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Witness: Ralph L. Luciani
Ellen Wolfe
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OF THE STATE OF MISSOURI

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PREPARED JOINT TESTIMONY OF
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VICE PRESIDENT, CRA INTERNATIONAL

AND

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SENIOR CONSULTANT, CRA INTERNATIONAL

ON BEHALF OF SOUTHWEST POWER POOL, INC.

Exhibit No. 5
Case No(s). EO-2006-0141 EO-2006-0142
Date 5-12-06 Rptr KF

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your names, positions, and business addresses.

A. Our names are Ellen Wolfe, Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746 and Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004. CRA's name was changed from Charles River Associates to CRA International on May 6, 2005.

Q. What is the purpose of your joint testimony?

A. We will summarize the methodology and findings in the Southwest Power Pool (SPP) Cost-Benefit Analysis study (Report) performed by CRA for the SPP Regional State Committee (RSC). The study was published on April 23, 2005 and presented by CRA to the RSC on April 25, 2005. The study was subsequently revised on July 27, 2005. The study was requested by the RSC to assess the impact of alternative future roles of SPP in light of its approval as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). In particular, we will describe the history and purpose of the study, discuss the study methodology and assumptions that were used, describe the study results with respect to specific costs and benefits, discuss other qualitative considerations evaluated in the study, and provide a comparison of the general framework of this study in comparison with other RTO cost-benefit studies.

Q. What are CRA's qualifications and experience in performing cost-benefit studies of RTOs?

A. CRA is comprised of over 500 professional staff. Our experts possess substantial electricity and gas industry knowledge and routinely provide clients with advice related to market economics, asset valuation, regulation, litigation, business strategy, public policy and market design. The CRA senior staff members that prepared this study have extensive experience in advising clients on institutional designs needed to effectively implement competitive electricity markets, and have performed a number of RTO cost-benefit studies. These include cost-benefit studies on behalf of RTO West in March 2002, on behalf of the Southeastern Association of Regulatory Utility Commission (SEARUC) in November 2002, on behalf of Dominion Power in June 2003, and on behalf of the Electric Reliability Council of Texas (ERCOT) in November 2004. In each of these studies, CRA has made use of its extensive knowledge of regional generation and transmission systems and electricity market structures and rules to specify a model representation of the regional electricity market. The computer simulation market model was used to project generation dispatch, production costs, inter-regional flows, and spot prices under various RTO-related scenarios. The results of the electricity modeling, supplemented with relevant RTO operating cost estimates, were then used to evaluate net benefits to individual regions and companies.

Q. Please describe your roles in the preparation of the study.

A. Ms. Wolfe was project manager of the study, and Mr. Luciani oversaw the financial evaluation of costs and benefits contained in the study. Both Ms. Wolfe and Mr. Luciani participated actively in the study from its inception in July 2004 through the writing of the report and presentation of the study to the RSC in April

2005. The CRA senior staff on this study also included Aleksandr Rudkevich, an expert on electricity market modeling, and J. Stephen Henderson, an expert on electricity policy and market power.

Q. Please describe your educational and professional backgrounds.

A. Ms. Wolfe has nearly 20 years of experience with electric utilities and in the energy industry, focusing on such issues as market designs and protocols, energy price forecasting and policy support. Ms. Wolfe previously led the RTO West and ERCOT cost-benefit studies. Ms. Wolfe has a B.S. in Electrical Engineering from the University of California, Davis, and Masters' degrees in Management and in Technology and Policy from the Massachusetts Institute of Technology.

Mr. Luciani has more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, and utility wholesale power solicitations. Mr. Luciani oversaw the financial and rate analyses presented in the SEARUC and Dominion Power RTO cost-benefit studies. Mr. Luciani has a B.S. in Electrical Engineering and Economics and a M.S. in Industrial Administration from Carnegie Mellon University.

2. HISTORY AND PURPOSE OF STUDY

Q. What was the purpose of the study?

A. The purpose of the study was to evaluate: (1) the costs and benefits that accrue from SPP-wide consolidated services and functions (which include reliability coordination and regional tariff administration) and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service (EIS) market.

Q. Describe the process used in preparing the study.

A. The study was performed under the direction of the RSC through the Cost Benefit Task Force ("CBTF"). The CBTF included representatives from the State Commissions in the SPP RSC, the SPP utilities, a consumer advocate, and SPP staff. After CRA's selection by the RSC in July 2004, an open, collaborative process was put in place by CRA and the CBTF in which stakeholders were presented multiple opportunities to review and comment on the proposed study methodology, input assumptions,[1] and interim results. Numerous conference calls and face-to-face meetings were held with CRA and CBTF members from July 2004 through April 2005. While stakeholders participated throughout the study process, the final study reflects the independent analyses, findings and judgment of CRA.

3. STUDY METHODOLOGY

Q. Please describe the general methodology applied in the study.

A. Five areas of analysis were selected and designed to provide a comprehensive understanding of the costs and benefits relevant to the SPP study questions.

a) Wholesale Energy Modeling

b) Allocation of Energy Market Impacts and Cost Impacts

c) Qualitative Assessment of Energy Imbalance Impacts

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[1] To perform the market modeling in the study, it was necessary to finalize or "freeze" the market model input assumptions as of August 2004.

d) Qualitative Assessment of Market Power Impacts

e) Aquila Sensitivity Cases

The Wholesale Energy Modeling addressed the expected impacts on the SPP energy market resulting from the different operational or system configuration assumptions in the various cases. This energy market simulation, using General Electric's Multi Area Production Simulation Software (MAPS) tool, included an assessment of the impact on production costs, on the dispatch of the system, and on the interregional flows in the study area. The Wholesale Energy Modeling provided the energy market impacts for the analysis of the Allocation of the Energy Market Impacts and Cost Impacts. The Allocation of Energy Market Impacts and Cost Impacts provided an assessment of the cost and energy market impacts on SPP and individual market participants. This assessment was based on specific assumptions regarding regulatory policies and the sharing of trade benefits and was used to provide detailed company- and state-specific impact measures. A qualitative review of relevant issues that were not quantified was also performed, along with a special sensitivity in which Aquila was assumed to join the SPP EIS market.

Q. What scenarios were modeled in the study?

A. CRA modeled three operational market scenarios in this study in order to compare several potential future operating states:

- **Base case:** SPP within its current footprint with no balancing market
- **EIS case:** A real-time EIS market is implemented within today's SPP tariff footprint

- **Stand-Alone case:** SPP tariff is abandoned and each transmission operator operates under its own transmission tariff

Q. What time period was evaluated in the study?

A. The time horizon for the study consisted of the calendar years 2006–2015. A 10-year period is often used for studies of this type in order to capture both near-term and longer-term impacts. For the MAPS modeling, detailed simulations were performed for 2006, 2010, and 2014, and interpolation and extrapolation were used to obtain results for the other years in the study horizon. The Aquila Sensitivity cases were evaluated only for the year 2006 and only the wholesale market impacts were assessed in the Report.

4. WHOLESALE ENERGY MODELING

Q. Please describe the general framework applied in the wholesale energy modeling.

A. For each simulation year, MAPS modeling was performed for each of the three scenarios, and the results were compared to produce the Wholesale Energy impacts. Thus, the impacts of SPP returning to a non-RTO structure were determined by comparing the Stand-Alone case with the Base case, and the impacts of the EIS market were determined by comparing the EIS case with the Base case. The quantitative modeling of the three scenarios was distinguished by three factors: through-and-out rates for transmission service, the dispatch of non-network generating units, and the transfer limits on constraints within SPP.

Section 3 of the Report describes the Wholesale Energy Modeling, and Section 3.1.2 specifically defines the simulation cases.

Q. Can you discuss further what the Base case is meant to represent?

A. The Base case was developed to be a representative simulation of the current SPP wheeling tariff structure, transmission allocation practices, and transmission path management approaches. In this sense, although not necessarily fully capturing all current bilateral arrangements and practices, it is designed to simulate the "status quo" SPP operations and practices.

Q. Please describe the differences between the Stand-Alone case and the Base case simulations.

A. The Stand-Alone case simulation models instituted wheeling out and wheeling through charges between control areas *within* SPP. In the existing structure, represented by the Base case, wheeling charges were not applied between SPP control areas.

Q. Please describe the differences between the EIS case and the Base case simulations.

A. There are two differences, both of which reflect inefficiencies in the existing Base case market structure which are expected to be alleviated in the EIS market. First, in the current market structure, the scheduling capacity of major transmission paths (flowgates) is reduced given that SPP does not have full dispatch control of resources needed to manage the flows of energy throughout SPP. In the EIS case, SPP will centrally dispatch units and there is expected to be sufficient control and visibility to fully schedule the flowgates. The flowgate capacity is 10% lower in the Base case than in the EIS case based on historical flowgate flows during congestion events.

The second difference is the optimality of the dispatch of the system. Under the current market structure (Base case), some generating units, primarily certain merchants units in SPP, do not have network service and only obtain transmission service when there is available capacity. Under the EIS market, all units will have access to provide energy in the EIS market. In the Base case, the non-network units were only dispatched if there was spare transmission capacity. The list of non-network units treated in these cases was developed under consultation with the CBTF.

Q. What were the key inputs used in the wholesale energy modeling?

A. There are a large number of input variables to the wholesale energy models, and these assumptions were developed in conjunction with, or reviewed by the CBTF and SPP staff. The assumptions are described in detail in the Report Appendices 3-1 and 3-2. Key assumptions include the following:

- Hourly loads based on FERC 714 filings for 2002
- Gas and oil price forecasts developed by CRA
- Generation bids based on marginal cost[2] (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits based on a number of public and private sources of information, as described in the Report Appendix 3-1) and an efficient dispatch based on these bids[3]

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[2] Generating costs used in the simulated dispatch did not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

[3] In general, the simulation models performed the economic dispatch of generating units as if all energy transactions occurred with a regional spot market. Individual bilateral transactions were not modeled

- Coal forecast as obtained from Resource Data International
- Use of a large "footprint" for the modeling, compiled by CRA, encompassing much of the Eastern Interconnect
- A transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by SPP
- Environmental adders based on forecast emissions values (based upon EPA's Clean Air Markets database for 2002)
- New generation additions already under construction based on public information and validated with the CBTF.

5. COST AND BENEFIT MEASURES

Q. What measures of costs and benefits were used in the study?

A. Welfare for regulated customers of a utility, as measured in this study, was measured based on the charges to local area load for generation and transmission service, assuming that any benefits to the regulated utility are passed through to its native load. If these charges decrease, regulated customer welfare is assumed to increase. To quantify the change from Base case conditions to Stand-Alone status or participation in an EIS market, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation or production costs, energy purchases, wheeling charges, and O&M expenditures. The major categories of benefits and costs addressed in this study were trade benefits, wheeling charges and revenues,

explicitly, but rather were assumed to be efficient – given the simulation model parameters – such that the resulting dispatch would be equivalent to one that explicitly reflected bilateral transactions.

SPP implementation and operating costs, and individual utility implementation and operating costs.

Q. What were the sources of these cost and benefit measures?

A. Trade benefits and wheeling impacts were computed using the Wholesale Energy modeling results for each case. The changes in SPP costs from the Base to the Stand-Alone case and from the Base to the EIS case were estimated using projected SPP budgets. Individual company changes in operating and capital costs that would take place under stand-alone status and under participation in the EIS market were projected by each company, reviewed by CRA for consistency in approach, and converted to revenue requirements.

Q. Can you describe in further detail what trade benefits are and how they relate to the Wholesale Energy modeling results?

A. As described in Section 4, the cases analyzed in this study (Base, Stand-Alone, and EIS) reflect varying degrees of impediments to trade between regions. In particular, the institution of intra-SPP wheeling rates in the Stand-Alone case results in greater impediments to trade between utility areas, and institution of the EIS market results in reduced impediments to trade between utility areas. Reductions in the impediments to trading between utilities should generally result in a more efficient system dispatch and production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they are comprised of fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. While production cost changes cannot be used directly to allocate trade benefits to individual utility areas, the sum of all individual utility trade benefits will equal the total change in production cost.

6. STUDY RESULTS

Q. Please characterize the study results and how they should be interpreted.

A. The results reflect a number of inter-related analyses. As a result, individual elements of any particular analysis cannot be selectively changed without impacting the findings of the other analyses. The study results reflect our best prediction of future impacts, but are dependent on forecasts of uncertain input assumptions that may not unfold exactly as predicted. As will be discussed, the study results are subject to a margin of error, and the accuracy of the study results is higher at the regional level than it is for individual companies and states.

Q. Given the large number of inputs and the uncertainty in them, what provides any level of assurance that the results are meaningful?

A. There are a wide variety of assumptions used in the study, especially related to the wholesale energy modeling. However, because the wholesale energy impacts are measured as the difference between two cases, in many cases uncertainties in assumptions tend to operate similarly between cases and therefore tend to cancel out between cases. The majority of assumption uncertainties tend to operate in this fashion. It is only those few assumptions that tend to be sensitive to the market structure that likely could significantly influence the measured impacts. Assumptions such as these, to which the results may be sensitive, are discussed more specifically in the study.

6.1. Cost-benefit Results for EIS Market

Q. Please describe the cost-benefit results for the implementation of the EIS market.

A. The study found that the implementation of an EIS market within SPP would provide aggregate trade benefits of $614 million over the 10-year study period[4] to the transmission owners under the SPP tariff,[5] as summarized in Table 1. This

[4] All study period figures in this study are discounted present values as of January 1, 2006 over the 2006-2015 period. An annual discount rate of 10% was applied. Annual inflation was assumed to be 2.3% over the study period.

[5] Transmission owners under the SPP tariff include six investor-owned utilities (American Electric Power, Empire Electric Company, Kansas City Power & Light, Oklahoma Gas & Electric, Southwestern Public Service, and Westar Energy), two cooperatives (Midwest Energy and Western Farmers), one federal agency (Southwestern Power Administration), one state agency (Grand River Dam Authority) and one

represents about 2.5% of the total production costs within the SPP area during this period. The study accounted for impacts due to changes in wheeling charges and wheeling revenues, which was a minor consideration as shown in Table 1.

The study also evaluated the administrative costs of implementing the EIS market, both in terms of the costs incurred by SPP to administer the EIS market and of the costs to the utilities of participating in such a market. SPP's 10-year costs are shown in Table 1 as being $105 million, while the 10-year costs of the EIS market participants are estimated to be $108 million (increased costs are reported in the table as negative benefits so that all of the numbers in the table can be added directly). On net, the EIS market is estimated to provide considerably more benefits than costs, with the net benefits being $373 million to the transmission owners under the SPP tariff over the 10-year study period. In addition, the study estimated that benefits to other typical load-serving entities in the EIS market would be an additional $45.2 million without consideration of individual implementation costs.[6]

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municipality (Springfield, Missouri). The Southwestern Power Administration has recently withdrawn from the SPP, but continues to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.

[6] These other entities are Arkansas Electric Cooperative Corporation; Oklahoma Municipal Power Authority; the Board of Public Utilities, Kansas City, Kansas; and City Power and Light, Independence, Missouri. Together with the transmission owners under the SPP tariff, these entities account for nearly all non-merchant generation in the EIS market. Other SPP members not modeled as participating in the EIS market in these results include Aquila, Cleco Power, Sunflower Electric, City of Lafayette, Louisiana, and Louisiana Energy & Power Authority.

