as high as the costs of Stand Alone operations. These results are consistent across the scenarios that we analyzed. In terms of costs incurred to serve native load, the SPP option would be $5.7 million to $6.0 million per year and the Stand Alone option would be $6.0 million to $6.2 million more expensive than participating in the Midwest ISO. Table IV – 5 summarizes the results of our base case scenario and our sensitivity cases from the perspective of costs incurred to serve native load.

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Table IV - 5

Consumer Perspective - Cost to Serve Aquila-MO Native Load: Summary of Cases - August 15, 2005

Case / Sensitivity	Net Annual Recurring Cost to Serve Aquila-MO Native Load			
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In MISO	$151,071,754	$151,243,533	$144,174,541	$157,686,468
In SPP	$156,769,202	$156,987,144	$150,193,854	$163,516,067
Stand Alone	$157,063,914	$157,412,900	$150,209,743	$163,851,904
	Costs in Excess of MISO Participation			
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In SPP	$5,697,448	$5,743,610	$6,019,313	$5,829,599
Stand Alone	$5,992,160	$6,169,367	$6,035,202	$6,165,436

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e. *Congestion Costs*

The congestion costs to serve Aquila-MO native load are lower when the company is in the Midwest ISO than under the remaining options. This is an indication that participation in the Midwest ISO reduces the economic costs of using the transmission system to serve Aquila-MO load when compared to Aquila-MO participation in SPP or Stand Alone operations.

Congestion costs represent a portion of the difference in market clearing prices between load and generator locations in a given hour. These differences are impacted by the location of load and generation relative to the then binding transmission constraints. While simple illustrations often portray power moving from a low cost generator, potentially across a constrained interface, to load that, as a result of the constraint, sees higher prices, there also will be cases in which prices at utility's load may be lower than the prices at its generators. In such cases, increasing consumption at the utility's load buses might contribute to reducing congestion and create counter flows (in the opposite direction of the primary flow) across a nearby constraint.

In the transmission grid, prices at each location will be impacted by the direction of power flows, the location of marginal (price setting) resources, the electrical proximity of the location to binding constraints, and other factors such as tariff charges or transaction and opportunity costs that prevent prices from equalizing between adjacent entities. All else being equal, prices tend to be highest immediately downstream from a binding transmission constraint and fall as one moves further downstream from the constraint and other factors come into play. Similarly, all else being equal, prices tend to be lowest immediately upstream from a binding constraint and increase as one moves further upstream from the constraint. While the price pattern may break between companies or pools where transmission charges and trading costs come into play, in a complex system with multiple constraints and units impacting prices, the price impact of each constraint becomes increasingly diluted at buses further downstream or upstream from the transmission line that is operating at full capacity.

Our analysis identified regional congestion patterns in SPP that were very similar to and constrained flowgates that were identical to or in series with those identified by the SPP market monitor.[15] And, within the Midwest ISO footprint, we also identified transmission constraints in our modeling that are commonly observed in operations. Figures IV – 1 through IV – 4 illustrate

[15] Boston Pacific Company, Inc., *2004 State of the Market Report Southwest Power Pool Inc.* (May 31, 2005).

of some of the congestion patterns found in our analysis. Each of these particular illustrations was taken from the base case with Aquila-MO in the Midwest ISO.

The pattern shown in Figure IV – 1 is among the most commonly observed. Located in northwestern Missouri, Aquila-MO is often upstream from the key transmission constraints. The Midway to St. Joseph constraint that appears upstream from Aquila-MO in Figure IV – 4, occurred in less than 125 hours in the Midwest ISO and SPP cases. Transmission facilities located between Aquila-MO generators and loads are not constraining in most hours. Thus, overall congestion costs internal to Aquila-MO were low compared to more constrained portions of the grid.

Congestion costs were calculated in all cases based on the difference in marginal energy costs at Aquila-MO load buses less marginal energy costs at Aquila-MO generation buses after excluding the loss related component of LMPs from both sets of prices. The difference between load zone LMPs without losses and generator LMPs without losses was then multiplied by hourly loads less short term power purchases to compute congestion costs internal to Aquila-MO. Power purchases not from existing unit contracts were excluded from the calculation because these purchases are valued at load zone prices in our analysis, and thus already include a congestion component.

When Aquila-MO was in SPP or operated on a Stand Alone basis, congestion costs were positive and \$2.5 million and \$2.9 million per year respectively in the Base Case. However, when Aquila-MO is in the Midwest ISO, congestion costs are a negative \$3.1 million per year or \$5.6 million and \$6.0 million below the levels in the SPP and Stand Alone cases respectively. Reviewing a selection of hours in which negative congestion costs occurred in the Midwest ISO case, we observed a pattern in which Aquila-MO loads play a greater role in managing the Stockton to Morgan transmission constraint when Aquila-MO is in the Midwest ISO. Aquila-MO is upstream from Stockton – Morgan and its loads tend to be closer to that constraint than its generating facilities. When Aquila-MO is in the Midwest ISO, prices at its load buses immediately upstream from the Stockton – Morgan constraint are depressed relative to some of its generator prices. By contrast, when we review the same hours in the SPP case, the change in prices that occurs as one moves further upstream from Stockton – Morgan and other constraints occurs more gradually. Figures IV – 5 and IV – 6 illustrate these effects. Figure IV – 7 compares the relationships between the hourly price spread across the Stockton – Morgan constraint and

Aquila-MO hourly congestion costs for the Midwest ISO and SPP cases.[16] Considered over the year, there is a greater variation in congestion costs and more negative congestion costs when Aquila-MO is in the Midwest ISO. Congestion costs are lower (more negative) when Aquila-MO is in the Midwest ISO because the LMPs excluding losses at its load hub are lower in the Midwest ISO case than in the other cases relative to the LMPs without losses at Aquila-MO's generation and in particular at the generators in SPP and MAPP control areas from which it makes unit contract purchases.[17] While prices in the Aquila-MO control area immediately upstream of the Stockton – Morgan constraint fell more sharply in the Midwest ISO case than in the other cases, LMPs at the unit contract generator locations were consistent across the cases. The average Aquila-MO load hub LMP without losses is $29.88 / MWh in the Midwest ISO case, $30.47 under Stand Alone operations, and $31.95 with Aquila-MO in SPP. .Aquila-MO load benefits in the Midwest ISO from reduced prices and is rewarded with negative congestion costs because Aquila-MO load tends to create counter flows to alleviate the Stockton – Morgan (and in some hours additional) constraint(s).

The differential in congestion costs between cases is consistent across all of the scenarios that we analyzed. Table IV – 6 summarizes congestion costs in the Base Case, Low Hurdle Rate, Low Fuel Cost, and High Fuel Cost scenarios.

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[16] When the Stockton – Morgan constraint is binding, the dominant flow is typically from north (Stockton) to south (Morgan). In such instances, the LMP at Stockton will be less than the Morgan LMP and the spread between Stockton and Morgan LMPs will be negative.

[17] These generators include Cooper, Gentleman, Iatan, and Jeffrey generating units. With the exception of minor variations in the operation of the Gentleman units that are located in western Nebraska, these units operate similarly in each of the scenarios analyzed. LMPs without losses at these units also tend to be very comparable in the different scenarios. The average LMP without losses at these units is $0.13 higher in the Midwest ISO case than when Aquila-MO is in SPP.