Table 1 EIS Case, Benefits (Costs) by Category for Transmission Owners Under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

Q. How do the trade benefits of $614.3 million compare to the total production costs savings in the MAPS modeling?

A. The total production cost savings across the modeled footprint (most of the Eastern Interconnect) over the study period in the EIS case was $1,173 million. Thus, transmission owners under the SPP tariff obtain 52% of the total trade benefits. Including other SPP members that are not transmission owners but part of the EIS market, as well as SPP merchants and other SPP members bordering the EIS market, yields $813 million in trade benefits to SPP members, or roughly 70% of total production cost savings. Neighboring control areas that trade with SPP members obtain the remainder of the trade benefits.

Q. What were the estimated impacts of the EIS market on individual SPP utilities?

A. Table 2 shows the distribution among the individual utilities within SPP of these SPP-wide net benefits. As described in Section 4.1 of the Report, trade benefits were allocated among utilities within SPP, and control areas with direct interties to SPP, based on the change in utility generation in the EIS market case relative to the Base case. Individual utility wheeling impacts were assessed based on the change in the hourly MAPS net physical flows between utility control areas in the EIS market case relative to the Base case. The EIS market implementation costs incurred by SPP were allocated to individual companies using the standard company SPP assessment percentages applied in SPP budgets. The EIS market implementation costs incurred internally by each utility were estimated on a company-specific basis as described in Appendix 4-4 of the Report.

As shown in Table 2, most of the utilities are shown as receiving positive net benefits over the 10-year study period. Four of the utilities (KCPL, Midwest Energy, SWPA, and GRDA) have small impacts, either positive or negative, that should be interpreted as essentially breaking even. The results for these utilities are probably smaller than the margin of error of this study. Those utilities with larger positive impacts tend to be the companies that are measured in the EIS case to have a relatively significant change in the dispatch of their generating units under the institution of an EIS market.

Table 2 EIS Case, Benefits (Costs) for Individual Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	47.9
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	27.4
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

Q. Have you performed any updates to the allocation analysis since the time that the Report was originally published in April?

A. Yes. We discovered that the ownership shares for some jointly-owned generating units in SPP had been incorrectly input in the allocation model. Most were large coal-fired baseload plants that operate similarly in all scenarios and correcting the ownership shares would have only a minor impact on the individual company results. However, one of these jointly owned units, Stateline Combined Cycle, is a 500 MW gas-fired combined-cycle unit and has a significant change in its dispatch between the Base and EIS cases. The unit had been treated as 100% owned by Empire in the allocation model, and correcting the ownership shares to 60% for Empire and 40% for Westar Energy provides a material difference in the EIS market benefits allocable to Empire and Westar Energy. We corrected for the Stateline Combined Cycle ownership in the revised Report issued on July 27, 2005. The correction decreases the benefits for Empire and increases the benefits for Westar Energy from those originally presented in the Report in April. Table 2 above incorporates the figures from the revised Report.

Q. What is the margin of error in these results?

A. The study results are subject to a margin of error due to various abstractions that must be made in any modeling exercise such as this. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, and error in forecasting RTO costs. CRA has not had the opportunity to develop a formal margin of error for this study, but CRA experience in modeling exercises of this type suggest that changes of less than $10 million over the study period for individual companies are likely to be within the study's margin of error.

Q. Can you discuss further the negative impacts shown for GRDA, KCPL and Midwest Energy?

A. Yes. Each of these companies shows trade benefits that exceed EIS implementation costs, but the resulting net benefits are offset by the wheeling impacts. While the net wheeling impacts on SPP as a whole are relatively small in the EIS case, the relative impact on certain individual companies is more significant. In the study, wheeling impacts were calculated based on hourly MAPS *net physical* flows between control areas, and as a practical matter this method cannot precisely represent the specific transactions that would actually pay wheeling charges, particularly in a highly interconnected compact region such as SPP. Further, some aspects that impact wheeling charges such as loop flow, "through" transactions that sink in adjoining SPP control areas, wheeling rate

Q. Can you comment generally on the level of accuracy in the regional results in comparison to the results at the company and state level?

A. Yes, as a general matter, any particular source of error in modeling (e.g., incomplete data on a particular unit or a particular transmission constraint) will have a greater relative impact on a localized area than on a broader region. Some sources of uncertainty in the study, such as the use of physical flows to estimate scheduled wheeling transactions, tend to offset one another when looking across a broader region. Similarly, the method used to allocate trade benefits to individual companies uses a level of aggregation that may not precisely capture the localized benefits of trading relative to the benefits of trading in other areas. Moreover, some uncertainties, such as the precise allocation of SPP wheeling-out revenues to individual companies, do not affect regional measures, but do provide additional uncertainty to company and state results.

6.2. Stand-Alone Cost-Benefit Results

Q. Please describe the cost-benefit results for the Stand-Alone case.

A. In the Stand-Alone case, implementation of intra-SPP wheeling rates leads to a less efficient dispatch and thereby increases system-wide production costs relative to the Base case. Table 4 shows that the trade benefits allocated to the transmission owners under the SPP tariff area is negative $21 million over the 10-year study period for this movement to a stand-alone structure. This is about 0.1% of the SPP production costs over this period. Wheeling rate impacts are shown in Table 4 as being somewhat positive, with a net impact of $16 million. The major costs associated with this case are the administrative costs that must be undertaken by the individual utilities if SPP were to no longer administer the SPP Tariff. In addition, the SPP withdrawal obligations are shown as an additional cost of $47 million.

These additional costs are offset to some degree by the reduction in FERC fees that would occur under a Stand-Alone scenario, assuming that FERC continues to assess its fees as it does at present. CRA has no way to assess whether such a revision in FERC's assessment formula is likely, but this benefit is subject to considerable regulatory uncertainty. So, while Table 4 indicates that the Stand-Alone case would result in about $70 million of additional net costs over the 10-year study period, this estimate could easily be closer to $100 million in net costs if FERC were to revise the formula for its fees.

Table 4 Stand-Alone Case, Benefits (Costs) by Category for Transmission Owners Under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Q. What were the estimated impacts of the Stand-alone case on individual SPP utilities?

A. Table 5 shows the distribution among the individual utilities within SPP of these SPP-wide net costs (negative net benefits). For the reasons discussed above, the results in Table 5 are shown without the impact of wheeling revenues and charges. As shown, excluding these wheeling impacts, the benefits of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).[8]

Table 5 Stand-Alone Case, Benefits (Costs) for Individual Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling
AEP	IOU	(19.8)
Empire	IOU	(5.8)
KCPL	IOU	(17.8)
OGE	IOU	(8.2)
SPS	IOU	(5.0)
Westar Energy	IOU	(17.0)
Midwest Energy	Coop	(7.9)
Western Farmers	Coop	1.3
SWPA	Fed	1.2
GRDA	State	(4.8)
Springfield, MO	Muni	(2.5)
Total		(86.3)

In performing the distribution to individual utilities shown in Table 5, trade benefits were allocated using the same method described above for the EIS market case. The incremental costs incurred by individual utilities to provide the functions currently provided by SPP were estimated on a company-specific basis as described in Appendix 4-3 of the Report. FERC charge impacts and

[8] The individual company Stand-Alone results with wheeling impacts are provided in the study, but, as noted in the study, should be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts.

withdrawal obligations also were estimated on a company-specific basis as described in Section 4.2 of the Report.

Q. What were the estimated impacts of the Stand-alone case on individual states?

A. The estimated impact of the Stand-alone case on the retail customers of the six investor-owned utilities (IOUs) in Table 5 is distributed to individual states in Table 6. This state-by-state allocation of benefits is based on a load-ratio share methodology, and, as shown, the impact on most of the states is relatively modest.

Table 6 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

	Benefits excl. Wheeling
Arkansas	(3.0)
Louisiana	(2.6)
Kansas	(22.2)
Missouri	(13.7)
New Mexico	(0.7)
Oklahoma	(16.2)
Texas	(5.5)

Q. What were the estimated impacts of the Stand-Alone case on individual Missouri investor-owned utilities?

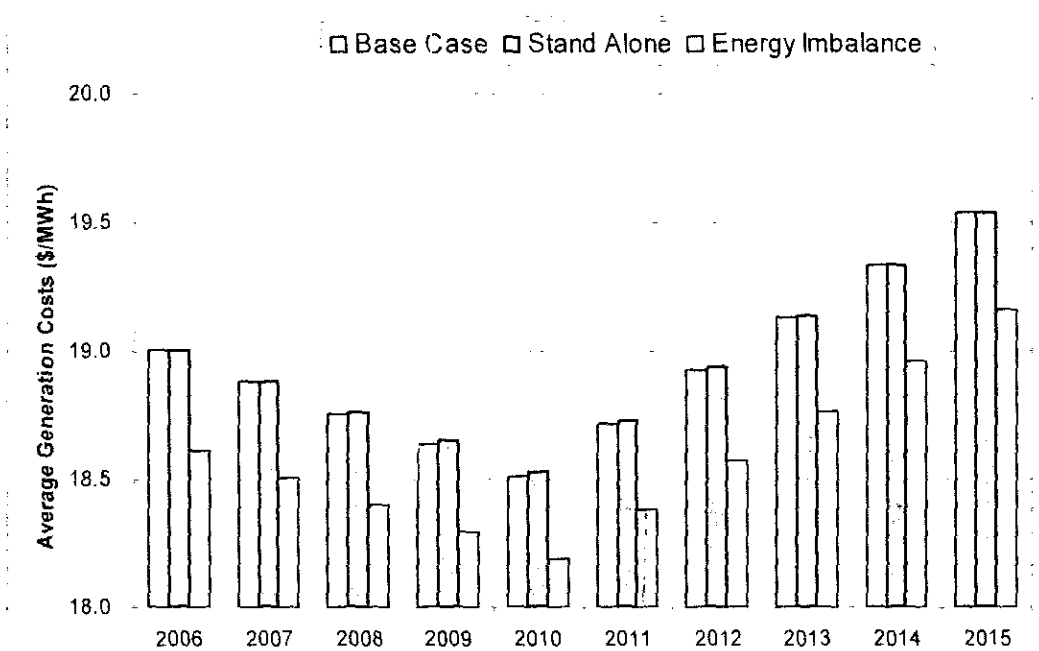
A. The Missouri retail customer impacts shown in Table 6 are comprised of increased costs of $4.8 million for Empire and $8.9 million for KCPL.

6.3 Wholesale Impacts to SPP

Q. Please describe the wholesale energy market impacts evaluated in the study.

A. The Wholesale Energy Modeling process provided the energy-impact inputs to the allocated results discussed above. It also yields some high-level, region-wide wholesale market metrics related to the three cases simulated. Figure 1 shows the SPP average annual generation cost impacts resulting from the cases. (Note that the trend across the years is primarily due to non-case related factors such as fuel prices, transmission system upgrades, and load growth.) The difference between the respective average cost in each year reflects the fact that the institution of the EIS market increases dispatch efficiency (reduces generation, or production, cost[9]) by approximately 2% ($0.32 to $0.39 per MWh).

Figure 1 Wholesale Aggregate Generation Cost Impacts



SPP spot energy prices are also expected to decrease by approximately 7%. The Stand-Alone comparison with the Base case did not reveal significant differences.

[9] Generation costs, or production costs include start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

These results are consistent with the level of SPP-wide trade benefits discussed above in the individual case findings.

6.4 Qualitative Analysis of EIS Impacts

Q. Please describe the qualitative considerations evaluated in the study.

A. In addition to the quantified impacts discussed above, the long-run impacts of implementing a formal nodal EIS market are expected to include improved transparency and improved price signals. Added complexities may produce adverse impacts during a transition period of roughly three to five years. Applying explicit imbalance energy prices creates risks for market participants associated with not following schedules; however, these risks are likely to abate as participants become familiar with the EIS market and are offset by the improved efficiency in scheduling that will result from the EIS market price signals. The movement with the EIS to the centralized management of inadvertent energy will likely be subject to additional production efficiencies, a benefit that is not captured in the quantitative results of the energy modeling. That is, with SPP operating the real-time balancing service, SPP will have greater visibility into the region than individual control area operators have now or would have going forward absent a regional Energy-Imbalance Service. SPP will also likely have improved schedule information and can better anticipate what otherwise would have been loop flows between adjacent control areas.

6.5 Market Power Considerations

Q. Please describe the market power considerations evaluated in the study.

A. CRA did not conduct a formal study of market power in conjunction with this cost-benefit study. Two primary factors, of approximately equal strength, suggest that market power is not likely to become a significant consideration under the EIS market, in particular. These are (1) the provision for an ongoing market monitoring function within SPP and for a separate, independent monitor, and (2) the lack of incentive for the exercise of market power under the economic conditions likely to prevail under the EIS market. Market monitoring is required by FERC and should provide a substantial check on any potential to exercise market power after the implementation of the EIS market. The continuation of cost-based regulation for most of the output of generation in this region means that the EIS market is not likely to augment the incentive to exercise market power in a significant way.

6.6 Aquila Sensitivity Case Results

Q. Please describe the wholesale market results of the Aquila in SPP sensitivity.

A. Using the Wholesale Energy Modeling sensitivity analysis performed for Aquila for 2006, CRA considered both (1) the wholesale market effects of whether Aquila was part of the MISO or whether Aquila was part of SPP, and (2) the sensitivity of the EIS wholesale market results to which RTO that Aquila joins. That Aquila wholesale market sensitivity simulation showed that if Aquila were to affiliate with SPP there would be wholesale market benefits to Aquila, though impacts to the surrounding SPP region was not necessarily affected in the same direction. That analysis suggested that while the SPP region's generating costs would be lower with Aquila in MISO, Aquila's generating costs would be lower with Aquila in SPP. The sensitivity analysis indicated that the wholesale market measures for the EIS market are not particularly sensitive to whether Aquila is in MISO or in SPP.

7. COMPARISON TO OTHER COST BENEFIT STUDIES

Q. How does the SPP Cost Benefit study compare to other RTO cost-benefit studies that have been performed?

A. Appendix 2-1 of the Report describes a number of RTO cost-benefit studies that have been performed since 2001, several of which were performed by CRA senior staff members. As the Report notes, each of these RTO cost-benefit studies differs in a number of important respects, addressing different policy questions and comparing market restructuring at various stages of integration. Of the studies, one – a study addressing the historical benefits of PJM – was based on historical evidence. The other studies included simulations and most used the same MAPS modeling application that was employed in the SPP study.

The studies have primarily addressed the benefits of RTO formation, although one of the studies, performed in 2004 for ERCOT addressed a nodal versus a zonal market structure, with the RTO in operation in both cases. Like the SPP study, the SEARUC study prepared by CRA also performed an allocation of trade benefits to determine impacts to native load, but performed the allocation to larger regions than the control areas used in the SPP study. Table 1 of the Report Appendix 2-1 provides a detailed comparison of study characteristics.

Q. Can you describe further how the SPP Cost Benefit study compares to the SEARUC cost-benefit study performed by CRA?

A. Yes, the SEARUC study focused in part on an assessment of the timing and regulatory treatment of the transmission integration costs needed to fully integrate the significant amount of merchant generating capacity that had been constructed in the Entergy and Southern Company regions. The SPP region is not faced with transmission integration cost issues of a similar magnitude, and thus this issue was not a focus of the SPP study.

Absent this transmission integration issue, the SEARUC study found 10-year benefits for the institution of a SeTrans RTO with a locational marginal pricing market of $352 million. However, the benefits to the GridSouth and GridFlorida RTOs were found to be negative. In considering these results, it is important to understand that the SEARUC study analyzed a transition from a "No RTO" base case in which local load-serving utilities were essentially in a stand-alone status, and not participating in the regional joint functions already in place at SPP (e.g., tariff administration, reliability coordination, available transmission capacity calculations). Thus, the incremental costs to move to an EIS market relative to the Base case for SPP were substantially less than those estimated for the SEARUC RTOs to start-up, implement and operate an RTO from base stand-alone conditions.

For example, the 10-year RTO implementation and operation costs projected in the SEARUC study ranged from $543 to $693 million for the SeTrans RTO and from $501 to $632 million each for GridSouth and Grid Florida. This compares to the projected $212 million in 10-year EIS implementation and operation costs for SPP (including both SPP and member utility costs). On a $/MWh of load basis, the SPP EIS costs were roughly equal to the SeTrans RTO costs, but about half that of GridSouth and GridFlorida (which are more comparable in terms of load served to the SPP EIS market).

8. CONCLUSIONS

Q. Please summarize your conclusions.

A. The study found that the implementation of an EIS market within SPP would provide nearly $400 million in benefits to the Transmission Owners under the SPP tariff. The benefits to other EIS market members and to regions bordering the SPP EIS market are also significant. While there are substantial costs that will be incurred by SPP and by EIS participants in implementing and administering the EIS market, the projected regional benefits significantly exceed these projected costs. With respect to Missouri, the collective benefit of the EIS market to the Missouri retail ratepayers of Empire and KCPL are substantially positive.

Q. Does this conclude your joint testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	))))	Case No. EO-2006-0141

AFFIDAVIT OF ELLEN WOLFE

State of CALIFORNIA)
) ss
County of PLACER)

Ellen Wolfe, being first duly sworn on his oath, states

1. My name is Ellen Wolfe. I am Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, prepared as joint testimony with Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004, on behalf of Southwest Power Pool, Inc., consisting of twenty-nine (29) pages, having been prepared in written form for introduction into evidence in the above-captioned case.

3. In consultation with Ralph L. Luciani, I have knowledge of the matters set forth therein. I hereby swear and affirm that the answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Ellen Wolfe
Ellen Wolfe

Subscribed and sworn before me this 29th *day of September 2005.*

EILEENE M. SCHLICHTING
COMM. # 1540381
NOTARY PUBLIC-CALIFORNIA
PLACER COUNTY
COMM. EXP. JAN. 1, 2009

Eileene M. Schlichting
Notary Public

My commission expires Jan. 1, 2009

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	))))	Case No. EO-2006- 041

AFFIDAVIT OF RALPH L. LUCIANI

State of ____________)
) ss
County of ____________)

Ralph L. Luciani, being first duly sworn on his oath, states:

1. My name is Ralph L. Luciani, Vice President, CRA International, 1201 F Street, NW, Suite 700, Washington, DC 20004.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, prepared as joint testimony with Ellen Wolfe, Senior Consultant, CRA International (CRA), 5925 Granite Lake Drive, Suite 120, Granite Bay, CA 95746, on behalf of Southwest Power Pool, Inc., consisting of twenty-nine (29) pages, having been prepared in written form for introduction into evidence in the above-captioned case.

3. In consultation with Ellen Wolfe, I have knowledge of the matters set forth therein. I hereby swear and affirm that the answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Ralph L. Luciani

Ralph L. Luciani

Subscribed and sworn before me this 28th day of September 2005.

Notary Public

My commission expires: 1/1/2006

Karyn Joelle Walz
Notary Public, District of Columbia
My Commission Expires 1-1-2008

Southwest Power Pool

Cost-Benefit Analysis

Performed for the SPP Regional State Committee

Final Report
April 23, 2005
(revised July 27, 2005)

CHARLES RIVER ASSOCIATES

Schedule 1

CRA CHARLES RIVER ASSOCIATES

Charles River Associates

Ellen Wolfe
Aleksandr Rudkevich
Stephen Henderson
Ralph Luciani
Ezra Hausman
Kaan Egilmez
Prashant Murti
Poonsaeng Visudhiphan

CRA CHARLES RIVER ASSOCIATES

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Revisions

This Report was revised on July 27, 2005 to correct for the ownership shares of the Stateline Combined Cycle unit owned by Empire and Westar Energy. The revision affects the net benefits allocated to Empire and Westar Energy. Revised pages are noted, and include pages X and XI of the Executive Summary, pages 4-11 and 4-12, and pages AII-13 through AII-17 in Appendix 4-2.

List of Abbreviations

AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
ATC	Available Transfer Capability
CAO	Control Area Operator
CBA	Cost-Benefit analysis
CBTF	SPP-RSC Cost-Benefit Task Force
CC	Combined Cycle
CRA	Charles River Associates
CT	Combustion Turbine
EC	Electric Cooperative
EIS	Energy Imbalance Service
FERC	Federal Energy Regulatory Commission
GRDA	Grand River Dam Authority
INDN	City Power & Light, Independence
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
IT	Information Technology
KACY	The Board of Public Utilities, Kansas, City
KCPL	Kansas City Power & Light
LIP	Locational Imbalance Pricing
LMP	Locational Marginal Price; Locational Marginal Pricing
MAPS	Multi-Area Production Simulation
MIPU	Missouri Public Service and St. Joseph Light & Power
MISO	Midwest ISO
MW	Megawatt
MWh	Megawatt-Hour
OATTs	Open Access Transmission Tariffs
OGE	Oklahoma Gas & Electric
O&M	Operation and Maintenance
OMPA	Oklahoma Municipal Power Authority
RSC	Regional State Committee
RDI	Resource Data International
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SPC	SPP Strategic Planning Committee
SPP	Southwest Power Pool
SPS	Southwest Public Service
SWPA	Southwestern Power Administration
TLR	Transmission Line Relief
TTC	Total Transfer Capability
VOM	Variable Operation and Maintenance
WEPL	WestPlains Energy

Executive Summary

Background

Charles River Associates (CRA) has conducted a cost-benefit analysis for the members[1] of the Southwest Power Pool (SPP) under contract with the SPP Regional State Committee (RSC)[2]. The study was requested to assess the impact of alternative future roles of SPP in light of its approval as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC). The study involved (1) an analysis of the probable costs and benefits that would accrue from consolidated services and functions (which include reliability coordination and regional tariff administration) and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service (EIS) market.

The RSC established a Cost Benefit Task Force (CBTF) composed of staff members from the member state commissions, SPP member utilities, one consumer advocate, and SPP staff members to initiate and coordinate this project. The RSC through the CBTF requested that CRA assess the costs and benefits of two alternative cases, in particular. The impact of SPP implementing an EIS market is evaluated in the EIS case, while the impact of individual transmission owners providing transmission service under their own Open Access Transmission Tariffs (OATTs or Tariffs) is evaluated in the Stand-Alone case. The EIS case is intended to represent an incremental step in the direction of Locational Marginal Pricing (LMP), while the Stand-Alone case is intended to represent a return to the traditional approach of individual control areas entering into bilateral trading arrangements and control of transmission congestion through NERC Transmission Line Relief (TLR) procedures.

Methodology

CRA approached the study of these two scenarios through five areas of analysis:

a) Wholesale Energy Modeling
b) Allocation of Energy Market Impacts and Cost Impacts
c) Qualitative Assessment of Energy Imbalance Impacts
d) Qualitative Assessment of Market Power Impacts
e) Aquila Sensitivity Cases

The time horizon for the study consisted of the calendar years 2006–2015. Detailed simulations were performed for 2006, 2010, and 2014, and interpolation and extrapolation were used to obtain results for the other years in the study horizon. The Aquila Sensitivity cases were evaluated for the model year 2006 only.

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[1] The Southwestern Power Administration has formally withdrawn from the SPP, but will continue to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.

[2] The SPP RSC is a voluntary organization that may consist of one designated commissioner from each state regulatory commission with jurisdiction over one or more SPP members.

The **Wholesale Energy Modeling** addressed the expected impacts on the SPP energy market resulting from the different operational or system configuration assumptions in the various cases. This energy market simulation, using General Electric's MAPS tool, included an assessment of the impact on production costs, on the dispatch of the system, and on the interregional flows in the study area.

The system production costs associated with each market design alternative were the primary measure used for the quantitative evaluation of the scenarios. The energy modeling results also served as inputs to the allocation processes for further evaluation of impacts.

CRA modeled three operational market scenarios in this study:

- **Base case:** SPP within its current footprint with no balancing market
- **EIS case:** A real-time Energy Imbalance Service market is implemented within today's SPP tariff footprint
- **Stand-Alone case:** SPP tariff is abandoned and each transmission operator operates under its own transmission tariff

The quantitative modeling of these three scenarios was distinguished by three factors: through-and-out rates for transmission service, the dispatch of non-network generating units, and the transfer limits on constraints within SPP. Through-and-out rates are currently not used within the SPP footprint and so are not in place in either the Base case or the EIS case. These internal SPP transmission rates are implemented only in the Stand-Alone case. The non-network generating units, primarily certain merchants units in SPP, are considered to be restricted in their dispatch in the Base and Stand-Alone cases due to a higher priority dispatch accorded to network resources on behalf of native load. In the Base case, transfer limits were set below the physical capacity of the associated lines to reflect suboptimal congestion management through the TLR process, consistent with observed historical utilization. Both the restriction of the non-network resources and the suboptimal transfer capacities are eliminated in the EIS case, thereby enabling the merchant plants to participate fully in the EIS market and resulting in more efficient congestion management.

The **Allocation of Energy Market Impacts and Cost Impacts** is the portion of the cost-benefit study that provides an assessment of the cost and energy market impacts on individual market participants. This assessment was based on specific assumptions regarding regulatory policies and the sharing of trade benefits and was used to provide detailed company- and state-specific impact measures. The major categories of benefits and costs were trade benefits, wheeling charges and revenues, SPP implementation and operating costs, and individual utility implementation and operating costs.

The **Qualitative Assessment of Energy Imbalance Impacts** addresses impacts of Energy Imbalance Service other than those quantified in the modeling. As part of this qualitative analysis, CRA consultants compared a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against a variety of metrics such as volatility, risk, and competition.

The **Qualitative Assessment of Market Power Impacts** addresses the likelihood that the implementation of an EIS in SPP would increase the potential for the exercise of market power in the SPP region, especially in the context of the market monitoring function and the continuation of cost-based regulation in this region.

The **Aquila Sensitivity Cases** portion of the study addresses the impact if Aquila were considered to be part of SPP rather than part of the MISO RTO, which was the assumption for the balance of the study. In this case the reserve requirements for individual SPP companies are reduced as reserve sharing is implemented over a larger set of participants (including the Aquila regions). The SPP regional wholesale energy modeling results were determined, as were wholesale impacts on Aquila. The Aquila sensitivity study was performed for the Base case and for the EIS case.

Findings

EIS Case

The study found that the implementation of an EIS market within SPP would provide optimal aggregate trade benefits of $614 million over the 10-year study period[3] to the transmission owners under the SPP tariff,[4] as summarized in Table 1. These trade benefits are the allocated portion of the overall production cost savings that occur within the entire modeling footprint (most of the Eastern Interconnection), as determined by the MAPS simulation study. This represents about 2.5% of the total production costs (production costs include fuel, variable O&M, start-up, and emissions costs) within the SPP area during this period. The study accounted for impacts due to changes in wheeling charges and wheeling revenues, which was a minor consideration as shown in Table 1.

The study also evaluated the administrative costs of implementing the EIS market, both in terms of the costs incurred by SPP to administer the EIS market and of the costs to the utilities of participating in such a market. SPP's 10-year costs are shown in Table 1 as being $105 million, while the 10-year costs of the EIS market participants are estimated to be $108 million. On net, the EIS market is estimated to provide considerably more benefits than costs, with the net benefits being $373 million to the transmission owners under the SPP tariff over the 10-year study period. In addition, the study estimated that benefits to other typical load-serving entities in the EIS market would be an additional $45.2 million without consideration of individual implementation costs.[5]

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[3] All study period figures in this study are discounted present values as of January 1, 2006 over the 2006-2015 period. An annual discount rate of 10% was applied. Annual inflation was assumed to be 2.3% over the study period.

[4] Transmission owners under the SPP tariff include six investor-owned utilities (American Electric Power, Empire Electric Company, Kansas City Power & Light, Oklahoma Gas & Electric, Southwestern Public Service, and Westar Energy), two cooperatives (Midwest Energy and Western Farmers), one federal agency (Southwestern Power Administration), one state agency (Grand River Dam Authority) and one municipality (Springfield, Missouri). The Southwestern Power Administration has recently indicated that it will formally withdraw from the SPP, but continue to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.

[5] These other entities are Arkansas Electric Cooperative Corporation; Oklahoma Municipal Power Authority; the Board of Public Utilities, Kansas City, Kansas; and City Power and Light, Independence, Missouri. Together with the transmission owners under the SPP tariff, these entities account for nearly all non-merchant generation in the EIS market. Other SPP members not modeled as participating in the EIS market in these results include Aquila, Cleco Power, Sunflower Electric, City of Lafayette, Louisiana, and Louisiana Energy & Power Authority. The introduction of the EIS market affects these utilities as well, and the impacts are reported in the body of this study.

Table 1 EIS Case, Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

Table 2 shows how these SPP-wide net benefits are estimated to be distributed among the individual utilities within SPP. Most of the utilities are shown as having positive net benefits over the 10-year study period. Four of the utilities (KCPL, Midwest Energy, SWPA, and GRDA) have small impacts, either positive or negative, that should be interpreted as essentially breaking even. The results for these utilities are probably smaller than the margin of error of this study.[6] Those utilities with larger positive impacts tend to have a relatively significant impact on the dispatch of their generating units under the institution of an EIS market.

[6] The study results are subject to a margin of error due to various abstractions that must be made in any modeling exercise such as this. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, and error in forecasting RTO costs. CRA has not had the opportunity to develop a formal margin of error for this study, but CRA experience in modeling exercises of this type suggest that changes of less than $10 million over the study period for individual companies are likely to be within the study's margin of error.

Table 2 EIS Case, Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	47.9
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	27.4
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

Table 3 shows how the results for the retail customers of the six investor-owned utilities (IOUs) in Table 2 are estimated to be distributed among the states in the region. This state-by-state allocation of benefits is based on a load-ratio share methodology[7] and shows that the IOU retail customers in all states but Louisiana would most likely experience positive benefits, although the positive results for Arkansas and New Mexico are relatively modest.[8]

Table 3 EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Arkansas	8.5
Louisiana	(3.8)
Kansas	26.4
Missouri	41.7
New Mexico	9.2
Oklahoma	141.1
Texas	26.6

[7] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma and Southwestern Electric Power Company, before allocation to individual states.

[8] To the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

Stand-Alone Case

In the Stand-Alone case, implementation of intra-SPP wheeling rates leads to a less efficient dispatch and thereby increases system-wide production costs in comparison with the Base case. Table 4 shows that the trade benefits allocated to the transmission owners under the SPP tariff area is negative $21 million over the 10-year study period. This is about 0.1% of the production costs in this area over this period. By itself, this $21 million in additional costs is not a major consideration and could be interpreted to be a break-even result for the region as a whole. Other factors must be considered, however. Wheeling rate impacts are shown in Table 4 as being somewhat positive (the net of the wheeling revenue and wheeling charge impacts is about a positive $16 million). CRA has some concern that loop-flow impacts that cannot be estimated directly using the MAPS simulation model may influence this wheeling rate impact, so this somewhat small impact is considered to be a break-even result.

The major costs associated with this case are the administrative costs that must be undertaken by the individual utilities if SPP were to no longer administer the SPP Tariff. These are reported in Table 4 as being about negative $46 million, meaning that the "benefit" is negative (an increased cost is reported in the table as a negative benefit so that all of the numbers in the table can be added directly instead of adding benefits and subtracting costs). In addition, the SPP withdrawal obligations are shown as an additional cost of $47 million.