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Figure IV - 1

In MISO Constraints & Price Profiles January 15 Hour 9

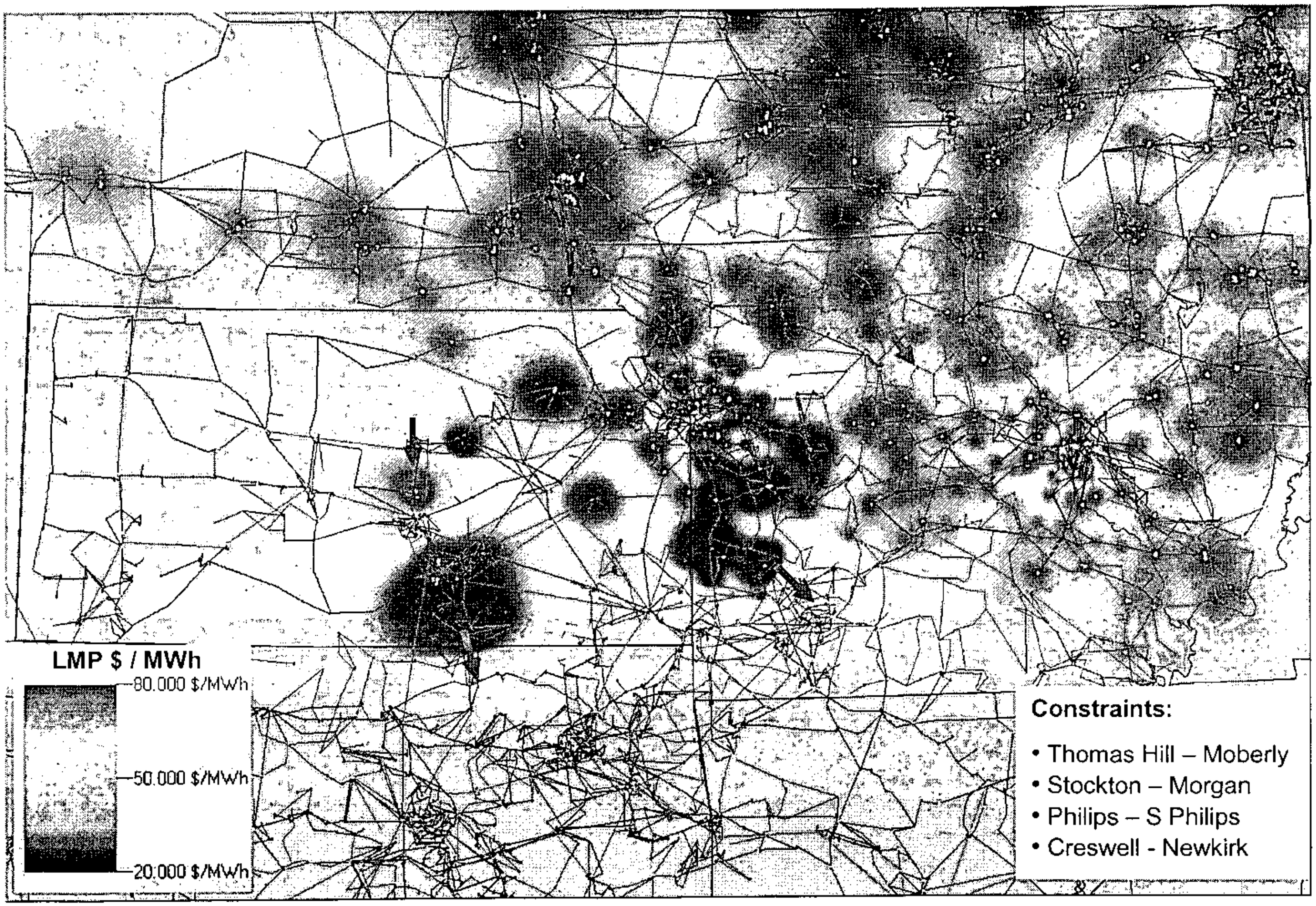

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Figure IV - 2

In MISO Constraints & Price Profiles April 19 Hour 14

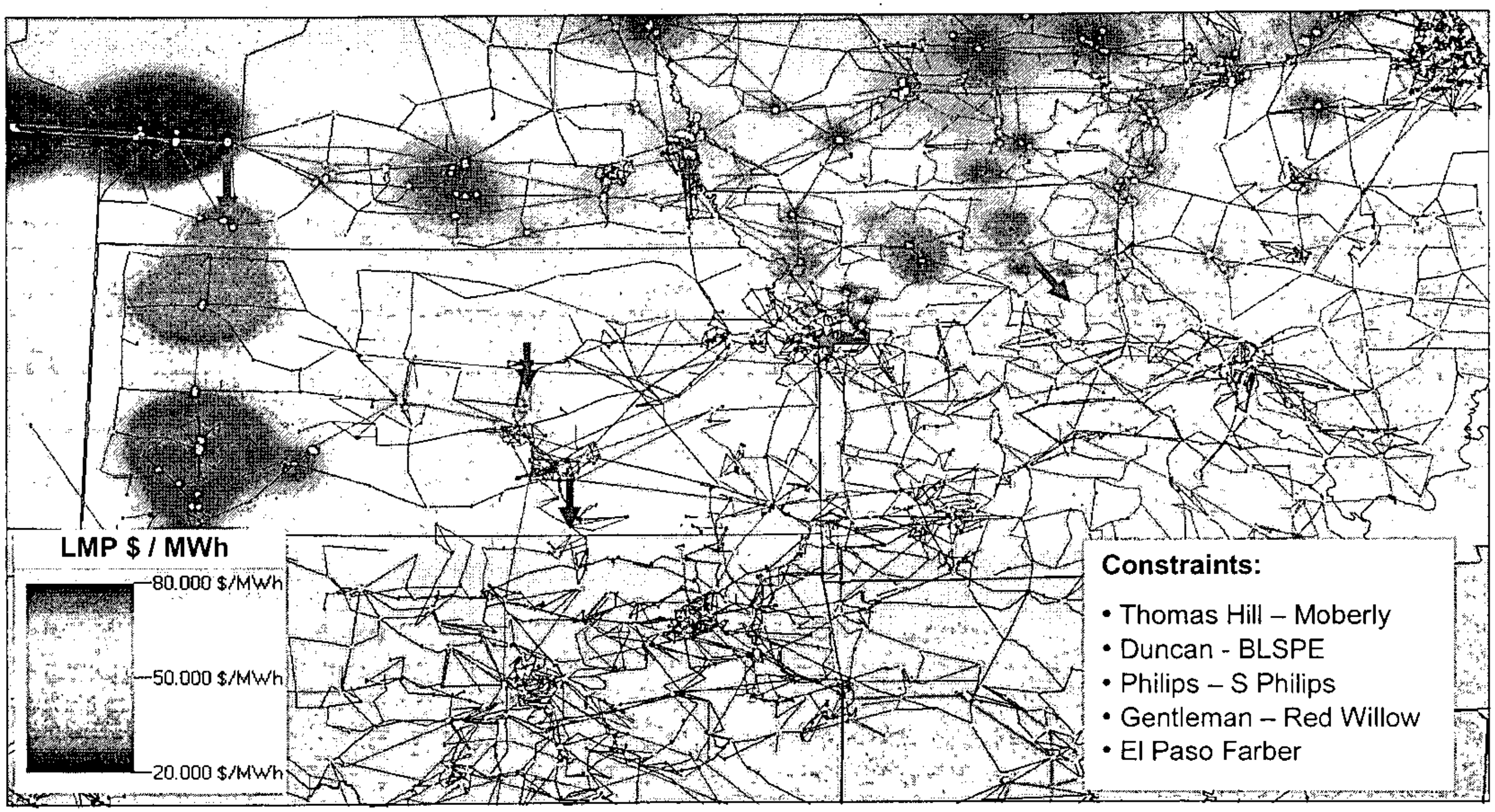

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Figure IV - 3

In MISO Constraints & Price Profiles July 14 Hour 18

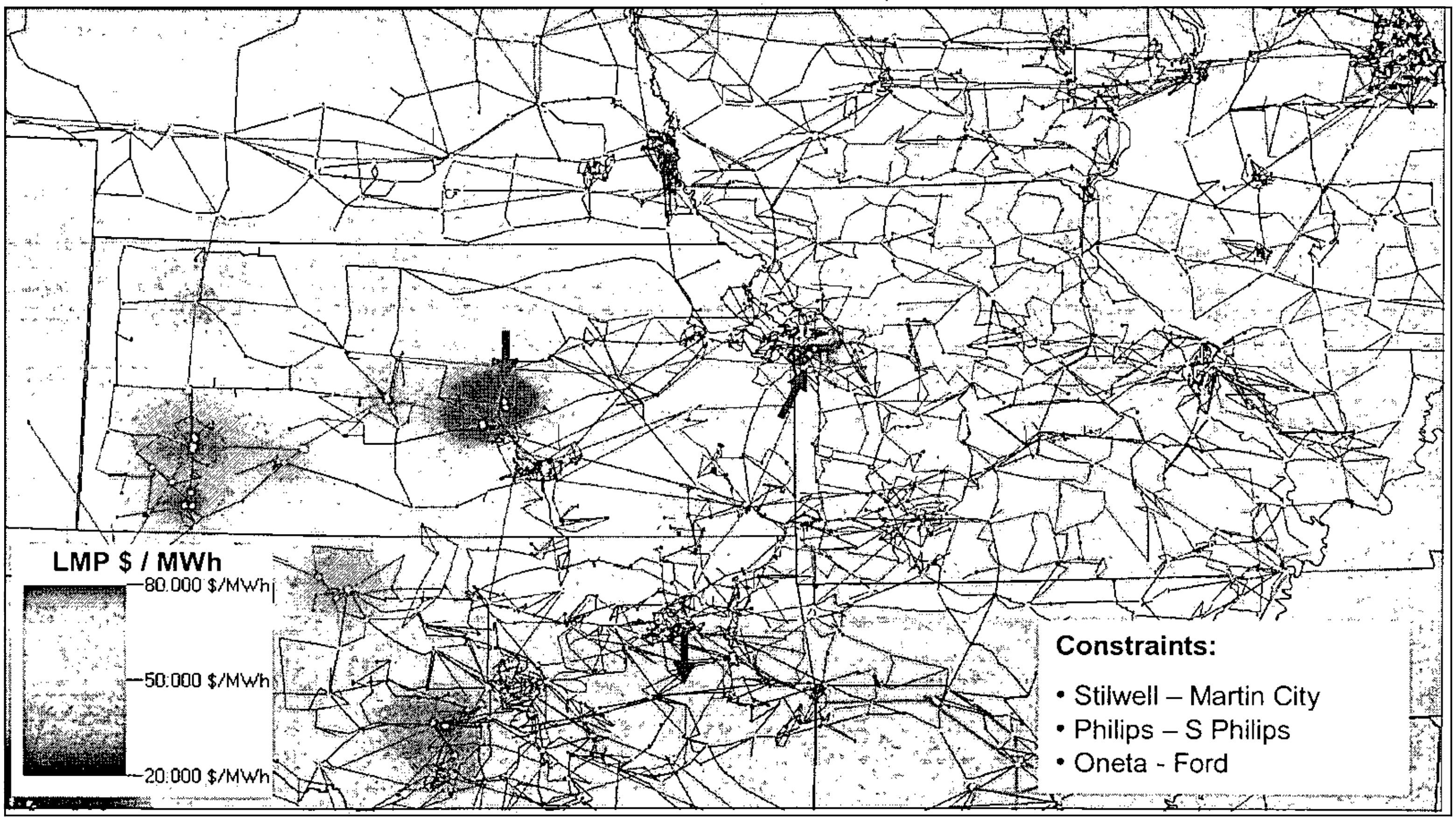

Figure IV - 4

In MISO Constraints & Price Profiles August 14 Hour 17

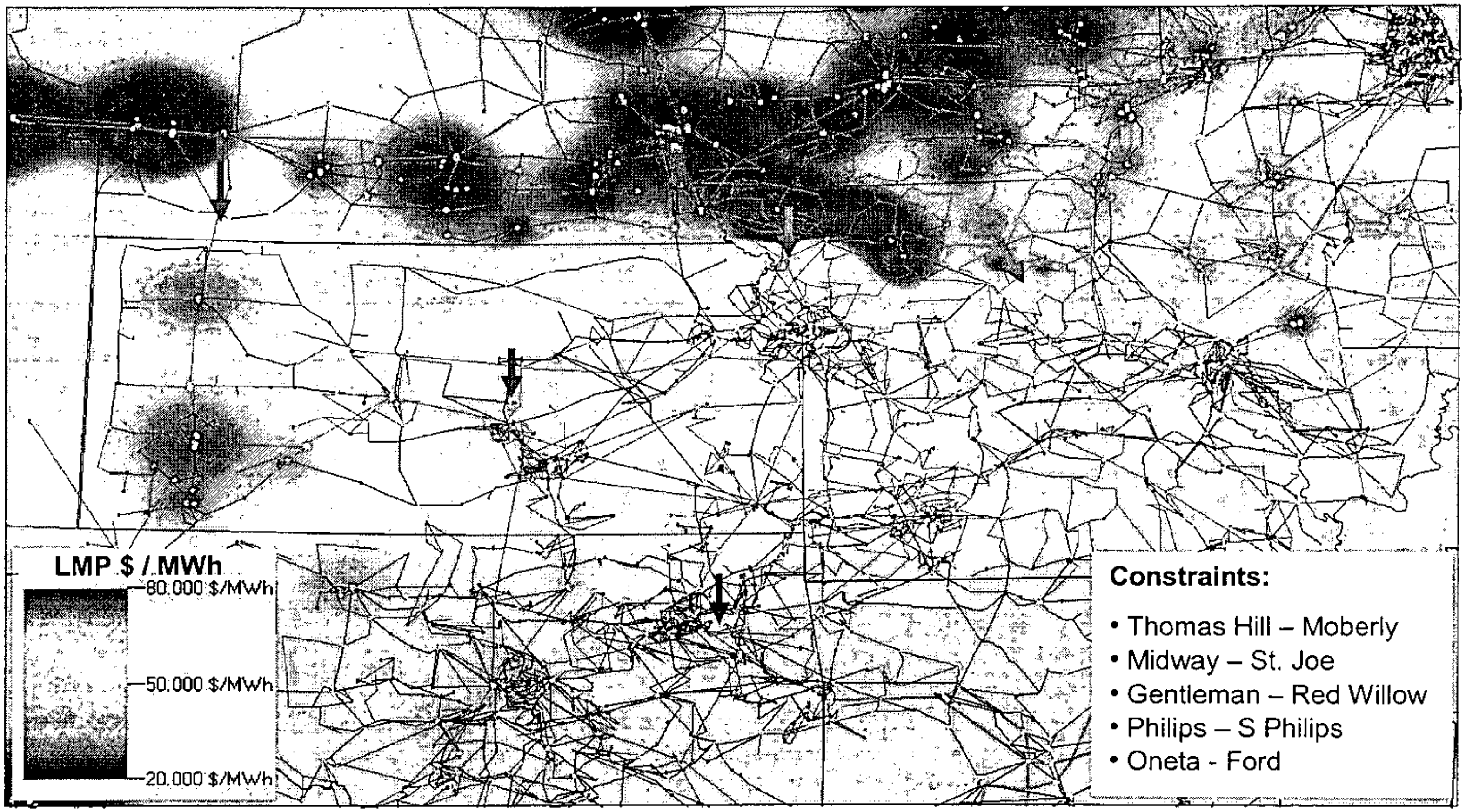

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Figure IV - 5

In MISO Constraints & Prices August 16 Hour 9

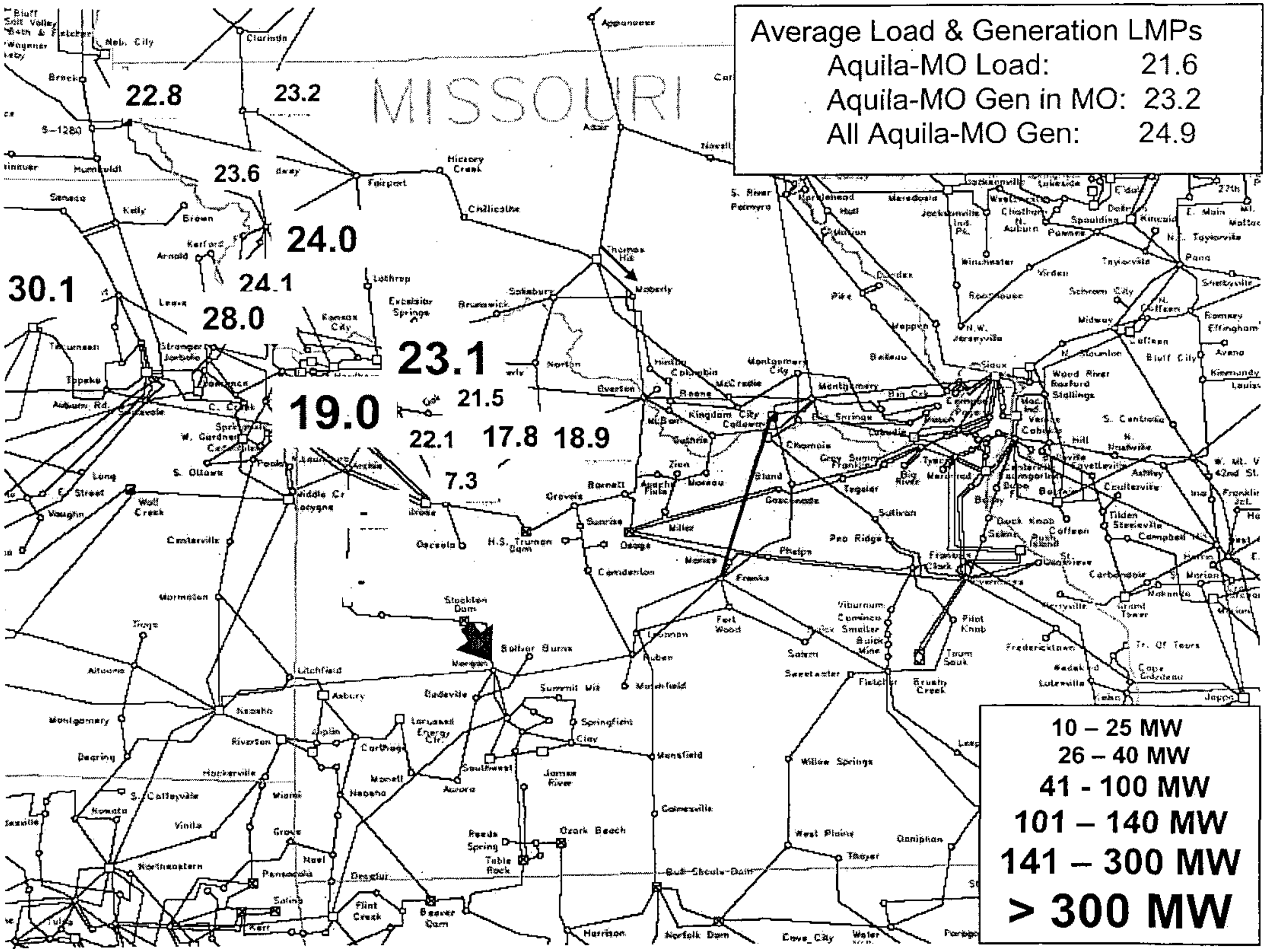

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Figure IV - 6

In SPP Constraints & Prices August 16 Hour 9

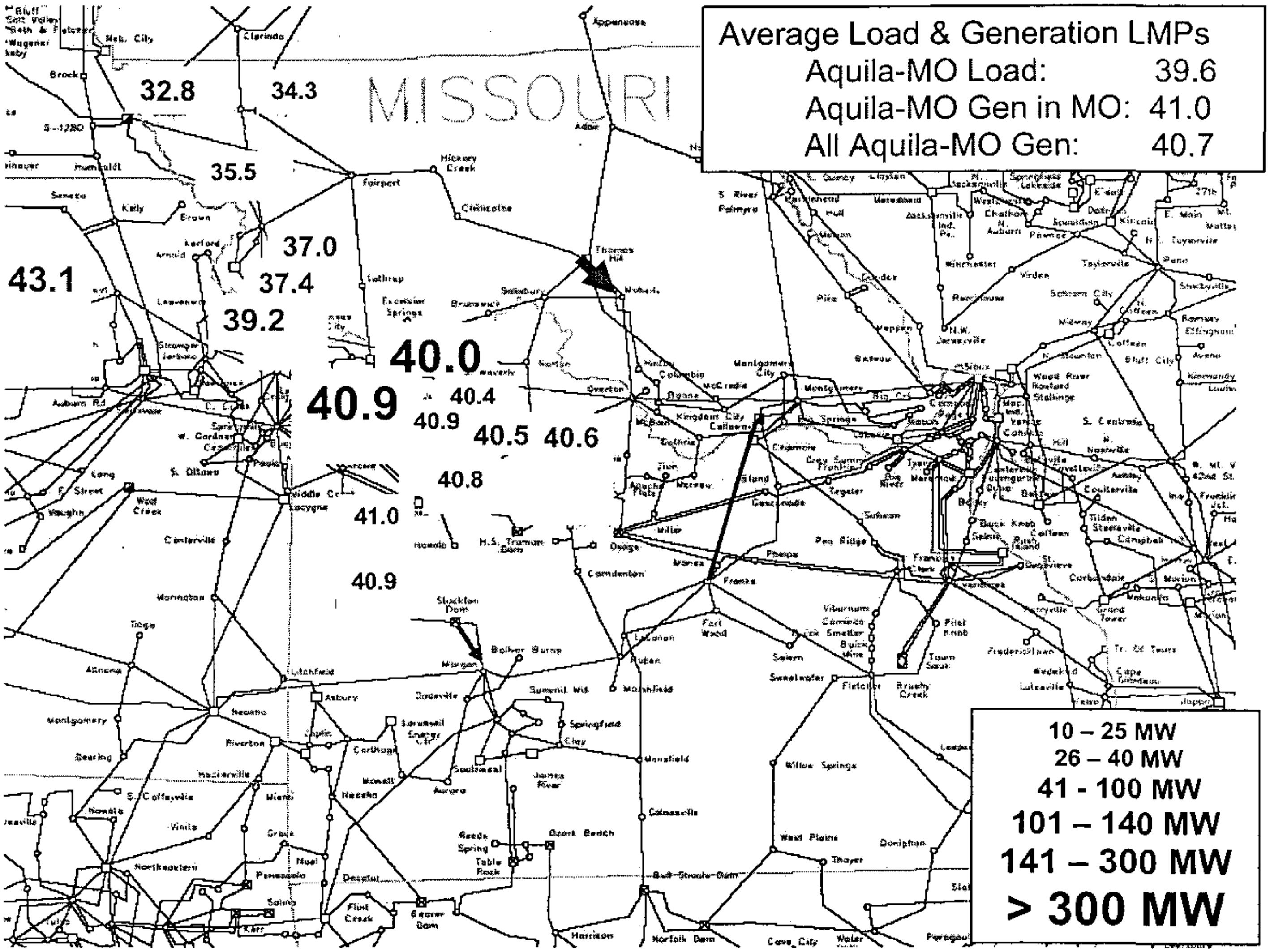

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Figure IV - 7

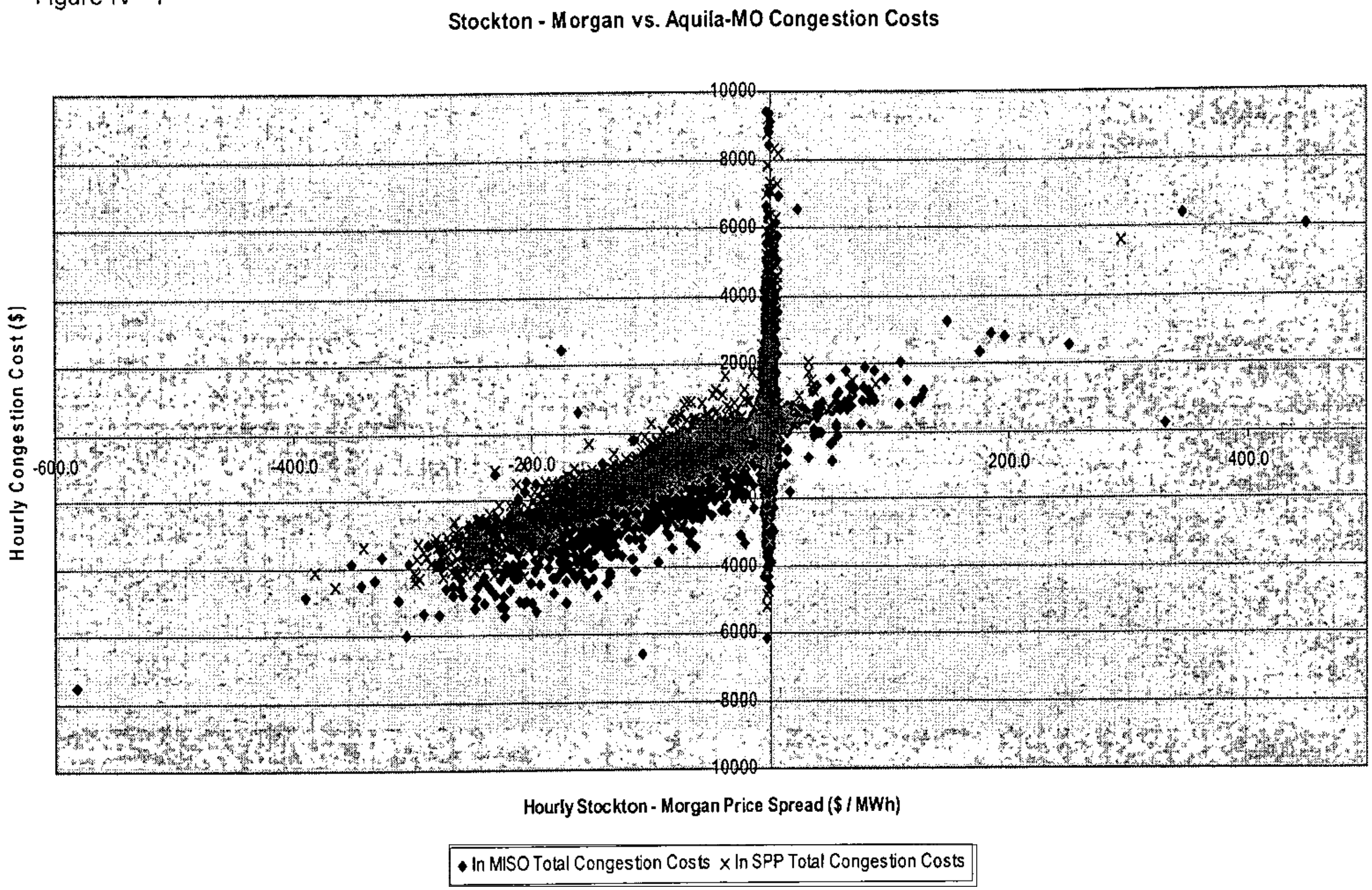

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Table IV – 6
Congestion Costs Summary of Cases - August 15, 2005

Internal Congestion Costs to Serve Aquila-MO Load

Case / Sensitivity	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In MISO	-$3,189,265	-$3,562,828	-$1,988,759	-$3,872,089
In SPP	$2,469,209	$2,230,005	$2,498,098	$2,619,185
Stand Alone	$2,856,438	$2,409,547	$2,631,015	$3,118,714

Costs in Excess of MISO Congestion Costs

	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In SPP	$5,658,474	$5,792,832	$4,486,857	$6,491,274
Stand Alone	$6,045,702	$5,972,374	$4,619,774	$6,990,803

f. *Wholesale Market Prices*

For the reasons described in Section IV b, we have included a quantification of the cost to serve load at wholesale market prices. This is a useful indicator of the economic value of regional security-constrained unit commitment and economic dispatch. It reflects average Aquila-MO hourly load zone prices multiplied by its generation requirements to serve native load. Viewed by this measure, participation in the Midwest ISO would be substantially less costly than either of the remaining options. Membership in SPP produced the highest costs, $38.5 million per year more than Midwest ISO costs. Using this measure, the Stand Alone option is $26.8 million per year more expensive than the Midwest ISO alternative.

Our findings that the cost to serve load at wholesale market prices are substantially lower in the Midwest ISO is consistent across the scenarios that we analyzed. Table IV – 7 summarizes average Aquila-MO load zone prices and the cost to serve native load at wholesale prices for each scenario.