These additional costs are offset to some degree by the reduction in FERC fees that would occur under a Stand-Alone scenario, assuming that FERC continues to assess its fees as it does at present. Because 100 percent of load is used by FERC to assess its fees for RTOs, but only wholesale load is used for stand-alone utilities, an appearance is created that a substantial saving in FERC fees would result if the utilities were to revert to a stand-alone status. CRA cannot assess the reasonableness of this estimate, which would appear to be subject to substantial regulatory risk. That is, this impact could effectively be eliminated by a simple change in FERC's assessment approach. CRA has no way to assess whether such a revision in FERC's assessment formula is likely, but we note that this impact is of a purely pecuniary character, as opposed to the real resource costs and benefits measured elsewhere in this study. While such pecuniary impacts are important, they are subject to considerably more uncertainty. So, while Table 4 indicates that the Stand-Alone case would result in about $70 million of additional net costs over the 10-year study period (i.e., a negative $70 million of net benefits), this estimate could easily be closer to $100 million in net costs if FERC were to revise the formula for its fees.

Table 4 Stand-Alone Case, Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Table 5 shows how the net costs (negative net benefits) are allocated to individual utilities within SPP. The results in Table 5 are shown with and without the impact of wheeling revenues and charges. As shown, excluding these wheeling impacts, the benefits of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).

While the aggregate benefit for the transmission owners under the SPP tariff in Table 5 is negative, Kansas City Power & Light and Southwestern Public Service show a moderately positive benefit when wheeling impacts are included. For these companies, the positive result is driven by a significant increase in the wheeling revenues calculated using MAPS tie-line flows when through-and-out wheeling charges to other SPP companies are instituted in the Stand-Alone case. In practice, the increase in wheeling revenues would be associated with a utility that exports significant amounts of power to other SPP companies. Since there are no intra-SPP wheeling charges in the Base case, utilities that export significant amounts of power to other SPP companies would collect considerably more in wheeling revenue in the Stand-Alone case than in the Base case.

However, the change in wheeling rates in the Stand-Alone case and the existence of loop flow together result in considerable uncertainty regarding the wheeling impacts assessed to individual SPP companies. The use of tie-line flows to assess wheeling charge and wheeling revenue impacts when there are loop flows that would not represent actual transactions relies on the presumption that such loop-flow impacts will be similar in the Base and alternative cases and thus will not significantly impact the change in wheeling impacts between cases. However, if there is a significant change in wheeling rates between cases, for example the institution of intra-SPP wheeling charges in the Stand-Alone case, loop flow has the potential to distort measured wheeling impacts. The individual company Stand-Alone results with wheeling impacts included should therefore be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts. The collective Stand-Alone impact across SPP is a better measure than the individual company results, as the intra-SPP wheeling charges paid to or from SPP members offset one another in the collective calculation.

Table 5 Stand-Alone Case, Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling	Wheeling Impacts	Total Benefits
AEP	IOU	(19.8)	(3.0)	(22.8)
Empire	IOU	(5.8)	(19.8)	(25.6)
KCPL	IOU	(17.8)	68.7	50.9
OGE	IOU	(8.2)	(10.4)	(18.6)
SPS	IOU	(5.0)	49.5	44.5
Westar Energy	IOU	(17.0)	0.2	(16.9)
Midwest Energy	Coop	(7.9)	3.9	(3.9)
Western Farmers	Coop	1.3	(52.5)	(51.2)
SWPA	Fed	1.2	(20.9)	(19.7)
GRDA	State	(4.8)	(6.0)	(10.8)
Springfield, MO	Muni	(2.5)	6.1	3.5
Total		(86.3)	15.8	(70.5)

Table 6 shows how the results for the retail customers of the six IOUs in Table 5 are estimated to be distributed among the states in the region. As shown, the impact on most of the states is relatively modest.

Table 6 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars: positive numbers are benefits)

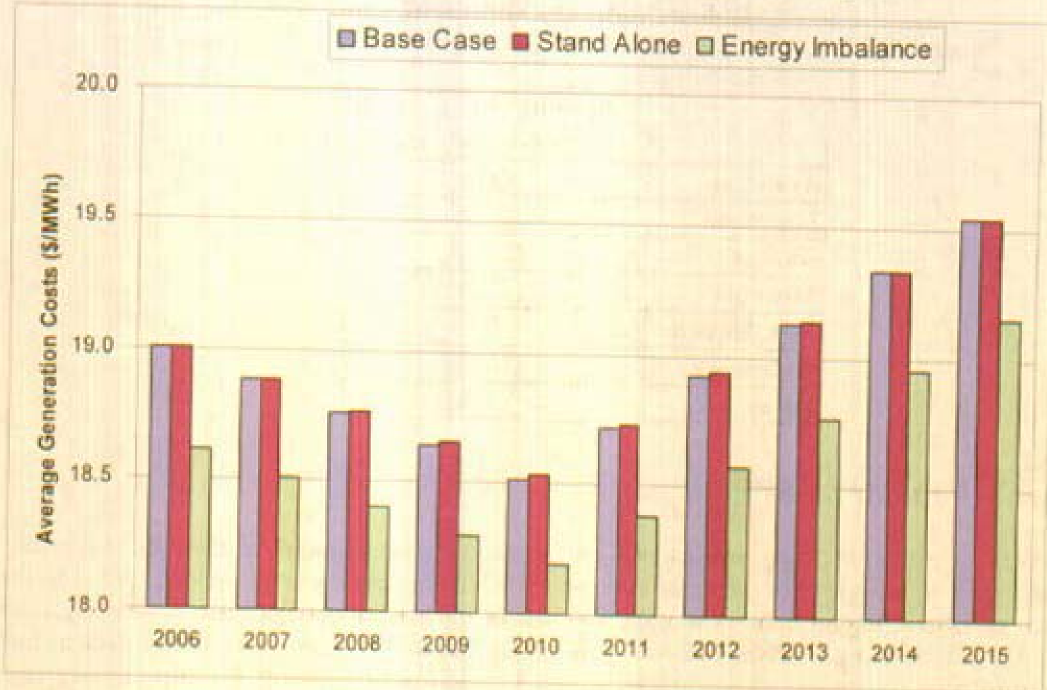
	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

Wholesale Impacts to SPP

The Wholesale Energy Modeling process provided the energy-impact inputs to the allocated results discussed above. It also yields some high-level, region-wide wholesale market metrics related to the three cases simulated. Figure 1 shows the SPP average annual generation cost impacts resulting from the cases. (Note that the trend across the years is primarily due to non-case related factors such as fuel prices, transmission system upgrades, and load growth.) The difference between the respective average cost in each year reflects the fact that the institution of the EIS market increases dispatch efficiency (reduces generation, or production, cost[9]) by approximately 2% ($0.32 to $0.39 per MWh) and decreases SPP spot energy prices by approximately 7%. The Stand-Alone comparison with the Base case did not reveal significant differences. These results are consistent with the level of SPP-wide trade benefits discussed above in the individual case findings.

[9] Generation costs, or production costs, referred to in this report include start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

Figure 1 Wholesale Aggregate Generation Cost Impacts



Qualitative Analysis of EIS Impacts

In addition to the quantified impacts discussed above, the long-run impacts of implementing a formal nodal EIS are expected to include improved transparency and improved price signals. Added complexities may produce adverse impacts during a transition period of roughly 3 to 5 years. In addition, applying explicit imbalance energy prices creates risks for market participants associated with not following schedules and may impede the development of competitive markets if the scheduling requirements are overly burdensome. The movement with the EIS to the centralized management of inadvertent energy will likely be subject to additional production efficiencies that are not captured in the quantitative results of the energy modeling.

Market Power Considerations

CRA has not conducted a formal study of market power in conjunction with this cost-benefit study. Two primary factors, of approximately equal strength, suggest that market power is not likely to become a significant consideration under the EIS market, in particular. These are (1) the provision for an ongoing market monitoring function within SPP and for a separate, independent monitor, and (2) the lack of incentive for the exercise of market power under the economic conditions likely to prevail under the EIS market. Market monitoring is required by FERC and should provide a substantial check on any potential to exercise market power after the implementation of the EIS market. The continuation of cost-based regulation for most of the output of generation in this region means that the EIS market is not likely to augment the incentive to exercise market power in a significant way.

Aquila Sensitivity Case Results

The Aquila wholesale energy market sensitivity case simulations showed that if Aquila were to affiliate with SPP there would be benefits to Aquila, though impacts to the surrounding regions were not necessarily affected in the same direction. The following are the major results.

- The overall benefits of the EIS market for SPP are not particularly sensitive to whether Aquila is in MISO or in SPP.
- While the SPP region's generating costs would be lower with Aquila in MISO (by $10 million under the Base case), Aquila's generating costs would be lower with Aquila in SPP (by $1.7 million in the Base case).
- Spot marginal energy costs are expected to be $0.16/MWh lower with Aquila in MISO under the Base Case and $0.26/MWh lower under the EIS case.
- Aquila companies generate more if in MISO under the Base case, but more if in SPP under the EIS case. (In both cases the change in Aquila generation is less than 1%.)
- Generators in SPP generate at higher levels if Aquila is in SPP than if it is in MISO under both the Base and EIS cases.
- Generation net revenues and the energy cost to serve load also indicate benefits for joining SPP for both Aquila companies.

1 Organizational Outline

This Cost-Benefit analysis report is organized as follows.

- Section 2 provides background and context for the analysis.
- Section 3 describes the energy modeling and the assessment of SPP market design, alternative impacts on energy flows, market dynamics, and energy pricing through the use of General Electric Company's quantitative generation and transmission simulation software, Multi-Area Production Simulation (MAPS). This analysis produced quantitative analytic results based on the economic and physical operation of the regional power system.
- Section 4 describes the benefits (costs) to individual SPP companies and states for the Base, Stand-Alone, and EIS cases.
- Section 5 describes the assessment of other qualitative impacts of the energy imbalance market.
- Section 6 describes the qualitative assessment of the market power impacts.
- Section 7 describes the methodology and results of the Aquila Sensitivity cases.

2 Background

This Cost-Benefit Analysis (CBA) was requested by the Southwest Power Pool Regional State Committee (RSC) to identify the costs and benefits to the State-regulated utilities of maintaining their transmission-owner membership in SPP under different scenarios. Doing that entailed two major activities:

1. Measuring costs and benefits that accrue from consolidated services and functions that include reliability coordination and regional tariff administration. This part of the CBA was accomplished through the development of revenue requirements for each SPP member, as adjusted for known and measurable changes arising from the various scenarios being analyzed, in order to project the results of future operations. The benefits were examined by performing energy system modeling and allocating the resulting costs and benefits to Investor Owned Utilities.

2. Analyzing the costs and benefits of SPP's implementation of a real-time Energy Imbalance Service (EIS) market. This was accomplished by comparing simulated energy benefits allocated to members with costs as reported by members and SPP.

In addition, the study examined the impact of Aquila being part of the SPP RTO.

While many industry cost studies have been done prior to this study, this study uniquely examined the implementation of only a real-time imbalance energy market as well as uniquely measured the impacts of moving back to a stand-alone utility structure. Appendix 2-1 provides a summary of other wholesale electric cost-benefit studies to date.

This report identifies, describes, and quantifies potential incremental costs and benefits with the intention that it be suitable for use by State Regulatory Commissions and/or individual companies in performing their own evaluations or assessments.

SPP is an independent, not-for-profit organization responsible for the reliable transmission of electricity across its 400,000-square-mile geographic area, covering all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas. SPP's membership includes 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three State authorities, and various independent power producers and power marketers. SPP also maintains a coordinating agreement with a federal power marketing agency.[10] In order to assess the benefits of SPP-RTO membership for each member, SPP's Strategic Planning Committee (SPC) decided that the SPP should coordinate a collective analysis to assess the net benefits to its members, rather than require its members to provide individual analyses. To implement this collective approach, the SPP Cost-Benefit Task Force (SPP-CBTF, or CBTF) was formed to select a consultant, if necessary, and to provide additional scope and guidance to the process. Subsequently, the RSC determined that it should contract for the analysis

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[10] SPP and Southwest Power Administration (SWPA) have a coordination agreement in which SPP provides services to SWPA and SWPA complies with SPP's reliability criteria. SPP and SWPA's transmission systems are highly interrelated, and SWPA has on-going relationships with many SPP Transmission Owners.

to support the independence of the study. Charles River Associates' consultants[11] were selected to perform the study. Following the proposed methodology, CRA and the CBTF worked closely to develop the assumptions to be used in the analysis.

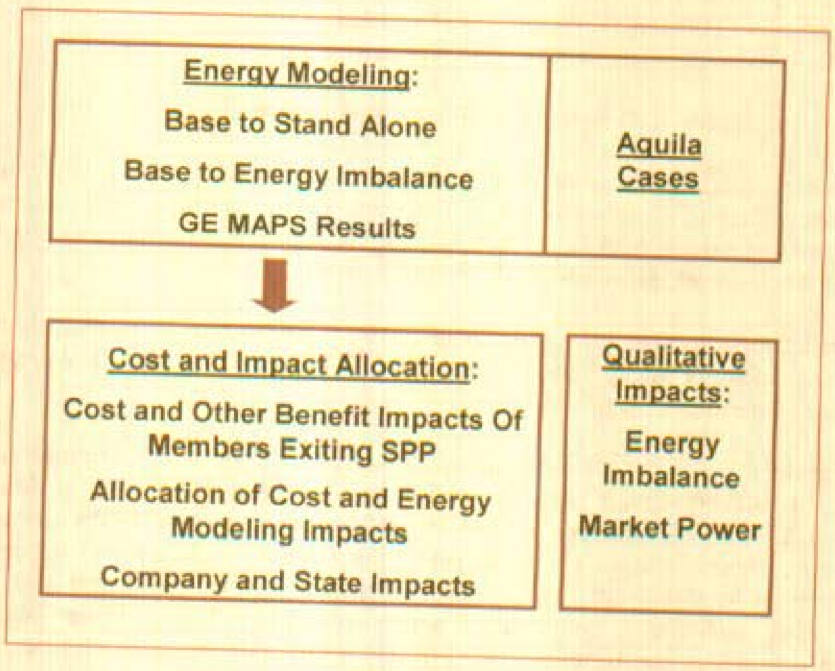
CRA presented status updates and detailed approaches throughout the study period. CRA and the CBTF members reviewed the results and refined the assumptions. This report presents the results of the modeling analyses and of the qualitative Cost-Benefit elements.

2.1 Cost-Benefit Analysis General Approach

This section introduces the general bodies of work constituting the Cost-Benefit analysis.

The SPP CBA consisted of four major elements, all based on a single set of defined cases, as shown in Figure 2-1.

Figure 2-1 Study Elements



Briefly, the study elements are as follows.

[11] Note that Tabors Caramanis & Associates in partnership with Charles River Associates were selected to perform the study. Subsequent to the selection, Tabors Caramanis & Associates was acquired by Charles River Associates.

a) **Wholesale Energy Modeling**—quantified impacts to the energy market, system dispatch, energy prices, and resulting production system costs, and provided the inputs to the allocation of impacts.

b) **Benefits (Costs) Allocation by Company and State**—provided a detailed record of cost and benefit impacts of the cases to the individual companies and to states.

c) **Qualitative Assessment of Energy Imbalance Impacts**—provided qualitative treatment of a variety of other measures of impact of the EIS not captured directly in the energy market modeling or allocations.

d) **Qualitative Assessment of Market Power Impacts**—provided qualitative treatment of the market power impacts of the EIS.

e) **Aquila Sensitivity Cases**—provided impacts on Aquila and SPP of Aquila being integrated into SPP rather than into the MISO RTO. It was decided by the CBTF that Aquila would not be modeled in SPP in the Base Case because it does not currently have its load under the SPP OATT.

A description of each of these five areas follows.

2.1.1 Wholesale Energy Modeling

The energy modeling addressed the expected impacts on the SPP energy market due to the different operational or system configuration assumptions in the various cases. The MAPS analysis included an assessment of the impact on production cost, on the dispatch of the system, and on interregional flows in the study area.

The system production cost associated with each market design alternative served as one metric for comparison among the scenarios. The energy modeling results also served as inputs to the allocation processes for further evaluation of impacts.

CRA modeled three operational market scenarios as part of the study:

- **Base Case:** SPP within its current footprint, no balancing market
- **EIS Case:** Energy Imbalance Service market (real-time) is implemented within today's SPP footprint
- **Stand-Alone Case:** SPP's FERC Order 888 compliant Open Access Transmission Tariff (OATT) is abandoned and each transmission owner operates under its own OATT.

These cases differed in their treatment of one or more of three primary characteristics: transmission wheeling rates, flowgate capacity, and dispatch of non-network generating units. The methodology and results of the wholesale energy modeling are presented in Section 3.

2.1.2 Benefits (Costs) Allocation by Company and State

Section 4 presents the sum of the impacts, including cost and energy modeling impacts. The allocation process distributed impacts across members and by state.

Whereas the wholesale energy modeling produces the system dispatch resulting from the various cases and provides some high-level regional metrics, the allocation process provided detailed company-specific and state metrics based on specific assumptions regarding regulatory policies and the sharing of trade benefits. The major categories of benefits and costs addressed in this study are as follows:

- Trade benefits
- Wheeling charges and revenues
- SPP EIS Market implementation and operating costs
- Individual utility EIS Market implementation and operating costs.

2.1.3 Qualitative Assessment of Energy Imbalance Impacts

Section 5 describes the assessment of energy imbalance market impacts other than those quantified in the modeling and allocation portions of the study. That is, while the energy market simulations addressed the energy efficiency aspects of the market design changes, there are other potential impacts that the simulation was not intended to address. The qualitative analysis results in a matrix of evaluations in which CRA consultants examined, on one hand, a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against, on the other hand, a variety of metrics (such as volatility, risk, and competition).

2.1.4 Qualitative Assessment of Market Power Impacts

The Market Power Impacts section addresses the likelihood that the implementation of an EIS in SPP would enhance the potential for the exercise of market power in the SPP region, especially in the context of the market monitoring function and the continuation of cost-based regulation in this region.

2.1.5 Aquila Sensitivity Cases

Section 7 presents the results of the sensitivity cases in which Aquila is considered to be part of SPP rather than part of the MISO RTO. The SPP regional wholesale energy modeling results and the wholesale impacts on Aquila are provided. The sensitivity analysis is performed for the Base and EIS cases.

3 Wholesale Energy Modeling

CRA conducted a quantitative energy modeling of the SPP system under three scenarios: a Base case in which SPP continues to operate as an RTO; a Stand-Alone case, in which the members of SPP revert to operating as individual FERC Order 888 compliant transmission providers; and an EIS case in which SPP implements a formal energy imbalance market. The wholesale energy modeling used the MAPS model[12] and incorporated the operating procedures transmission constraints currently used in SPP. The analysis is intended to provide insight into the economic operation of the SPP energy market under each scenario.[13]

The results of the analysis are based on model representations and input assumptions developed through extensive discussions with the CBTF members and SPP operations and planning staff. The market design for the Base case was defined based on current operating practices. The design for the Stand-Alone case was based on input from the CBTF members about likely changes should members revert to acting alone. It was assumed that under the Stand-Alone case SPP would continue to act as a reliability coordinator and that members would participate in reserve sharing.[14] The Energy Imbalance case was modeled assuming that the system was dispatched centrally based on a least-cost representation. The final assumptions were ones that the SPP and utility members of the CBTF considered reasonably expected conditions for the years 2006 through 2015.

3.1.1 Input Assumptions

The following input assumptions were used in the wholesale energy modeling:

Company-specific load and energy forecasts based on 2004 EIA-411 data as provided by SPP for SPP companies, and most recent available EIA-411 data from the CRA data archive for areas outside of SPP

- 2002 hourly load shapes based on FERC 714 filings, as represented in the CRA data archive
- Gas and oil forecasts as described in the forecast memo
- Generation bids based on marginal cost[15] (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits)
- Coal forecast as obtained from Resource Data International
- Transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by SPP

[12] MAPS is the Multi-Area Production Simulation software developed by General Electric Power Systems and proprietary to GE.

[13] MAPS does not simulate the regulation market, nor does it reflect AC system constraints such as the reactive power needs of the system.

[14] Operating Reserves are needed to adjust for load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales. The SPP Reserve Sharing Program establishes minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group. The SPP Reserve Sharing Program assures that there are available at all times capacity resources that can be used quickly to relieve stress on the interconnected electric system during an Operating Reserve Contingency. According to the SPP reserve sharing criteria, pool-wide reserve requirements are set as the size of the largest contingency plus one-half of the second-largest contingency. These requirements are then allocated among control areas in proportion to peak demand.

[15] Cost does not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

- Environmental adders based on forecast emissions values[16]
- New generation additions already under construction based on public information and validated with the CBTF[17]

Appendix 3-1 (Input Assumptions) and Appendix 3-2 (Fuel Forecast Memo) give details of these and other inputs to the model.

3.1.2 Case Descriptions for Base case, Stand-Alone case, and EIS case

In distinguishing among these scenarios, CRA worked with three categories of modeling assumptions:

a) Application of wheeling charges
b) Effective flowgate capacity
c) Dispatch of non-network generating units

Table 3-1 indicates how these assumptions were treated in each scenario.

Table 3-1 Scenario Matrix

	Base Case	EIS Case	Stand-Alone Case
Application of wheeling charges	No wheeling charges between SPP members	No wheeling charges between SPP members	Area[18]-to-area wheeling charges (footnote the definition of Area)
Specification of flowgate capacity	Reduced flowgate capacity	Full flowgate capacity	Reduced flowgate capacity
Dispatch of non-network generating units	Sub-optimal	Optimal	Sub-optimal

Each of the three areas of distinction is discussed further below.

Wheeling charges. In MAPS, wheeling charges are calculated as a per-MW price adder for net flows from each area to each neighboring area, based on the definition of the control areas in the

[16] Emission rates are based upon EPA's Clean Air Markets database for 2002 and include future upgrades to emission control technology only if reported in this database. Future rates do not include any environmental controls likely to be required under the current Clean Air Interstate Rules, nor were any additional environmental controls included to reflect pending regulation and/or legislation

[17] Recently constructed combined cycle units were modeled with a heat rate and O&M costs characteristic of baseload combined cycle units. However, these units were not restricted to base load operational behavior, so it is possible that the production costs associated with these units may be underestimated relative to actual operations.

[18] Areas are defined in the power flow case supporting market simulations with MAPS. As a rule, areas specified in the power flow case correspond to control areas. MAPS determines tie-lines between areas and assesses user-defined wheeling charges on the net power flow across these tie-lines.

AC power flow case. MAPS automatically defines interfaces between areas, and CRA defined wheeling rates for each interface based on the scenario modeled and on the appropriate transmission tariff wheel-out rate.

Effective flowgate capacity. For the suboptimal dispatch cases (Base and Stand-Alone), transfer limits on all flowgates in the SPP region were decreased by 10% to reflect the inefficiency of congestion management through the TLR process. The 10% figure was determined in consultation with SPP based on historical tie-line flows during TLR events. Because of uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in this process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

Optimal vs. Sub-optimal dispatch of non-network generating units. MAPS models the optimal operation of an electric power system without regard to ownership or distinctions in priority and/or transmission network access rights among generating units. Under current SPP rules, however, resources designated as "network resources" for serving native load are given priority access to the transmission system in times of scarcity. It is generally assumed that network resources gain access to the transmission system and are dispatched on an economic basis. Resources that do not have network status receive access to the transmission system on a "first come, first served" basis, subject to the availability of transmission capacity. In order to simulate such a sub-optimal market outcome, the following approach is implemented:

- First, the system is simulated under conditions of optimal, security-constrained, non-discriminatory transmission access for all generating resources. This is identical to assuming the presence of an SPP-wide energy market, in which all committed generating units are dispatched to minimize system-wide production cost subject to transmission constraints. Congestion is relieved in real time on an economic basis in accordance with LMP market signals.

- Second, the system is simulated under the condition where two operational limitations are explicitly implemented in the model:
    - Generating units that do not have network status[19] but that adversely impact limiting transmission constraints are allowed to generate only to the extent that their impact on scarce transmission resources is minimal.[20] The effect is that these resources are dispatched only if they can obtain Available Transfer Capability (ATC), calculated on the basis of network resources having been dispatched first.[21] Given the modified dispatch of units that do not have network status, the rest of the system is redispatched so that the output reduction for non-network units is compensated by increased output of units that do have network status. This redispatch defines the sub-optimal case of the corresponding scenario.
    - In that second (sub-optimal) redispatch, operational limits on SPP flowgates are reduced from their operational limits by 10%, because congestion on these lines

[19] The list of non-network units was generated with extensive consultation with the CBTF.
[20] "Minimal impact" is defined as a flow of no more than 5% of the flow limit on any limiting resource.
[21] No firm economic purchases from the set of non-network units were assumed. To the extent that utilities purchase power from non-network resources to serve firm load and provide high-priority transmission access for this power under current market conditions, the savings between the Base case and the EIS case could be overstated.

is managed through the less-efficient transmission-line relief (TLR) process rather than through LMP-based generation redispatch.

Note that none of the cases included a "hurdle rate other than the tariff wheeling rates applied in the Stand-Alone case. Hurdle rates are non-tariff wheeling rates which are sometimes implemented in market simulations to represent unspecified or difficult-to-model inefficiencies or other barriers to trade. CRA and the CBTF discussed at length the use of a hurdle rate. However, CRA preferred implementing a method that emulated actual market characteristics (network access and conservative line loading under certain cases). As a result, the cases were represented by CRA as described above. Following the implementation of the methodology described above, the utility members of the CBTF reviewed the preliminary results of the simulations and found that simulated inter-control area flow patterns closely matched historical patterns. Based on this review, the addition of a simulation hurdle rate was determined to be unnecessary.

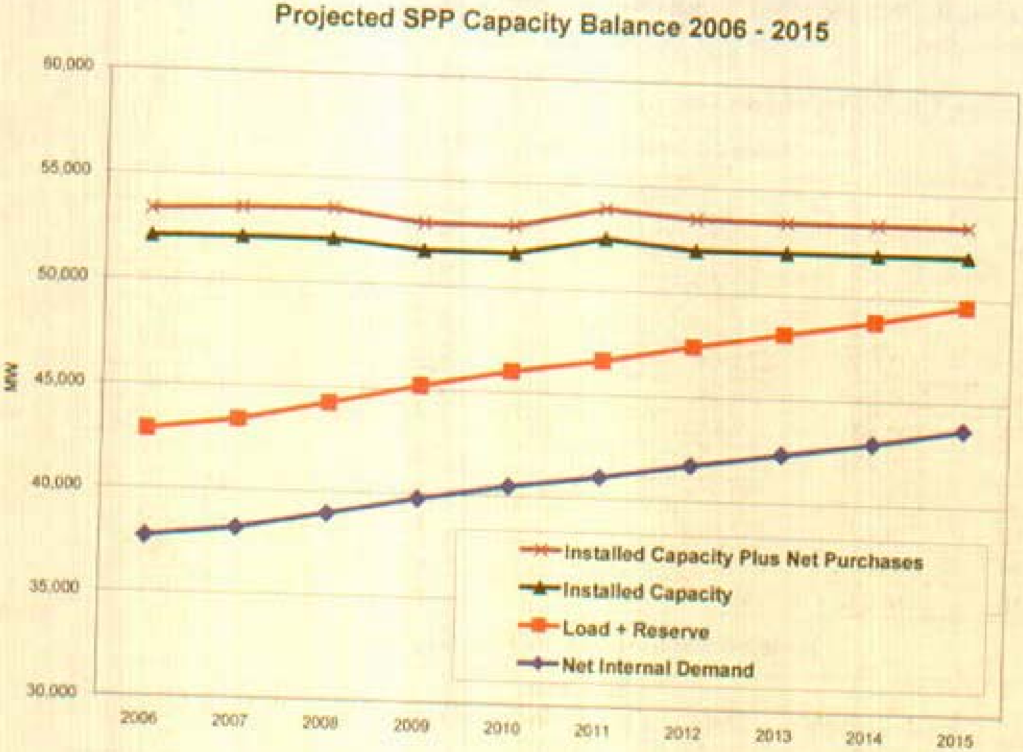
Note also that in each of modeling scenarios it is assumed that the entire volume of the market is cleared through the simulation's spot market. To the extent that transmission owners' self-dispatch and self-deployment is efficient and to the extent that the bilateral market is efficient, the results should emulate the existing market structures. However, to the extent that the bilateral markets are less efficient than the simulated result—and especially to the extent that one might expect the bilateral market efficiency to change with these cases—the actual results may deviate from the simulated results.

3.1.3 Resource Additions

Figure 3-1 summarizes the capacity balance forecast CRA prepared for the SPP region. The forecast is based on information provided by SPP companies with respect to peak demand requirements, generation capacity available to meet these requirements (including both company designated generating units and merchant power plants in SPP), and projected levels of firm purchases and sales.[22] The forecast included Cleco but not Aquila companies. The figure only reflects the addition of 30 MW of the Sunflower Windfarm in 2005 and 800 MW of Iatan 2 coal fired facility scheduled for 2010. It also reflects anticipated retirement of 430 MW of Teche generating units in 2008 and 440 MW of Rodemacher 1 generating unit in 2011. The overall projected capacity balance indicates that the capacity surplus will likely prevail over the study period. The assumed future mix of installed capacity will be more than sufficient for meeting SPP reliability requirements. That eliminated any need for modeling the entry of new generation in SPP. CRA also did not model generation retirements. A proper modeling of generation retirements would require making explicit assumptions with respect to the capacity market under each scenario considered. In absence of the capacity market model, economic retirement of generation cannot be assessed. Given that the capacity market could not be modeled consistently across all scenarios, and that the assessment of such a market is beyond the scope of this study, CRA decided not to model economic retirement of generating facilities in SPP.

[22] Net internal demand Peak demand, purchases, and sales data are per Form EIA 411 filings by SPP companies. Installed capacity in the study was based on CRA MAPS database and direct inputs by study participants.

Figure 3-1 Capacity Balance



3.2 Wholesale Energy Modeling Results

This section summarizes region-wide results of the MAPS wholesale energy modeling. Section 4 provides the detailed allocated results of the energy impacts. As is the case throughout this report, all financial values shown in this section are in real year-2003 U.S. dollars.

The quantification of benefits from the MAPS analysis is based on comparisons between the three cases[23] and includes generation production cost, regional generation, and the average spot market prices for energy. The comparisons are made across the SPP system.

The wholesale energy market modeling yields both high-level regional metrics and outputs that feed the detailed allocation results. Metrics include both physical metrics (generation in SPP or imports, and emissions impacts) and financial impacts such as prices.

[23] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, because the great majority of parameters act equally in all cases. By examining differences between the cases, therefore, one can eliminate adverse impacts of a majority of modeling assumption inaccuracies.

3.2.1 Physical Metrics

This section presents both the physical market-wide impacts and the SOx and NOx production for SPP for all three cases.