There are several factors that contribute to Aquila-MO enjoying lower wholesale prices in the Midwest ISO: the extent to which gas-fired capacity sets higher prices in SPP, transmission charges and inefficiencies in bilateral trading that keep Aquila-MO prices from rising to SPP levels, improved access to low cost generation when Aquila-MO is in the Midwest ISO, a more favorable match with Midwest ISO resources and loads, lower congestion costs, and the treatment of marginal losses in Midwest ISO energy prices.

In SPP, Aquila-MO's LMPs closely track the prices in the neighboring KCPL control area. KCPL average prices range from $0.08 per MWh to only $0.62 per MWh higher than prices in Aquila-MO. When Aquila-MO is in SPP, there is no transmission charge to move power between Aquila and the other SPP members. With few transmission constraints between Aquila-MO and KCPL, Aquila-MO prices in SPP rise nearly to the level observed in KCPL. However, when Aquila-MO is in the Midwest ISO or operating on a Stand Alone basis, tariff charges and the costs of bilateral transactions tend to keep Aquila-MO prices from converging toward higher KCPL prices. Non-firm transmission charges from Aquila-MO as a Midwest ISO member to KCPL are $4.62/MWh on-peak and $2.47/MWh off-peak. On a stand alone basis, the non-firm transmission rate is $2.59/MWh. In the stand alone case, lower on-peak transmission rates tend to reduce the maximum difference in wholesale prices between Aquila-MO and KCPL. Figure IV- 8 compares monthly average KCPL and Aquila-MO LMPs.

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In response to higher prices, Aquila-MO operates additional higher cost generation and makes more off-system sales in SPP. And, when Aquila-MO is in SPP, it provides an economic path for power sales from MidAmerican Energy into SPP. Prices are often sufficiently higher in SPP than in MidAmerican to pay for transmission service into Aquila, but not high enough to pay the pancaked transmission charges when Aquila-MO is not in SPP from MidAmerican through an intermediate transmission provider and then into SPP. Mid-American Energy's projected off-system sales increase from 2,734,700 MWh when Aquila-MO is in the Midwest ISO, to 2,958755 MWh with Aquila-MO operating on a stand alone basis with lower transmission charges, and to 3,144,939 MWh with Aquila-MO in SPP. As Mid-American sales increase, it will tend to operate more expense units to support off-system sales.

Some of the benefits of participating in the Midwest ISO are attributable to the Midwest ISO's use of marginal losses in setting prices.[18] Table IV – 7 includes breakout overall wholesale price benefits of the Midwest ISO's consideration of marginal losses in setting wholesale prices. For the base case, $21.1 million of savings in the cost to serve Aquila-MO load at wholesale prices are attributable the Midwest ISO's use of marginal losses in setting energy prices. These results are based upon a case in which marginal losses were considered in Midwest ISO unit commitment and dispatch.

The Midwest ISO reflects the cost of replacing the marginal transmission losses associated with additional energy production at the specific location when calculating prices. In the portion of the region where Aquila-MO is located, the consideration of marginal losses tends to reduce the value for generating more energy in this part of the grid and therefore tends to depress LMPs. This is consistent with the loss impacts of a west to east flow of power across the region. Our modeling results permit us to break out this impact by calculating hypothetical prices for the Midwest ISO and restating the results as if the Midwest ISO calculated locational prices without a loss component. When we restate the results using these hypothetical prices for the Midwest ISO, the Midwest ISO retains a significant, but smaller cost advantage. Calculating the cost to serve native load with these restated prices that do not consider losses, the SPP option is $16.4 million more expensive per year that the Midwest ISO option and the Stand Alone option cost $4.7 million more expensive than participation in the Midwest ISO. The remaining advantage of the Midwest ISO option at these restated prices reflects a difference in the generation setting

[18] In its recent Order rejecting the SPP EIS tariff, FERC says that, "Since marginal losses can provide efficient price signals, we encourage SPP to reevaluate at each future phase in its development the decision to use average losses instead of marginal losses." However, the FERC has not required SPP or other RTOs to use marginal losses. *Southwest Power Pool,* 112 FERC ¶61,303 at P 23 (September 19, 2005).

prices, access to lower cost Midwest ISO member resources, integration of Aquila-MO into Midwest ISO transmission operations, lower congestion costs, and participating in a more efficient regional unit commitment and dispatch.