Tables 3-2 through 3-6 give the physical metrics.

Table 3-2 Base Case Physical Metrics

Base Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,518	218,439	19,921	283,538	449,349
2007	201,109	221,942	20,834	282,606	446,861
2008	203,699	225,446	21,746	281,675	444,373
2009	206,290	228,949	22,659	280,744	441,886
2010	208,881	232,453	23,572	279,813	439,398
2011	210,828	235,843	25,016	282,211	442,057
2012	212,774	239,234	26,459	284,608	444,717
2013	214,721	242,624	27,903	287,006	447,376
2014	216,668	246,015	29,347	289,404	450,036
2015	218,615	249,405	30,791	291,802	452,695

Table 3-3 Stand-Alone Case Physical Metrics

SA Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,168	218,439	20,271	283,650	449,343
2007	200,825	221,942	21,117	282,903	447,162
2008	203,482	225,446	21,964	282,155	444,981
2009	206,139	228,949	22,810	281,408	442,800
2010	208,796	232,453	23,657	280,660	440,620
2011	210,686	235,843	25,158	282,954	443,094
2012	212,575	239,233	26,658	285,249	445,568
2013	214,465	242,624	28,159	287,543	448,042
2014	216,354	246,014	29,660	289,837	450,516
2015	218,244	249,405	31,161	292,131	452,991

Table 3-4 Imbalance Energy Case Physical Metrics

EIS Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	201,126	218,439	17,313	276,929	449,010
2007	204,115	221,942	17,827	275,616	446,033
2008	207,104	225,446	18,342	274,303	443,055
2009	210,092	228,949	18,857	272,990	440,077
2010	213,081	232,453	19,372	271,677	437,099
2011	215,348	235,843	20,495	273,580	439,816
2012	217,615	239,234	21,619	275,483	442,532
2013	219,881	242,624	22,743	277,385	445,249
2014	222,148	246,015	23,867	279,288	447,966
2015	224,414	249,405	24,991	281,191	450,682

Tables 3-5 and 3-6 show the differences in the physical metrics between the Stand-Alone and Base cases and between the EIS and Base cases.

Table 3-5 Impact of Stand-Alone Case - Physical Metrics

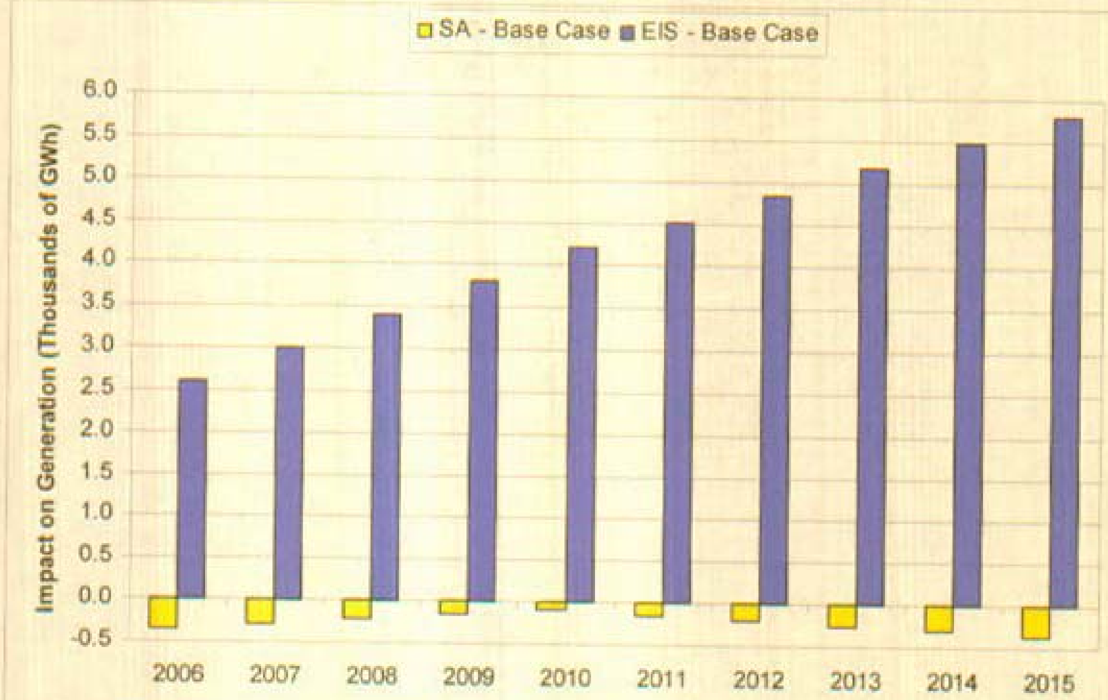
Impact (SA – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	(350)	113	(6)
2007	(284)	296	301
2008	(217)	480	608
2009	(151)	664	915
2010	(85)	848	1,222
2011	(142)	744	1,036
2012	(199)	640	851
2013	(256)	536	666
2014	(314)	433	481
2015	(371)	329	295

Table 3-6 Impact of EIS case—Physical Metrics

Impact (EIS – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	2,608	(6,608)	(338)
2007	3,006	(6,990)	(828)
2008	3,404	(7,372)	(1,318)
2009	3,802	(7,754)	(1,809)
2010	4,200	(8,136)	(2,299)
2011	4,520	(8,631)	(2,242)
2012	4,840	(9,126)	(2,185)
2013	5,160	(9,621)	(2,127)
2014	5,480	(10,116)	(2,070)
2015	5,800	(10,611)	(2,013)

Figure 3-2 shows the results of the different cases.

Figure 3-2 Impact of Stand-Alone (SA) and EIS cases on Generation in SPP Region

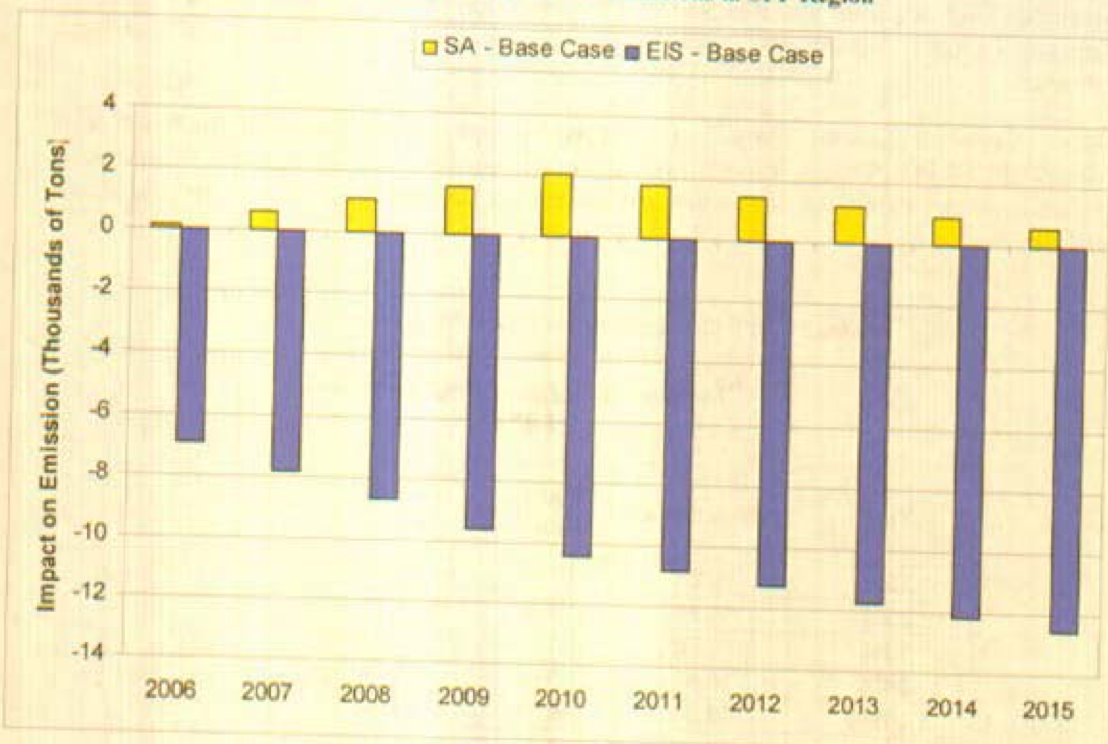


The simulations showed that generation within SPP would decrease were SPP to move from an RTO structure to a Stand-Alone structure in which wheeling rates would again exist between utilities that were previously SPP members. It is likely that with the added wheeling rates, the cost of production plus transmission renders power from SPP sources less competitive relative to generation outside of SPP, so that generation outside of SPP displaces generation within SPP.

In the EIS, case, however, an opposite result occurs. The EIS case results in a marked increase in generation in the SPP region due to the increased efficiency of the SPP dispatch as a result of the improved operation of the flowgate constraints and the increased ability for non-network units to be dispatched economically.

Figure 3-3 shows the impact of the Stand-Alone (SA) and EIS (EI) cases on regional emissions.

Figure 3-3 Impact of Cases on Emissions in SPP Region



The Stand-Alone case, given its further departure from the dispatch efficiency of the Base case due to wheeling rates, results in higher total emission in the SPP region. (Table 3-5 indicates that the increase is essentially equally spread between NOx and SOx emissions increases.) The modeling indicates that the movement to an imbalance energy market would result in a significant (up to 4%) decrease in emissions. Table 3-6 indicates the majority of the decrease is in NOx emissions. This is due to the shift in generation away from older, less efficient and higher emitting, steam-gas units in the Base case to more efficient, cleaner combined cycle units in the EIS case.

3.2.2 Annual Generation Costs—a critical economic indicator

Annual generation cost is a critical economic indicator. It is easy to interpret and it clearly represents a social gain (social welfare gain) to the region as a whole. In this study the terms "generation cost" and "production cost" are used interchangeably. The generation cost or production cost is for each generating unit includes start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

Table 3-7 and Table 3-8 show the SPP generation costs24 by case and the impact on generation costs for the Stand-Alone and EIS cases, respectively. Figure 3-4 shows the average annual SPP generation cost for each case, and Figure 3-5 shows the cost differences between the Base case and the Stand-Alone and EIS cases.

Table 3-7 SPP Generation Cost ($/MWh) by Case

	Average Generation Cost Summary ($/MWh)		
Year	Base Case	Stand-Alone	EIS
2006	19.01	19.00	18.61
2007	18.88	18.88	18.51
2008	18.76	18.77	18.40
2009	18.64	18.65	18.30
2010	18.51	18.54	18.19
2011	18.72	18.74	18.38
2012	18.92	18.94	18.58
2013	19.13	19.14	18.77
2014	19.33	19.34	18.96
2015	19.54	19.54	19.15

[24] In the allocation analysis, all control areas are defined to correspond with the areas defined in the load flow case, and units are assigned to companies in accordance with their electrical locations regardless of financial ownership. This is required for alignment with tie line flows, which are defined according to the load flow case areas. In contrast, the wholesale market analysis identifies units according to ownership data provided by the CBTF. Because of this, some differences in electrical output and generation cost by company and over SPP will be found between the two analyses.

Table 3-8 Impact of Cases on Average Generation Cost in SPP ($/MWh)

	Impact on Generation Cost ($/MWh)	
Year	**SA – Base**	**EIS – Base**
2006	(0.005)	(0.39)
2007	0.002	(0.37)
2008	0.008	(0.36)
2009	0.015	(0.34)
2010	0.021	(0.32)
2011	0.016	(0.34)
2012	0.012	(0.35)
2013	0.007	(0.36)
2014	0.003	(0.37)

Figure 3-4 SPP Generation Cost ($/MW) by Case

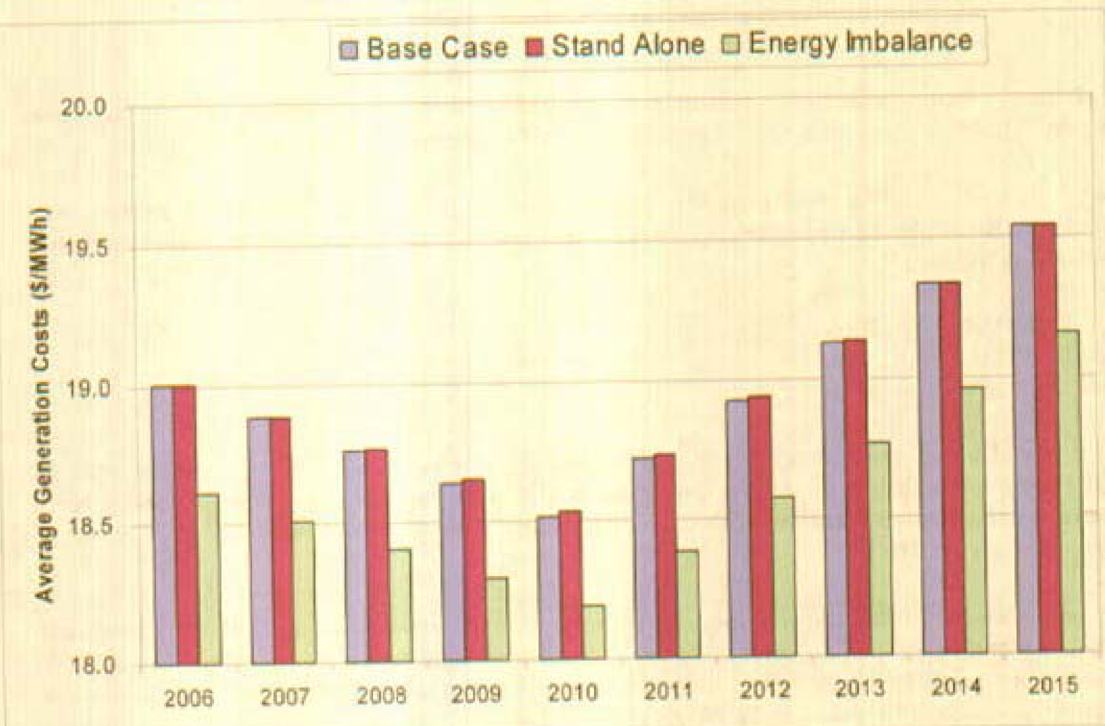
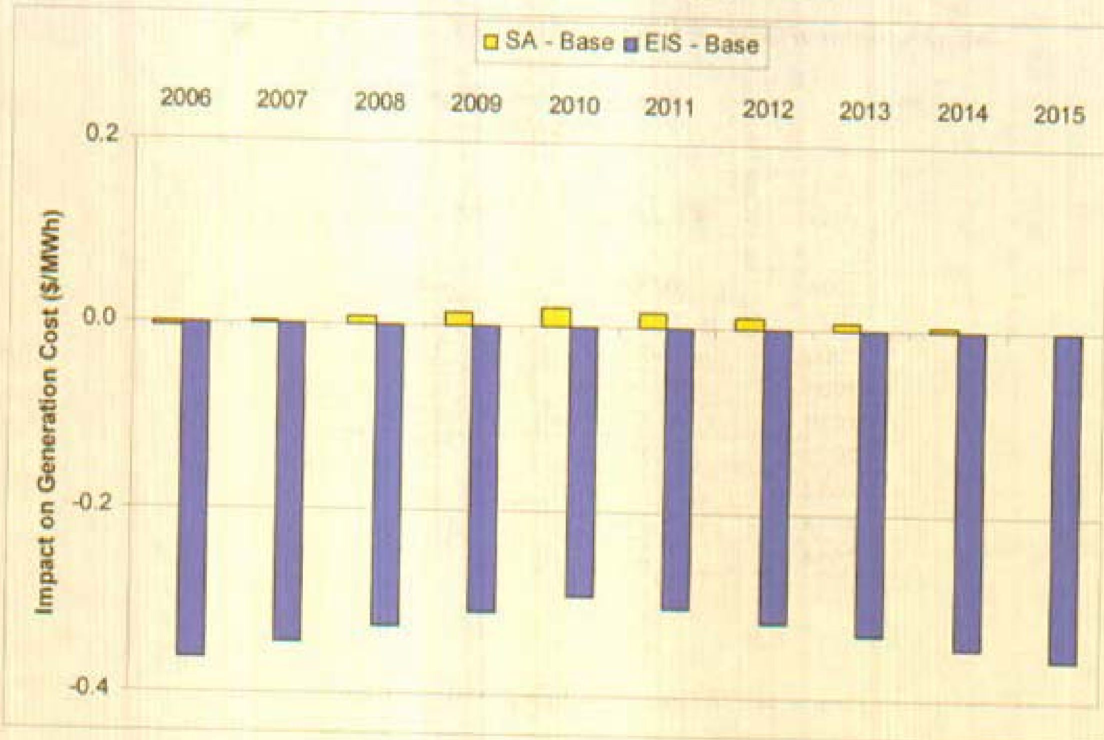


Figure 3-5 SPP Generation Cost ($/MWh) Differences



The wholesale results indicate a year-by-year pattern, as well as regular pattern in the case differences. There are three main factors behind the year-by-year trend of the cost differences.