Table IV – 7
Cost to Serve Aquila-MO Load at Wholesale Market Prices - August 15, 2005

Average Wholesale Prices at Aquila-MO Load Locations ($/MWh)				
Case / Sensitivity	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In MISO	$27.09	$27.09	$24.02	$30.13
In SPP	$31.95	$31.97	$28.65	$35.20
Outside of an RTO	$30.47	$30.47	$27.22	$33.76

Cost to Serve Load at Wholesale Market Prices ($)				
Case / Sensitivity	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In MISO	$214,936,733	$214,916,626	$190,569,483	$238,994,840
In SPP	$253,440,023	$253,608,996	$227,280,192	$279,250,803
Stand Alone	$241,724,582	$241,707,130	$215,970,920	$267,845,542

Costs to Serve Load in Excess of Costs at Whole Sale Prices in MISO ($)				
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In SPP	$38,503,290	$38,692,370	$36,710,709	$40,255,963
Stand Alone	$26,787,849	$26,790,504	$25,401,437	$28,850,702

Break Out of Costs in Excess of Costs at Whole Sale Prices in MISO ($)				
	Base Case	Low Hurdle Rates	Low Fuel Cost	High Fuel Cost
In SPP - Related to MISO Loss Treatment	$22,101,038	$21,724,496	$24,176,583	$21,127,935
In SPP - Related to Regional Integration	$16,402,252	$16,967,874	$12,534,126	$19,128,028
Stand Alone - Related to MISO Loss Treatment	$22,101,038	$21,724,496	$24,176,583	$21,127,935
Stand Alone - Related to Regional Integration	$4,686,811	$5,066,008	$1,224,854	$7,722,767
Hypothetical Midwest ISO LMPs without Losses	29.88	29.83	27.07	32.79
In MISO Costs at Hypothetical LMPs without Losses	$237,037,771	$236,641,122	$214,746,066	$260,122,775

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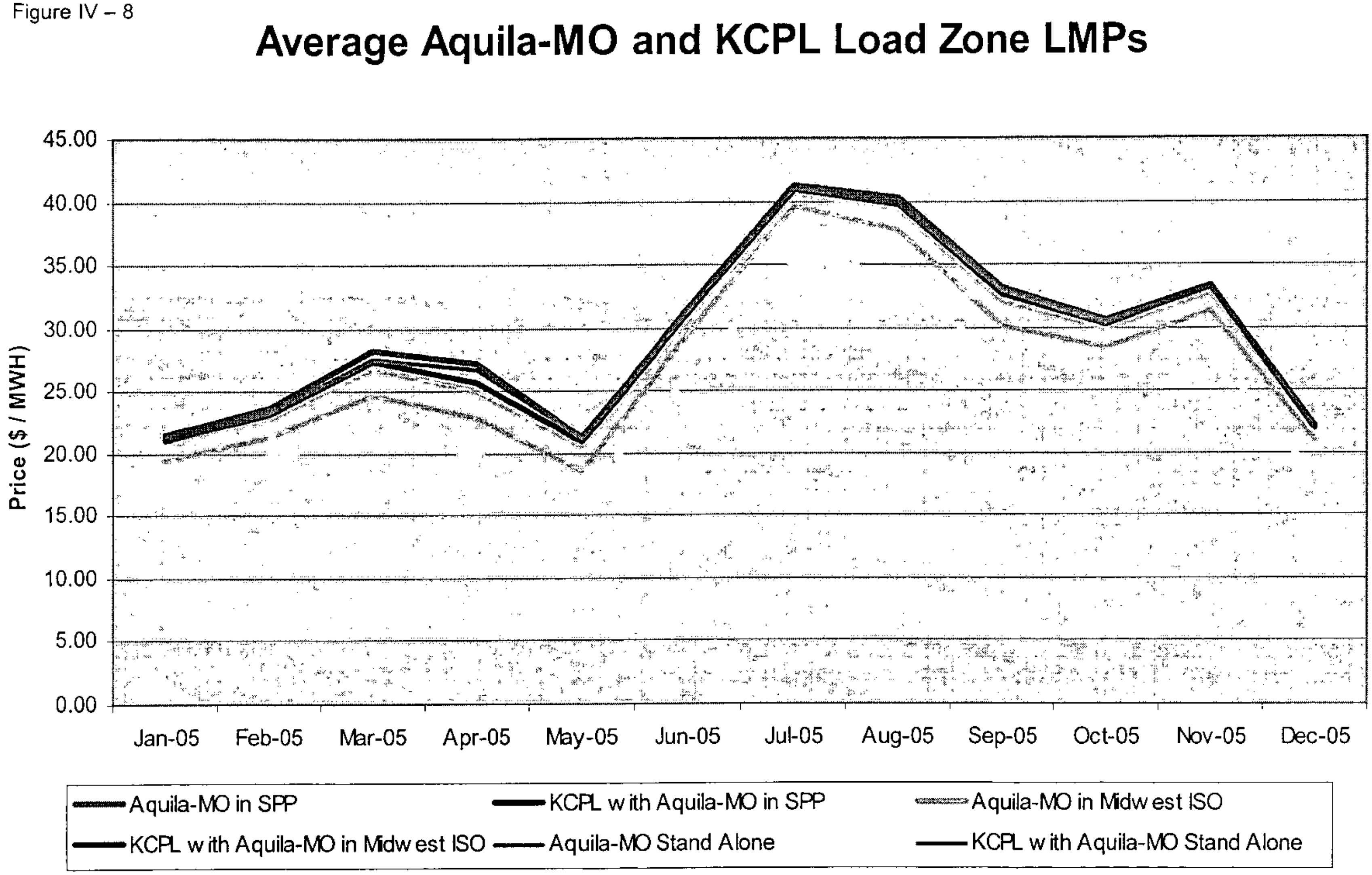
Figure IV – 8



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g. *Regional Through and Out Transmission Rates*

The FERC has done away with regional through and out transmission rates (RTOR) for new transactions between the Midwest ISO and PJM because of the region's unique history of RTO formation and overlapping seams that effectively cut off parts of each RTO within the borders of the other.[19] FERC explained:

> Order No. 2000 indicates that, among the factors that will be considered when determining appropriate RTO configuration, the Commission will consider the extent to which the proposal would encompass one contiguous area, encompass a highly interconnected portion of the grid, and recognize trading patterns. When we find that a proposed RTO does not meet the scope and configuration requirements of Order No. 2000, as we did with respect to the organizations resulting from certain former Alliance Companies' decisions to join PJM, the Commission must impose conditions on its acceptance of those decisions, such as requiring inter-RTO coordination agreements and/or the elimination of inter-RTO rate pancaking, in order to mitigate otherwise inappropriate RTO configuration. While the Commission has not required the elimination of inter-RTO rate pancaking before, the Commission has not had to address the issue before; the circumstances presented in this proceeding are *unprecedented*.[20]

The seams issues and trading patterns between the Midwest ISO and SPP are different than those between the Midwest ISO and PJM; and it is not at all clear that Midwest ISO – SPP RTOR will disappear with the implementation of SPP's EIS market. Nonetheless, questions were asked about whether Aquila-MO could be in SPP and enjoy benefits comparable to those associated with membership in the Midwest ISO in the absence of RTOR between SPP and the Midwest ISO. To address this question, we evaluated a case in which Aquila-MO is in SPP and we assumed termination of the Midwest ISO – SPP RTOR. Compared to the Aquila-MO in MISO base case, removing RTOR mitigates, but does not eliminate the additional costs associated with membership in the SPP RTO. Table IV – 8 compares the Base Case with Aquila-MO in the Midwest ISO to both an SPP case without the Midwest ISO – SPP RTOR and the Base Case with Aquila-MO in SPP.

Table IV - 8
Aquila-MO in SPP with and without Midwest ISO - SPP RTOR

Perspective / Case	Aquila in Midwest ISO Base Case	Aquila-MO in SPP with No RTOR	Aquila-MO in SPP Base Case
Utility Production & Purchased Power Costs	$148,053,013	$150,436,103	$151,362,024
Congestion Costs	-$3,189,265	$1,671,067	$2,469,209
Cost to Serve Load at Wholesale Prices	$214,936,733	$239,874,600	$253,440,023

[19] *Midwest Independent Transmission System Operator,* 104 FERC ¶ 61,105 (July 23, 2003). (Emphasis added.)
[20] *Id.* at P 29.

h. *Comparison Tables*

Tables IV – 9 through IV – 12 compare the results of the Aquila-MO in Midwest ISO, in SPP, and Stand Alone cases for each or our scenarios, respectively the Base Case, Low Hurdle Rate, Low Fuel Cost, and High Fuel Cost Scenarios. Each table summarizes projected production and purchased power costs by month. The cost to support off-system sales is then deducted from total production and purchased power costs to calculate the net monthly cost to serve native load customers. To the right of the column labeled "Cost to Serve Aquila-MO Native Load", is a column containing monthly off-system sales revenues and a second column which calculates total production and purchased power costs (from the initial columns to the left) less off-system sales revenue. Finally, each table provides a monthly breakdown of congestion costs. Congestion costs are calculated relative to a common reference bus used in all of the cases.

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Table IV - 9
Base Case Cost and Revenue Monthly Detail - August 15, 2005

Aquila-MO in Midwest ISO

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Production & Purchased Power Costs Less Off-System Sales Revenue	Co
January	7,374,355	4,491,930	-679,968	11,186,317	-805,966	11,060,319	
February	7,343,259	3,960,605	-956,958	10,346,905	-1,321,325	9,982,538	
March	7,822,227	3,540,944	-554,704	10,808,467	-905,461	10,457,709	
April	7,125,282	3,768,575	-1,712,235	9,181,622	-2,484,813	8,409,044	
May	6,768,384	4,334,122	-964,463	10,138,043	-1,086,484	10,016,022	
June	6,423,798	9,112,468	-373,660	15,162,606	-414,419	15,121,847	
July	7,267,723	13,527,630	-298,924	20,496,428	-342,951	20,452,401	
August	7,204,565	12,018,305	-343,909	18,878,960	-399,312	18,823,557	
September	7,198,410	6,006,607	-912,597	12,292,420	-1,205,364	11,999,653	
October	7,006,872	3,644,532	-1,206,452	9,444,952	-1,790,318	8,861,087	
November	5,301,711	6,839,775	-562,201	11,579,285	-798,947	11,342,539	
December	4,845,166	6,996,082	-285,501	11,555,748	-314,952	11,526,297	
Total	**$81,681,752**	**$78,241,574**	**-$8,851,572**	**$151,071,754**	**-$11,870,313**	**$148,053,013**	**-$**

Aquila-Mo in SPP

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Control Area Load	Con Cos
January	7,949,301	4,461,131	-928,253	11,482,179	-1,197,483	11,212,950	
February	8,064,665	3,855,775	-1,250,414	10,670,026	-1,898,915	10,021,525	
March	8,897,638	3,427,972	-993,773	11,331,838	-1,673,933	10,651,678	
April	7,463,967	3,827,362	-2,005,425	9,285,904	-3,188,011	8,103,318	
May	7,884,490	4,016,675	-1,558,623	10,342,542	-1,998,457	9,902,707	
June	6,691,410	9,784,377	-591,299	15,884,488	-720,679	15,755,108	
July	7,824,756	14,358,244	-478,225	21,704,775	-605,316	21,577,684	
August	7,382,035	12,932,816	-517,370	19,797,481	-664,081	19,650,770	
September	7,414,348	6,303,053	-1,163,155	12,554,247	-1,723,905	11,993,497	
October	7,135,642	3,762,885	-1,327,143	9,571,384	-2,064,999	8,833,528	
November	5,334,756	7,346,851	-639,850	12,041,757	-1,037,755	11,643,851	
December	5,087,703	7,461,692	-446,814	12,102,582	-533,989	12,015,407	
Total	**$87,130,713**	**$81,538,833**	**-$11,900,344**	**$156,769,202**	**-$17,307,522**	**$151,362,024**	**$**

Stand Alone Operations

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Control Area Load	Co
January	7,804,673	4,218,494	-545,930	11,477,236	-650,299	11,372,867	
February	7,826,513	3,559,881	-709,380	10,677,014	-1,100,093	10,286,301	
March	8,901,981	3,152,210	-629,184	11,425,007	-1,059,986	10,994,205	
April	7,401,317	3,458,605	-1,254,514	9,605,408	-1,840,401	9,019,522	
May	7,173,749	3,744,046	-611,436	10,306,359	-704,322	10,213,473	
June	6,551,559	9,640,870	-313,669	15,878,759	-343,687	15,848,741	
July	7,758,754	14,249,466	-296,399	21,711,821	-332,270	21,675,950	
August	7,236,014	12,686,276	-267,977	19,654,313	-303,293	19,618,997	
September	7,069,405	6,080,662	-571,134	12,578,933	-822,067	12,328,001	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	

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Table IV - 10
Low Hurdle Rate Scenario Cost and Revenue Monthly Detail - August 15, 2005

Aquila-MO in Midwest ISO

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Production & Pu Power Costs Less C Sales Revenue
January	7,298,593	4,528,806	-617,732	11,209,667	-736,177	
February	7,247,171	3,956,842	-849,324	10,354,689	-1,189,799	
March	7,823,641	3,547,545	-543,772	10,827,415	-900,812	
April	7,122,325	3,780,800	-1,724,273	9,178,852	-2,509,344	
May	6,668,516	4,356,196	-877,091	10,147,621	-989,764	
June	6,400,840	9,130,386	-347,137	15,184,089	-386,059	
July	7,265,246	13,575,443	-291,415	20,549,274	-328,190	
August	7,212,849	12,035,381	-330,502	18,917,728	-382,447	
September	7,192,447	5,990,254	-903,552	12,279,149	-1,179,009	
October	6,989,756	3,647,654	-1,181,893	9,455,517	-1,765,531	
November	5,301,383	6,857,087	-560,242	11,598,228	-800,474	
December	4,823,925	6,989,273	-271,893	11,541,305	-300,451	
Total	**$81,346,692**	**$78,395,667**	**-$8,498,826**	**$151,243,533**	**-$11,468,058**	

Aquila-Mo in SPP

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve C Load
January	7,957,288	4,465,617	-937,549	11,485,355	-1,213,771	
February	8,125,688	3,835,801	-1,246,725	10,714,764	-1,925,900	
March	9,276,849	3,283,448	-1,036,677	11,523,619	-1,792,167	
April	7,506,967	3,825,699	-2,028,092	9,304,574	-3,215,408	
May	7,875,741	4,046,446	-1,555,304	10,366,883	-1,973,148	
June	6,654,488	9,787,621	-561,246	15,880,862	-682,513	
July	7,513,762	14,612,047	-476,250	21,649,558	-589,344	
August	7,391,334	12,960,673	-519,963	19,832,044	-655,602	
September	7,425,143	6,289,501	-1,178,733	12,535,911	-1,750,678	
October	7,147,804	3,773,096	-1,358,358	9,562,541	-2,101,742	
November	5,335,620	7,333,861	-645,672	12,023,809	-1,049,042	
December	5,069,898	7,475,651	-438,327	12,107,222	-513,930	
Total	**$87,280,581**	**$81,689,459**	**-$11,982,896**	**$156,987,144**	**-$17,463,244**	

Stand Alone Operations

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve C Load
January	7,819,776	4,256,799	-576,945	11,499,630	-701,864	
February	8,036,869	3,528,576	-741,886	10,823,559	-1,197,916	
March	9,203,013	3,068,455	-648,557	11,622,911	-1,130,489	
April	7,318,220	3,489,615	-1,289,467	9,518,367	-1,941,336	
May	7,314,466	3,745,242	-647,247	10,412,461	-772,670	
June	6,545,019	9,655,286	-315,321	15,884,984	-347,187	
July	7,451,540	14,460,129	-298,608	21,613,061	-335,670	

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Table IV - 11
Low Fuel Cost Scenario Cost and Revenue Monthly Detail - August 15, 2005

Aquila-MO in Midwest ISO

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Production & Pu Power Costs Less O Sales Revenue
January	7,353,553	4,485,204	-$711,311	11,127,445	-853,048	
February	7,366,770	3,933,780	-$1,080,867	10,219,684	-1,448,986	
March	7,803,462	3,419,087	-$652,934	10,569,615	-936,145	
April	7,189,994	3,798,408	-$1,891,776	9,096,626	-2,648,100	
May	6,911,396	4,252,993	-$1,207,259	9,957,130	-1,383,889	
June	6,488,943	8,137,152	-$442,877	14,183,217	-494,928	
July	7,294,401	11,607,939	-$357,150	18,545,190	-411,307	
August	7,194,956	10,335,902	-$414,972	17,115,887	-484,698	
September	7,288,347	5,482,890	-$1,024,985	11,746,252	-1,326,074	
October	7,050,225	3,552,558	-$1,270,164	9,332,619	-1,809,278	
November	5,299,757	6,218,385	-$588,506	10,929,636	-823,127	
December	4,916,768	6,751,391	-$316,919	11,351,240	-360,653	
Total	**$82,158,573**	**$71,975,688**	**-$9,959,720**	**$144,174,541**	**-$12,980,233**	

Aquila-Mo in SPP

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Cc Load
January	7,993,549	4,406,006	-$990,278	11,409,277	-1,259,124	
February	8,137,683	3,767,703	-$1,346,744	10,558,642	-1,949,662	
March	8,854,477	3,334,297	-$1,067,095	11,121,679	-1,684,228	
April	7,551,026	3,809,257	-$2,087,714	9,272,569	-3,238,089	
May	8,116,524	3,982,376	-$1,789,917	10,308,984	-2,332,460	
June	6,713,713	8,820,560	-$627,925	14,906,348	-760,838	
July	7,843,255	12,422,768	-$481,648	19,784,375	-603,400	
August	7,396,668	11,287,180	-$543,949	18,139,898	-685,882	
September	7,467,007	5,818,340	-$1,238,184	12,047,163	-1,795,049	
October	7,176,617	3,644,387	-$1,389,492	9,431,512	-2,046,452	
November	5,333,680	6,676,328	-$645,299	11,364,709	-997,497	
December	5,093,235	7,221,929	-$466,467	11,848,697	-556,326	
Total	**$87,677,434**	**$75,191,132**	**-$12,674,712**	**$150,193,854**	**-$17,909,007**	

Stand Alone Operations

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Cc Load
January	7,833,616	4,171,297	-$593,144	11,411,769	-702,738	
February	7,836,238	3,536,837	-$821,228	10,551,847	-1,189,768	
March	8,713,004	3,126,117	-$692,407	11,146,714	-1,058,812	
April	7,155,820	3,546,259	-$1,395,963	9,306,116	-1,949,248	
May	7,361,751	3,670,117	-$762,371	10,269,497	-909,158	
June	6,590,719	8,671,631	-$343,139	14,919,210	-376,762	
July	7,793,746	12,281,448	-$317,544	19,757,649	-359,091	

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Table IV - 12
High Fuel Cost Scenario Cost and Revenue Monthly Detail - August 15, 2005

Aquila-MO in Midwest ISO

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Production & Purc Power Costs Less Off- Sales Revenue
January	7,324,429	4,563,599	-$615,079	11,272,949	-744,548	
February	7,394,093	4,011,599	-$905,044	10,500,648	-1,303,918	
March	7,741,922	3,674,540	-$493,966	10,922,495	-915,680	
April	7,018,469	3,778,185	-$1,560,574	9,236,080	-2,355,416	
May	6,731,726	4,411,144	-$824,181	10,318,689	-940,836	
June	6,412,500	10,090,986	-$344,368	16,159,118	-377,540	
July	7,270,333	15,409,610	-$269,192	22,410,751	-302,127	
August	7,257,078	13,641,335	-$309,217	20,589,196	-354,365	
September	7,160,605	6,495,707	-$863,092	12,793,221	-1,160,711	
October	6,970,877	3,726,606	-$1,152,985	9,544,498	-1,787,331	
November	5,300,026	7,453,225	-$556,875	12,196,376	-808,650	
December	4,818,750	7,194,577	-$270,880	11,742,447	-298,897	
Total	**$81,400,808**	**$84,451,113**	**-$8,165,453**	**$157,686,468**	**-$11,350,019**	**$'**

Aquila-Mo in SPP

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Con Load
January	8,008,477	4,514,101	-$920,668	11,601,909	-1,207,698	
February	8,182,964	3,921,003	-$1,241,834	10,862,134	-1,949,238	
March	9,286,229	3,396,275	-$984,884	11,697,621	-1,785,401	
April	7,641,075	3,805,009	-$1,997,634	9,448,450	-3,291,977	
May	7,841,005	4,123,651	-$1,472,685	10,491,971	-1,836,174	
June	6,680,945	10,695,586	-$558,508	16,818,023	-679,545	
July	7,735,953	16,183,220	-$443,735	23,475,438	-545,880	
August	7,386,008	14,545,139	-$492,817	21,438,330	-620,597	
September	7,391,186	6,832,455	-$1,126,967	13,096,674	-1,706,208	
October	7,120,800	3,883,981	-$1,315,960	9,688,821	-2,124,980	
November	5,335,495	7,841,048	-$643,656	12,532,887	-1,057,981	
December	5,082,042	7,716,514	-$434,747	12,363,809	-516,666	
Total	**$87,692,179**	**$87,457,983**	**-$11,634,095**	**$163,516,067**	**-$17,322,344**	**$'**

Stand Alone Operations

Month	Generation Costs	Purchased Power Costs	Less: Cost of Off-System Sales	Cost to Serve Aquila-MO Native Load	Less: Revenue from Off-System Sales Net of Transmission Charges	Net Cost to Serve Con Load
January	7,879,779	4,280,937	-$537,832	11,622,884	-660,326	
February	7,867,891	3,605,714	-$646,396	10,827,209	-1,082,758	
March	9,177,375	3,174,439	-$591,416	11,760,398	-1,136,805	
April	7,364,995	3,438,700	-$1,139,928	9,663,767	-1,774,966	
May	7,353,781	3,780,361	-$566,657	10,567,485	-650,273	
June	6,548,827	10,590,135	-$285,939	16,853,023	-314,378	
July	7,635,990	16,074,752	-$266,974	23,443,768	-295,711	
August	7,258,153	14,354,625	-$245,715	21,367,063	-275,565	
September	7,056,418	6,508,768	-$535,126	13,130,050	-780,228	

V. Qualitative Considerations

Our quantitative analysis evaluated how Aquila-MO would perform under each RTO option holding market participant behavior constant, assuming comparable reliability, and without evaluating the impact of longer-term incentives. We also modeled the SPP EIS market as if it supported market based congestion management equivalent to the Midwest ISO's real-time energy market. Such simplifying assumptions were needed to conduct the analysis. However, it is important to place that quantitative analysis in context. The three options are not equivalent to one another.