- First, generation costs, and therefore generation cost differentials between scenarios, are significantly influenced by underlying forecast fuel prices. Assumed natural gas prices at Henry Hub are as follows:

  - $5.54/MMBtu in 2006
  - $4.24/MMbtu in 2010
  - $4.47/MMbtu in 2014

  That would imply generation costs in 2006 being higher than in 2010 and generation costs in 2010 being lower than in 2014. The same pattern will likely apply to changes in generation costs between scenarios—the change in 2006 would be higher than in 2010, then change in 2010 would be lower than in 2014.[25]

- Second, changes in the transmission system occur over the study horizon. The load flow case used to simulate years 2010 and 2014 includes transmission upgrades not available in 2006. Simulations for 2010 would reflect these transmission upgrades and therefore could exhibit less transmission congestion than in 2005. As discussed above, sub-optimal dispatch underlying the Base case modeling is primarily influenced by transmission congestion; lower congestion implies

[25] It is important to note that direct simulations were performed for 2006, 2010, and 2014 only. Results for other years are based on interpolation and/or extrapolation.

smaller differences between EIS and Base case scenarios, as can be observed in comparing years 2006 and 2010.

- Third, there is load growth requiring greater generation output but not supported by further transmission upgrades: simulations for 2010 and 2014 were made using the same load flow case. That implies higher congestion in 2014 than in 2010. Higher congestion in turn implies less efficient use of non-network generators and therefore greater difference between the Base and EIS case scenarios in 2014 than in 2010, as can be seen in Figure 3-5.

Implementation of the EIS market yields a saving of $0.36 per MWh on average. The relative magnitude of the generation cost difference between the Base and Stand-Alone cases is essentially negligible (less than 0.01%). Thus the modeling found no significant *region-wide* impact of moving from the Base case to the Stand-Alone case.

3.2.3 Wholesale Spot Energy Price Changes

This section presents the impacts on the spot price[26] of energy in SPP from the three cases. Table 3-9 shows the average annual energy cost in the SPP region under each case, and Table 3-10 shows the change in spot price, relative to the Base case, for the Stand-Alone and EIS cases.

Table 3-9 Average SPP Spot Load Energy Price

	Costs of Served Load Summary ($/MWh)		
Year	**Base Case**	**Stand-Alone**	**Energy Imbalance**
2006	40.85	40.95	38.32
2007	39.96	40.07	37.49
2008	39.06	39.19	36.67
2009	38.16	38.31	35.85
2010	37.27	37.43	35.03
2011	37.92	38.01	35.45
2012	38.57	38.59	35.87
2013	39.22	39.18	36.29
2014	39.87	39.76	36.71
2015	40.53	40.34	37.13

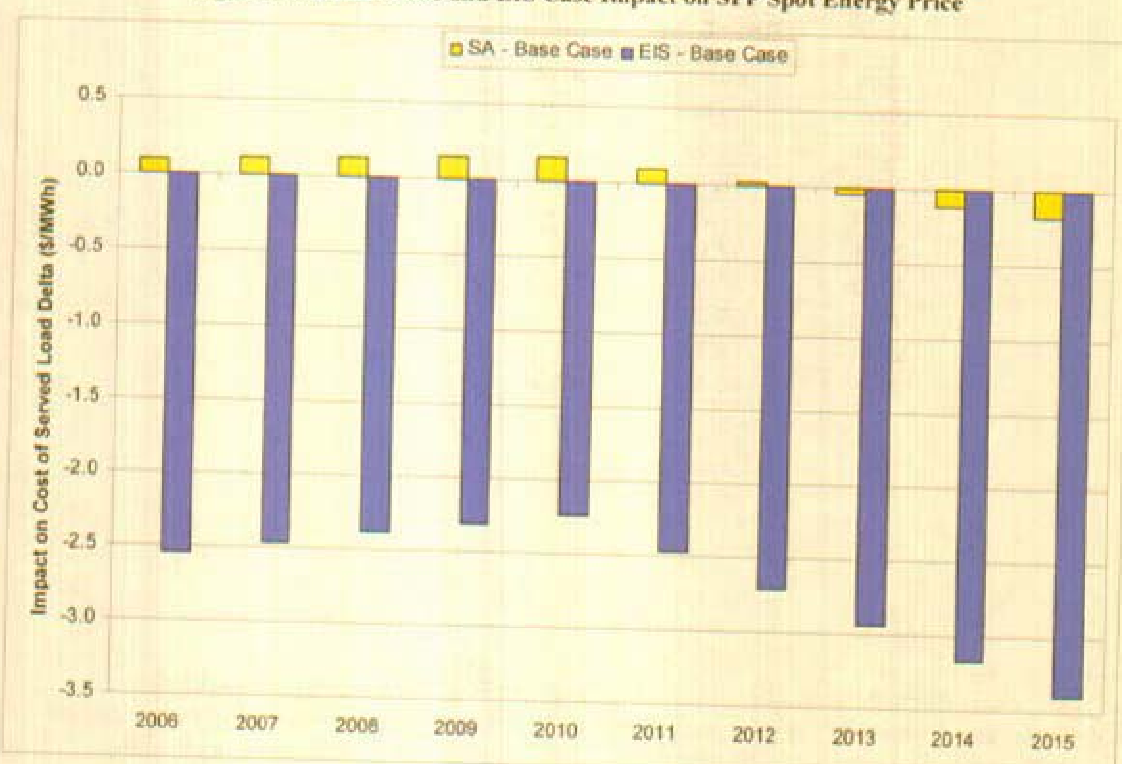
[26] The "spot price" refers to the locational price of energy (in $/MWh) as calculated under the locational marginal price (LMP) system, assuming cost-based, security constrained optimal dispatch of the system. While a spot price can be calculated for any point in the system, it is not generally reflective of the cost of production at that location, but it is reflective of the marginal cost of increasing consumption at that location.

Table 3-10 Case Impacts on SPP Spot Energy Price

Average Cost of Served Load Delta ($/MWh)		
Year	**SA - Base case**	**EIS - Base case**
2006	0.09	(2.54)
2007	0.11	(2.46)
2008	0.13	(2.39)
2009	0.14	(2.31)
2010	0.16	(2.24)
2011	0.09	(2.47)
2012	0.02	(2.70)
2013	(0.04)	(2.93)
2014	(0.11)	(3.17)
2015	(0.18)	(3.40)
Average	**0.04**	**(2.66)**

Figure 3-6 shows the impact of the Stand-Alone and Energy Imbalance cases on the average load spot energy price in SPP.

Figure 3-6 Stand-Alone and EIS Case Impact on SPP Spot Energy Price



Note that the general patterns of the impacts are similar to those shown for generation costs in Figure 3-5, but that the regional load marginal energy cost differences between the cases are significantly higher because of the model's marginal pricing of spot energy to loads. For the Energy Imbalance case, the spot price for loads is over $2.50/MWh (about 7%) less expensive than under the Base case scenario on average over the study horizon.

3.2.4 Impact on the Marginal Value of Energy Generated

Similar to Section 3.2.3, this section provides the impacts of the cases to the marginal value of energy at the generation sources. Table 3-11 shows the average marginal value of the energy for all generation in SPP and Table 3-12 shows the difference in marginal value of the generation between the cases. These results indicate how the spot value of energy at the generating locations is impacted by the cases in the simulations.[27]

Table 3-11 Average Marginal Value of Energy Generated

Average Marginal Value of Energy Generated ($/MWh)			
Year	Base Case	Stand Alone	Energy Imbalance
2006	37.40	37.28	35.39
2007	36.55	36.47	34.64
2008	35.73	35.68	33.91
2009	34.93	34.92	33.19
2010	34.15	34.17	32.50
2011	34.70	34.65	32.81
2012	35.35	35.22	33.21
2013	35.99	35.78	33.60
2014	36.62	36.34	33.99
2015	37.23	36.88	34.37
Average	**35.86**	**35.74**	**33.76**

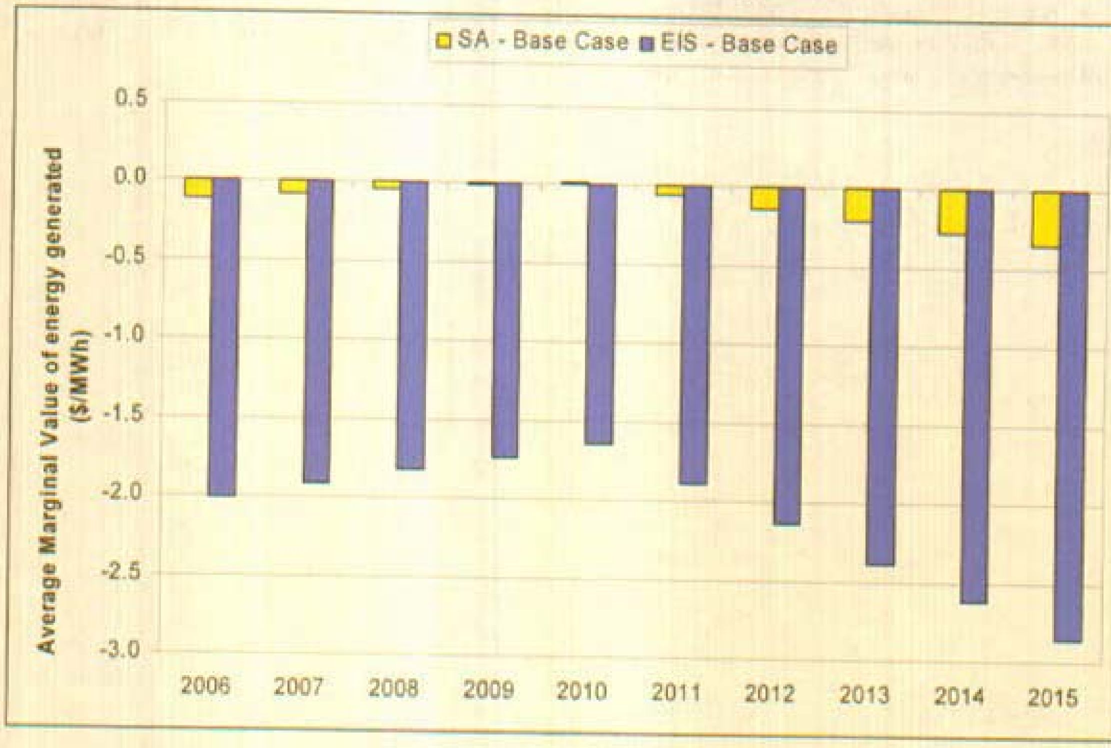
[27] Recall that the simulated values are based on the assumption that generating units bid marginal cost.

Table 3-12 Average Marginal Value Delta

Average Marginal Value Delta of Energy Generated ($/MWh)		
Year	**SA - Base Case**	**EIS - Base Case**
2006	(0.12)	(2.01)
2007	(0.08)	(1.91)
2008	(0.05)	(1.82)
2009	(0.01)	(1.74)
2010	0.02	(1.65)
2011	(0.06)	(1.90)
2012	(0.13)	(2.14)
2013	(0.21)	(2.39)
2014	(0.28)	(2.63)
2015	(0.35)	(2.86)
Average	**(0.13)**	**(2.11)**

Figure 3-7 shows the differences in marginal energy value between the cases. The figure reflects the fact that the value of energy for generators is lower in the EIS case than in the Base case (on average by $2.11). The value of energy to the generators simulated in the Stand-Alone case is also lower than in the Base case. The imposition of wheeling rates in the Stand-Alone case causes the marginal value of energy at the generators to increase for some companies and to decrease for other companies. Figure 3-7 simply shows the result of these impacts and indicates that the total average marginal generation energy value happens to be slightly lower under the Stand-Alone case.

Figure 3-7 Average Marginal Value of Energy Generated



3.2.5 Outputs to Allocation Model

In addition to providing high-level regional indicators of the impacts of each of the cases, the Wholesale Energy Modeling provided critical inputs to the allocation processes that led to company and state-specific impacts. These inputs include the following:

- Generation
- Generation cost (including emission costs)
- Nodal locational marginal prices
- Hourly tie-line flows
- Annual generating unit reports including dispatch, cost and revenue data by plant
- Load

3.3 Wholesale Energy Modeling Conclusions

The wholesale energy modeling SPP generation cost and spot energy price metrics indicate that the Energy Imbalance market increases the dispatch efficiency (reduces dispatch cost) by approximately 2% and decreases SPP spot energy prices by approximately 7%. These are significant differences. The differences between the Stand-Alone and Base case metrics were much smaller than those between the Base Case and EIS scenarios. Thus, in the absence of an Energy Imbalance Service market, reversion to a Stand-Alone mode of operation would not appear to have a significant adverse impact on regional dispatch efficiency. However, as discussed in Section 4, reversion to a Stand-Alone mode would create significant shifts in generation costs between transmission owners, merchant generators, other SPP market participants, and neighboring regions.

4 Benefits (Costs) by Company and State

4.1 Methodology for Measuring Benefits (Costs)

Welfare for regulated customers of a utility, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits to the regulated utility are passed through to its native load. If these charges decrease, regulated customer welfare increases. This study assesses the benefits and costs associated with load-serving utilities moving from base conditions to stand-alone status and from the base conditions to participation in the EIS market. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation or production costs, energy purchases, wheeling charges, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, wheeling charges and revenues, SPP implementation and operating costs, and individual utility implementation and operating costs. Trade benefits and wheeling impacts were computed using the MAPS results for each case.[28] The changes in SPP costs from the Base to the Stand-Alone case and from the Base to the EIS case were estimated using projected SPP budgets. Individual company changes in operating and capital costs that would take place under stand-alone status and under participation in the EIS market were projected by each company, reviewed by CRA for consistency in approach, and converted to revenue requirements. The methodology used to estimate the impact of each major category of benefits and costs is discussed below.