The following qualitative discussion is designed to highlight differences between options that otherwise might not be immediately apparent.

- SPP's EIS market design has not been approved by the FERC. We will discuss the recent FERC Order rejecting SPP's proposed EIS tariff and the issues identified in that Order. SPP is expected to address these concerns in future filings at the Commission.
- SPP's EIS combines elements of traditional transmission rights with locational pricing when an "imbalance" is created. Differences between this approach and the LMP markets used in the Midwest ISO and other RTOs have potential implications for market participant behavior. We will discuss risks associated with two potential behaviors that could be detrimental to Aquila-MO or other SPP participants.
- Our understanding is that SPP's EIS proposal is not identical from a dispatch and reliability perspective to the security-constrained unit commitment and dispatch within the Midwest ISO. We will identify differences.
- RTO energy markets make transparent information about the time- and location-specific value of energy and capacity. We will examine how such information can change performance incentives and the quality of regulation.

These considerations are directionally consistent with our quantitative findings in that they suggest that there may be additional risks associated with the SPP market design and that there are potentially large longer-term benefits associated with membership in an RTO with a transparent market for energy and transmission rights.

a. *FERC Order on SPP's EIS Tariff*

On September 19, 2005, the FERC rejected SPP's proposed EIS tariff. The Commission's order calls the proposal "inadequate in several respects" and provides guidance on "key elements" related to: reliable and stable market operations, market-based rate authority, and market power mitigation and market monitoring.[21] The order also requires SPP to file additional information clarifying the relationship of the EIS market to up to 417 grandfathered transmission agreements (GFAs) and the treatment of transmission owners' bundled retail service. The Order describes ambiguities in SPP's tariff and risks related to the design of the EIS market.

FERC identifies issues that we encountered in analyzing the proposed EIS market. In our quantitative analysis, we assumed that these issues would be favorably resolved in a manner that tended to optimize the efficiency of the EIS market. For example, we assumed in the quantitative analysis that suppliers would submit offers for all of their generation in the EIS market, even though there is no requirement that they do so and in some circumstances will be incentives to self-schedule and not offer into the EIS market.

The Commission identified numerous issues related to SPP's ability to ensure reliable and stable operation of the EIS market. These included:

- *Failure to specify rules for the interaction of the imbalance market and the TLR process.* The Commission also notes that SPP has not provided "a full picture of these two simultaneously implemented processes" or explained how they will impact rates in the imbalance market.[22]
- *Inconsistency of an EIS market that is voluntary for sellers and mandatory for buyers with the absence of provisions (short of emergency procedures) to address insufficient seller participation.* The Commission addresses this concern in both a reliability and a congestion management context. First, the lack of seller obligations (e.g. must offer or reliability based commitment requirements) "raises concerns that there might not be adequate local generation ... creating reliability concerns." Second, another concern raised by the voluntary suppliers' market is that "most generation will be self-dispatched resulting in insufficient energy bids in the market to allow SPP to resolve congestion through economic dispatch."[23] Self-dispatch would limit the ability of SPP to use market mechanisms to manage congestion in the transmission system. In its earlier approval of SPP's RTO status the Commission noted that, "an RTO must ensure the development and operation of market mechanisms to manage transmission congestion. The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the

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[21] *Southwest Power Pool,* 112 FERC ¶61,303 (September 19, 2005).
[22] *Id.* at P 24.
[23] *Id.* at P 26.

consequences of their transmission usage decisions."[24] It is not clear to what extent the EIS market will become an effective market mechanism for managing congestion.

- *Lack of a tariff process for evaluating resource and ancillary services plans.* EIS market participants would submit resource and ancillary service plans, including plans for the dispatch of network resources and provision of operating reserves, on a day-ahead basis. At that time, SPP intends to run a Simultaneous Feasibility Test (SFT) to determine whether the submitted plans can be implemented. Market participants may modify their resource and ancillary service plans at any time up to 30 minutes prior to the start of the Operating Hour. The Commission found that the tariff should include the process for evaluating these plans and, "Importantly, SPP should clarify how it will resolve conflicts when plans are deemed to fail the simultaneous feasibility tests in either [the day-ahead or 30-minute prior to operating hour] time periods and detail market participants' obligations to follow SPP's instructions in this regard." [25] Ambiguity regarding the evaluation of such plans could raise concerns related to reliability (e.g. a lack of reserve capacity committed in areas where it may be needed); the congestion impacts of network and GFA resources; and uncertainty regarding financial consequences for EIS market participants.
- *Under- and over-scheduling penalties will limit use of the imbalance market or create poor incentives for suppliers to offer energy into the market.* SPP has proposed penalties for the purpose of counteracting incentives to under-schedule counterflows and over-schedule in order to hoard valuable transmission rights. The Commission expressed concern that in some scenarios the penalties might not be adequate. For example, if the price at a market participant's load hub exceeded the price at its generation node, that participant could over schedule a constraining transmission facility without penalty if its actual generation does not deviate from its schedule. Such a strategy could be used to deny other suppliers use of a congested transmission path. And, it directed SPP ensure these penalties not discourage participation in the market or encourage dispatch of uneconomic resources to avoid penalties.[26]
- *Failure to explain any additional functions of scheduling provisions.* SPP may intend transmission schedules to serve as a tool for hedging congestion costs. The Order indicates that SPP "should fully explain how such a mechanism would work." [27] Given that each market participant can modify its schedules up to 30 minutes prior to the start of the operating hour and a failure to specify how SPP will treat schedules that fail a SFT, it

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[24] *Southwest Power Pool, Inc.*, 106FERC ¶ 61,110 at P 133, *order on reh'g*, 109 FERC ¶ 61,010 (2004)
[25] *Southwest Power Pool*, 112 FERC ¶61,303 at P 27 (September 19, 2005).
[26] *Id.* at P 28.
[27] *Id.*

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is not clear that scheduling will provide an effective means for market participants to manage risks associated with congestion costs.

- *Failure to sufficiently address the interaction between the imbalance market, including SPP dispatch instructions, and control area operations.* The Commission directs SPP in future filings to clearly address: the respective obligations of SPP and control areas; liability of control area operators; any cost shifting and compensation that might occur with the EIS market; potential adverse impacts on reliability; and seams issues, if any, resulting from changes in control area responsibilities.[28] It is not difficult to imagine how conflicts might arise between SPP dispatch instructions and control area reliability operations. For example, a control area might identify an emerging problem that requires prompt redispatch to ensure reliability. However, if the problem were identified 25 minutes prior to the start of an operating hour, in the absence of a clear procedure covering such circumstances, it might be an hour and 25 minutes before SPP dispatch instructions began to reflect generator schedules or bids taking the problem into consideration.
- *Failure of the tariff to contain all the provisions that "significantly affect rates and services.* The proposed tariff was found to be inadequate because it did not provide sufficient information for market participants to determine the steps of all the processes that SPP will undertake and the charges that may apply in the EIS market. The Order highlights a lack of information on settlement and other processes.[29] The Commission directs SPP to provide further explanation of its proposed revisions to the calculation of "net scheduled interchange" – a key metric used in managing the stability of the grid. SPP is also directed to include in the tariff its processes for managing the interaction between the EIS market and reserve sharing events and for maintaining accounts related to the inadvertent interchange of energy between control areas.[30]

FERC also addresses whether applicants seeking market-based rates for wholesale power sales can use the area covered by the EIS market as the relevant market for purposes of calculating market power screens. This is potentially important because it is easier to pass the market power screens using a larger regional market and would become easier to qualify for market-based rates. The Commission decided that without centralized unit commitment and with only a portion of generation voluntarily being dispatched in the EIS market, SPP could not be used as the

[28] *Id.* at P 29.
[29] *Id.* at P 25.
[30] *Id.* at P 29.

default market area. The operation of the EIS market may need to be modified to reflect cost-based pricing for participants who have not been approved to sell power at market-based rates.[31]

The Commission also is requiring a series of changes in the roles SPP's Market Monitoring Unit and external Independent Market Monitor and in its market power mitigation practices and procedures.[32] SPP still needs to demonstrate that its market monitoring and mitigation plan is consistent with the Commission's Market Monitoring Policy Statement.[33]

Finally, the Commission directed SPP in its next filing to address the integration of its numerous GFAs with the EIS market.[34] To the extent GFAs are not converted to the SPP Open Access tariff, the extent to which they may be subject to rate terms set by the SPP EIS tariff remains a major open issue.

As of the completion of this report, SPP has not yet filed with the FERC to address to the deficiencies in its original proposal and renew its request for approval for an EIS market.

b. SPP EIS Market Rules: Participant Behavior

We believe at least two risks related to strategic participant behavior are introduced or increased by the design of the SPP EIS market.

i. Expanding Areas of High Prices

The market monitoring plan that SPP filed with the FERC contains an illustration of this problem, but aside from suggesting that the market monitor should be "vigilant," the plan does not propose any specific tests or remedies to identify and mitigate its occurrence.[35] The problem arises when a generator upstream from a constraint self-schedules its power under a transmission reservation that is subject to curtailment under SPP's use of TLR procedures. In such circumstances, the supplier can rely on the TLR curtailments required under SPP's EIS market rules to curtail the dispatch of this generator to the remaining capacity of the constrained flowgate without directly

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[31] *Id.* at P 32 - 34.
[32] *Id.* at P 35 - 58.
[33] *Policy Statement on Market Monitoring Units,* 111 FERC ¶ 61,267 (2005).
[34] *Southwest Power Pool,* 112 FERC ¶61,303 at P 60 (September 19, 2005).
[35] Direct Testimony of Dr. Craig R. Roach, Ph.D. Concerning SPP's Market Power Mitigation Measures On Behalf of Southwest Power Pool Inc., *Southwest Power Pool, Inc.*, FERC Docket No. ER05-1118-000 (June 15, 2005), p. 30-41.

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withholding capacity from the market. The pricing effect, as illustrated in the testimony that the SPP market monitor filed at FERC, can be to extend an area of high prices to additional upstream loads.[36]

This risk could directly impact Aquila-MO when the Companies are in SPP.[37] Aquila-MO load is upstream of the Stockton to Morgan transmission constraint. Kansas City Power & Light, which sells power to Aquila-MO, operates a 510 MW coal plant at Montrose that also is immediately upstream of the Stockton – Morgan constraint. For illustrative purposes, we analyzed a day (June 5, 2005) from our SPP model run on which the Stockton – Morgan constraint was binding in 21 hours. We ran four alternative cases, in which Montrose output was curtailed to different levels and examined what would occur if KCPL could select the most profitable of the four curtailment levels and schedule at least that quantity of Montrose generation under a transmission reservation that would be curtailed by SPP market rules. The result was to increase the cost to serve Aquila-MO load by $15,500 per day or nearly 5%. This example is offered for illustrative purposes. The actual impacts of deliberate strategic behavior could differ.

It may be difficult for the Market Monitor to distinguish between self-scheduling generation for legitimate business reasons such as to support a specific contract and strategic self-scheduling that could increase costs to other market participants. The SPP Market Monitor has not described a mitigation approach for such behavior. And, there is a risk that the Market Monitor will not intervene where such behavior arguably may have been undertaken for a legitimate business reason. This risk is unique to the SPP market design. Under the TEMT, the Midwest ISO relies on its economic dispatch to resolve constraints and rarely uses TLRs to curtail generation within its footprint.

ii. Degradation of Economic Dispatch

In the SPP EIS market, suppliers can modify their schedules and elect to self-schedule generation (by not submitting or withdrawing offers or offer curves) on an hour-by-hour basis up to 30 minutes prior to the start of each operating hour. As long as a specific generator is scheduled under a transmission reservation with a sufficient priority to avoid being subject to a TLR, the supplier can be fully hedged against any congestion costs that its generation may cause.

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[36] *Ibid.* See also the "EIS Market Example" attached to Dr. Roach's testimony.
[37] Access to lower cost resources and the break in prices created by transmission charges at seam between the Midwest ISO and SPP may mitigate this effect if Aquila-MO is in the Midwest ISO.

This is fundamentally different from the use of FTRs to hedge congestion in the Midwest ISO and other RTOs. FTRs are allocated well in advance of the operating hour to which they apply. The holder of the FTR will be paid its value regardless of whether he offers any generation into the Day-Ahead and Real-Time energy markets. If a supplier in the Midwest ISO elects to "self-schedule" a unit by effectively offering it into the market at a zero price, the supplier will be paid (or pay, in the event of a negative LMP) the applicable LMP. In short, a generator who elected to "self-schedule" in the Midwest ISO would bear the economic consequences of doing so. In SPP, that supplier could avoid the consequences of uneconomic operation of a given unit, provided that it controlled sufficient Network Service or Firm Point-to-Point reservations against which it could self-schedule its units.

The ability to escape negative economic consequences provides an invitation, for those who find it in their interests to self-dispatch, to do so. The benefits of regional security-constrained economic dispatch increase with the percentage of participating generation. However, it is not necessarily the case that all firms benefit equally. It is possible that some firms may benefit by using self-dispatch of key units to degrade the efficiency of regional economic dispatch. In this context, "degradation" is a strategic behavior that reduces the efficiency of resource utilization, harming dependant firms more than opportunistic firms, and thereby giving the opportunistic firms a competitive advantage over their dependant rivals.[38] For example, a supplier with sufficient Network Service or Firm transmission reservation could self-schedule nearby generation to fully utilize key transmission facilities and thereby block competitors from the opportunity to sell to selected customers. Such strategic behavior could enable the supplier to capture those sales at the expense of reduced competition and higher consumer prices. Comparable behavior has been observed or alleged in the credit card industry, the provision of Internet backbone services, and in telecommunications.[39] Some utilities may find inefficient dispatch at specific times and locations to be in their economic interests because they profit by increasing costs to other users of the grid. In RTOs with full LMP pricing, this potential is checked in part by the fact that such utilities have to pay for the consequences of actions that lead to uneconomic use of the transmission grid. In an LMP market such as the Midwest RTO, the supplier who engaged in strategic blocking behavior would face sharply reduced or negative LMPs at its generator upstream from the constrained transmission facility. This check on opportunistic behavior is greatly reduced by the SPP market design.

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[38] See: A. Aviram, *Regulation by Networks*, John M. Olin Law & Economics Working Paper No. 181, 2nd Series, University of Chicago Law School (March 2003).
[39] *Ibid; See also:* S. Salop & Scheffman, *Raising Rivals' Costs,* 73 Amer. Econ. Rev. 267 (1983); J. Cremer, et al., *The Commercial Internet,* 48 J. Indus. Econ. 433 (2000).

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c. SPP EIS Dispatch: Reliability Impacts

Economic dispatch within SPP's proposed EIS market is not comparable to the security-constrained unit commitment and economic dispatch and related market based congestion management that occurs in other RTOs.

- There is no centralized security-constrained economic commitment of capacity in the SPP model. There is no mechanism that ensures operating and reserve capacity will be in appropriate locations to ensure reliability. Thus, the capacity available to be dispatched may not be optimal from an economic or reliability perspective.
- SPP is proposing an energy imbalance market and to dispatch imbalance energy. EIS dispatch comes into play only after there has been a schedule imbalance or, in the case of transmission congestion, after there has been a TLR event that results in the curtailment of EIS market flows.
- Our understanding is that when a transmission facility becomes congested, SPP will first TLR the flowgate and use the NERC IDC and SPP's new Curtailment Adjustment Tool to establish and allocate curtailment responsibilities to particular schedules and market flows. The NERC distribution calculator may be using different (and potentially no longer accurate) data, that would not be comparable to the real time network topology, power flow, state estimation, and contingency analysis information used as a basis for security-constrained economic dispatch by the Midwest ISO.
- Under the proposed EIS, resources that have offered into the EIS market would be redispatched to meet the EIS market portion of curtailment responsibilities. The contribution of self-scheduled units and other non-market flows to congestion would continue to be managed through inefficient TLR procedures.
- EIS economic dispatch will take into consideration only the specific transmission constraints that contributed to the TLR event and curtailment of EIS market flows. And, those constraints would contribute to redispatch only to the extent of the curtailments allocated to EIS market flows over the constrained flowgate. If an EIS redispatch caused a second line to overload, this apparently would not be considered in setting EIS dispatch signals until after another event has been declared on this second line and the EIS dispatch program is run again following this second event. This will create conflicts for control areas when protecting operating security limits for their transmission facilities could require ignoring SPP dispatch instructions and potentially incurring penalties. In some cases, multiple iterations thorough the EIS dispatch may be required to approach a "security-constrained" dispatch of market generation. And, in some cases, the interaction of multiple constraints might impede development of a stable, least cost solution.

Security-constrained economic dispatch in the Midwest ISO would recognize all operating security limits and achieve a genuinely security constrained dispatch in a single pass. While a potential improvement over current practices, the EIS market remains a reactive approach to reliability coordination. By contrast, full security-constrained unit commitment and economic dispatch is forward looking in that it makes maximum efficient use of the transmission system while anticipating and avoiding potential violations of operating security limits.

d. Longer Term Benefits of Participating in Transparent Energy Markets

The inclusion of a transmission system in a transparent regional market for energy and transmission capacity will alter incentives and behavior in a manner that is likely to produce significant benefits. It creates a liquid and transparent market that rewards suppliers for improving availability and holding down costs.

The incentives created by such a market lead participants to discover efficiency improvements that would have been difficult for any outside analyst to quantify or regulators to mandate. For example, given an efficient spot market, generation suppliers have a greater incentive to keep their units in operation when prices are higher and generation is more valuable. In PJM, this led to a significant reduction in forced outages – unplanned outages that could take a plant off line during peak price periods. Forced outage rates for fossil steam plants fell by 40 percent and for combustion turbines by 70 percent from 1994 – 2002. Such improvements have helped drive down the marginal cost of generation in PJM energy markets. And, consumers have benefited from lower production costs and wholesale prices.

Over a time, transparent power markets will influence the pattern and location of generation and transmission investments. Market influenced outcomes may be greatly superior to decisions based entirely on centralized planning. For example, the market would take into consideration differences in the locational value of capacity and the real option value of deferring the decision to invest under conditions of uncertainty. Such appropriate factors often are not considered when comparing the expected cost of alternative capacity expansion plans in the context of a regulatory proceeding.

The development of a transparent wholesale market enhances the options that are available to regulators as they seek an appropriate balance between cost of service regulation, incentive regulation, and reliance on markets. If a utility's transmission system is inside a wholesale energy market that is integrated with transmission operations, regulators can:

- Benchmark utility fuel and operating costs against location-specific spot prices;
- Take advantage of a larger and more liquid wholesale market should they decide to shift from ratepayers to investors some or all of the capital investment risks associated with the development of new generating capacity;
- Use location-specific prices to help identify where it may be cost-effective to build new generation or transmission capacity;
- Design variable pricing products for price responsive consumers that are based on efficient price signals that customers can trust to reflect the actual real-time or day-ahead marginal cost of power; and
- Foster the development of differentiated consumer energy products designed to better match consumer risk preferences.

These options leverage opportunities to generate very large efficiency gains in capital investment and performance that in the longer term are likely to be much more significant than the immediate benefits and costs addressed in our quantitative analysis.