4.1.1 Trade Benefits

The cases analyzed in this study (Base, Stand-Alone, and EIS) reflect varying degrees of impediments to trade between regions. In particular, the institution of intra-SPP wheeling rates in the Stand-Alone case results in greater impediments to trade between utility areas, and institution of the EIS market results in reduced impediments to trade between utility areas. Reductions in the impediments to trading between utilities should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

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

[28] MAPS runs were completed for the years 2006, 2010 and 2014. The results for the intervening years were interpolated on a straight-line basis using the results in 2003 dollars, and then an annual inflation rate of 2.3% was applied. Results for the year 2015 were obtained by escalating 2014 results at the annual inflation rate.

cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits. While production cost changes cannot be used directly to allocate trade benefits to individual utility areas, the individual utility trade benefits will sum to the change in aggregate production cost.[29]

In this study, merchant plants are assumed to be participating in the wholesale market based upon market-driven pricing in the Stand-Alone, Base, and EIS Market cases. All utility-owned plants are assumed to have an obligation to serve native load under cost-based regulation. Benefits are therefore calculated as if all trade gains earned by utilities accrue to the benefit of native load. This means that benefits have not been separated between those that might accrue to the utility in comparison to those that that might accrue to that utility's native load.

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

In this study, trade benefits are allocated primarily among utilities within SPP and control areas with direct interties with SPP based on the change in utility generation between the base and change cases.[30] This presumes that trading margins are similar throughout the SPP region. This approach differs from that used in CRA's SEARUC cost-benefit study, which was based on using a 50-50 sharing rule and tie-line flows as a proxy for transactions between adjoining control areas. Our consideration of using a similar method within SPP indicated that loop flow effects are important within this compact region and would prevent a successful application of the SEARUC approach without substantial modification. CRA believes that the assumption of a similar trade margin throughout SPP provides a good first approximation of how aggregate trade benefits are likely to be distributed within SPP. Improving on this estimate would require additional study to determine how the loop flow issue could be addressed in greater detail.

In particular, this study assumes that trade gains are shared among control areas in proportion to the magnitude of the absolute value of the change in generation output. This means that control areas that

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

[30] For purposes of this study, the change in utility generation was assessed on an annual basis. This allocation could be further refined through the use of a monthly or hourly allocation.

sell more energy (those whose generation increases) and control areas that buy more energy (those whose generation decreases) share the trade benefits equally for each megawatt-hour of change in generation output. Within each control area, trade benefits associated with changes in utility-owned generation accrue to native load. This is consistent with traditional trading between utilities using a 50-50 sharing arrangement. The only difference between this approach and that used in the SEARUC study is that the 50-50 sharing rule is implemented in this study based on changes in each utility's position as a net buyer or seller, while the 50-50 sharing rule in the SEARUC study was implemented between interconnected pairs of utilities. The level of aggregation used in the allocation of the trade benefits is higher in this study, but the underlying approach is the same—a 50-50 sharing rule.

The study makes the additional assumption that merchant units participate in the EIS market in a particular way. The EIS market will provide an SPP-wide opportunity for merchant units to participate in an organized spot market for energy. However, it is expected that most merchant plants will do so through some type of contractual arrangement with utilities on behalf of their native load. CRA does not have any information about the potential nature of such contractual arrangements. However, it is unlikely that merchant plants would participate in an imbalance market for energy if that market were the sole source of merchant revenue. Merchant plants likely would seek additional revenue through contractual arrangements with native load.

Accordingly, CRA has assumed that merchants participate in the EIS under a two-part pricing arrangement. First, the merchants are paid their respective locational wholesale price for any energy that they produce. Second, the merchants in each control area are allocated a share of the control area trade benefits based on their change in generation output. That is, the control area trade benefits are allocated to utility-owned generation and merchant generation within the control area based on the absolute value of their change in generation output. Finally, the resulting merchant allocation of trade benefits is further subdivided with the merchants receiving 50 percent of these trade benefits, while native load receives the remaining 50 percent under contractual arrangements. The 50 percent native load share of these trade benefits is allocated on a pro rata basis to all of the participating load in the EIS market. In effect, CRA is using an estimate of the trade benefits allocable to the merchants as a basis for a 50-50 sharing formula between merchants and native load. This is consistent with the 50-50 sharing rule used to allocate trade benefits between control areas discussed above, except that the merchant/utility sharing arrangement would be implemented within a control area. We recognize that this approach provides only a preliminary indication (but a reasonable one, in our view) of how merchant participation might evolve in the future.

4.1.2 Wheeling Impacts

Using the MAPS outputs, wheeling charges and revenues are calculated based on hourly tie-line flows in MAPS multiplied by the applicable wheeling rate. Wheeling charges are paid on "out" transactions, i.e., exports from each control area, and are paid by the load in the importing control area. The wheeling charges are paid to the transmission provider in the exporting control area. These wheeling revenues reduce the net transmission revenue requirement to be paid by the native load in the exporting transmission provider's control area. Since each import is associated with a matching export, wheeling charges and wheeling revenues will match over the entire modeled footprint.

For the transmission owners under the SPP Tariff, wheeling revenues collected by SPP are distributed to individual SPP transmission owners based on a formula that includes MW-mile and other impacts. For purposes of this study, the wheeling revenues calculated using MAPS tie-line flows were redistributed among these transmission owners using each transmission owner's percentage share of 2003 revenue by transmission owner for point-to-point Schedule 7 and 8 external transactions.

4.1.3 Administrative and Operating Costs

A number of costs must be analyzed in addition to those directly addressed in MAPS. These include SPP implementation and operating costs that are ultimately paid by member companies and operating and implementation costs that are incurred directly by member companies.

SPP costs were analyzed using SPP budget forecasts, disaggregated as necessary to identify costs that would change in the Stand-Alone and EIS Market cases. In response to CRA requests, each company provided a projection of the implementation and operating costs it would incur. Individual company responses were compared and discussed in order to ensure a consistent approach among the respondents.

The specific categories of costs addressed in this study are discussed in detail below for each case.

4.2 *Stand-Alone Case Results and Discussion*

4.2.1 Trade Benefits

Implementation of intra-SPP wheeling rates in the Stand-Alone case leads to a less efficient dispatch and thereby yields additional system-wide production costs. Additional production costs for the Eastern Interconnect are $54 million over the study period. Production costs for the transmission owners under the SPP tariff increase by $165 million, while, in contrast, production costs of SPP merchants decrease by $107 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the aggregate Stand-Alone trade impacts for the transmission owners under the SPP tariff are $21 million of lost (i.e., negative) benefits. That is, the Stand-Alone case results in a decrease in trade benefits for the transmission owners under the SPP tariff, and thus an increase in costs. Through the allocation process, transmission owners under the SPP tariff incur 39% ($21/$54) of the total loss in trade benefits across the Eastern Interconnect.

Tables 3, 4 and 5 in Appendix 4-1 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.2.2 Transmission Wheeling Charges

Implementation of intra-SPP wheeling rates leads to significantly greater wheeling charge payments by SPP companies. As noted above, the native load in each control area was assumed to pay the charges associated with the import of power. The wheeling charges increase by $500 million over the study period for the transmission owners under the SPP tariff. Since these are payments, this is a negative benefit to the Stand-Alone case. Table 6 in Appendix 4-1 gives annual wheeling charge increases by company over the study period.

4.2.3 Transmission Wheeling Revenues

Similarly, the implementation of intra-SPP wheeling rates leads to significantly greater wheeling revenue collections by SPP transmission providers. The wheeling revenues are paid to the exporting control area's transmission provider, and then allocated to the native load in that control area. That is, wheeling revenues are used to reduce the transmission revenue requirement for native load. The wheeling revenues for the transmission owners under the SPP tariff increase by $516 million. Since these are revenues, this is a positive benefit to the Stand-Alone case.

As discussed above, the wheeling revenues were calculated using MAPS tie-line flows for the transmission owners under the SPP tariff. The revenues were redistributed among the transmission owners using each transmission owner's percentage share of 2003 revenue for point-to-point Schedule 7 and 8 external transactions. Table 7 in Appendix 4-1 gives annual wheeling revenue increases by company over the study period.

The use of tie-line flows to assess wheeling charges and wheeling revenue impacts when there are loop flows that would not represent actual transactions relies on the presumption that such loop flow impacts will be similar in the Base and alternate cases and thus will not significantly impact the change in wheeling impacts between cases. However, in the case in which there a significant change in wheeling rates between cases, for example the institution of intra-SPP wheeling charges in the Stand-Alone case, the impact of loop flow on intra-SPP tie-line flows has the potential to distort measured wheeling impacts. Given that possibility, the specific company wheeling impacts (both wheeling charges and wheeling revenues) in moving from the Base Case to the Stand-Alone case presented in this study should be viewed as representative results meriting further review and analysis.

4.2.4 Costs to Provide SPP Functions

In addition to its long-running role as a NERC reliability council, SPP performs a number of other reliability/transmission provider functions for transmission-owning members, namely reliability coordination, tariff administration, OASIS administration, available transmission capacity (ATC) and total transmission capacity (TTC) calculations, scheduling agent, and regional transmission planning. Moving to stand-alone status would require the transmission owner to procure these services from an alternative supplier or provide them internally. In turn, however, the transmission owner would avoid payment (through the assessment process) to SPP for SPP's provision of these functions.

Appendix 4-3 provides a discussion of the analysis performed to estimate the differential in costs to provide these functions. That analysis indicates that the transmission owners under the SPP tariff would incur additional costs of $46.0 million over the study period. Since this is an additional cost, this is a negative benefit to the Stand-Alone case.

Some companies would incur a decrease in the net costs for these functions, corresponding to a positive benefit. Table 8 in Appendix 4-1 presents the costs, by company, under the Base and Stand-Alone cases.

Since SPP supplies these functions in both the Base and EIS Market cases, this cost category is not relevant to the comparison of those cases.

4.2.5 FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for SPP RTO member load-serving utilities are assessed directly to SPP when SPP is an RTO (as in the Base and EIS Market cases), and then in turn assessed by SPP to member companies. Under FERC regulations, the annual FERC charge is assessed to all SPP RTO energy for load. This includes the energy transmitted to serve the load of public power companies such as municipals and cooperatives, which would not otherwise be subject to FERC charges. FERC charges for RTO members are therefore significantly higher for investor-owned utilities and are assessed for the first time to publicly owned utilities.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Stand-Alone) basis, there will be higher FERC charges to RTO members than non RTO-members, all else being equal.

For purposes of this study, the impact of the FERC charges between the Base and Stand-Alone cases was estimated by comparing the FERC charges to be assessed to SPP (and then allocated to each SPP member) in 2005 to the average inflation-adjusted FERC charges paid by each individual company in the 1999–2003 period. This impact was then escalated and discounted over the 10-year study period. The 1999–2003 data were used as a source of actual FERC charges paid by SPP member companies when assessed charges on a stand-alone basis. An average over the 1999–2003 period was applied, as the charges vary by year depending on the volume of wholesale transactions. As RTOs continue to form, an increasingly larger share of FERC's total annual charges are being allocated to RTO members than the average over the 1999–2003 period. This approach therefore likely provides a conservative estimate of the savings in FERC charges that would result from stand-alone status in the future. However, it also may overestimate the savings if FERC begins to apply these charges to energy transmitted to native load by utilities that are not part of an RTO and thus puts non-RTO and RTO members on an equal footing.

Using this approach, the decrease in FERC fees under the Stand-Alone case is $47 million for the transmission owners under the SPP tariff over the study period. Since this is a reduction in costs, it is a benefit to the Stand-Alone case. Table 9 in Appendix 4-1 gives the estimated FERC charges, by company, under the Base and Stand-Alone cases.

Since the FERC charges by company would be the same in the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.6 Transmission Construction Costs

Beginning in 2006, SPP will implement a new cost allocation procedure to assign costs for new transmission projects to the transmission owners under the SPP tariff. The existing cost-allocation method directly assigns the cost to the transmission owner in whose control area the project is placed in service. The new cost allocation will use a combination of direct cost assignment, MW-mile impacts, and load ratio shares to assign transmission project capital costs to individual transmission owners under the SPP tariff.

In the Stand-Alone case, the existing direct-assignment cost allocation is assumed to continue. A comparison of the new and existing cost allocation methods was therefore performed to capture the difference in new transmission project revenue requirements for individual companies under the SPP tariff. Only new transmission investment in the 2006–2010 period was considered. Since the total transmission investment is the same in both the Base and Stand-Alone cases, the aggregated impact over all transmission owners under the SPP tariff is zero.[31] For individual company impacts, see Table 10 in Appendix 4-1.

[31] While it is possible that Stand-Alone transmission investment could differ from transmission investment in the Base case, such a difference was not considered in this study. To the extent that transmission providers are

Since the new cost allocation method would be used in both the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.7 Withdrawal Obligations

Moving to stand-alone status would likely require withdrawal from SPP and the payment of an exit fee or withdrawal obligation payment to SPP. The withdrawal obligation for each company was obtained from a recent (July 2004) SPP Finance Committee analysis of this issue. The withdrawal obligation payment is assumed to take place on January 1, 2006. For individual company obligations, see Table 11 in Appendix 4-1.

4.2.8 Total Benefits (Costs)

4.2.8.1 For Transmission Owners under the SPP Tariff

Table 4-1 gives the results by category for the transmission owners under the SPP tariff. The aggregate benefit is ($70.5) million over the study period, i.e., the aggregate benefits of moving to Stand-Alone status are negative. This $70.5 million figure can be thought of as the additional costs incurred by moving to Stand-Alone status.

Table 4-1 Stand-Alone Case Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Table 4-2 gives the total impact of moving to Stand-Alone status for each transmission owner under the SPP tariff. Table 1 in Appendix 4-1 gives results by company and by category. The results in Table 4-2 are shown with and without the impact of wheeling revenues and charges. As shown, excluding wheeling impacts, the benefit of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).

While the aggregate benefit for the transmission owners under the SPP tariff is negative, some individual companies show a moderately positive benefit when wheeling impacts are included. For those companies, the positive result is driven by a significant increase in wheeling revenues when through-and-out wheeling charges to other SPP companies are instituted in the Stand-Alone case. In practice, the increase in wheeling revenues would be associated with a utility that exports significant

affected by the change in cost allocation, network customers of these transmission providers are also be affected.

amounts of power to other SPP companies. Since there are no intra-SPP wheeling charges in the Base case, utilities that export significant amounts of power to other SPP companies would collect considerably more in wheeling revenue in the Stand-Alone case than in the Base case.

However, as discussed above, the change in wheeling rates in the Stand-Alone and the existence of loop flow together result in considerable uncertainty regarding wheeling impacts assessed to individual SPP companies. The collective Stand-Alone impact across SPP is a better measure than the individual company results, as the intra-SPP wheeling charges paid to/from SPP members offset one another in the collective calculation. The individual company Stand-Alone results with wheeling impacts included should therefore be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts.

Table 4-2 Stand-Alone Case Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling	Wheeling Impacts	Total Benefits
AEP	IOU	(19.8)	(3.0)	(22.8)
Empire	IOU	(5.8)	(19.8)	(25.6)
KCPL	IOU	(17.8)	68.7	50.9
OGE	IOU	(8.2)	(10.4)	(18.6)
SPS	IOU	(5.0)	49.5	44.5
Westar Energy	IOU	(17.0)	0.2	(16.9)
Midwest Energy	Coop	(7.9)	3.9	(3.9)
Western Farmers	Coop	1.3	(52.5)	(51.2)
SWPA	Fed	1.2	(20.9)	(19.7)
GRDA	State	(4.8)	(6.0)	(10.8)
Springfield, MO	Muni	(2.5)	6.1	3.5
Total		(86.3)	15.8	(70.5)

4.2.8.2 By State

An allocation by state was carried out for the six IOUs listed in Table 4-2. This was calculated by allocating between wholesale and retail customers using load shares and further dividing the retail customer results by state using load shares.[32] The retail customer results were further divided by state. Table 4-3 gives aggregate retail customer benefits (costs) by state for these six IOUs. Table 1-2 in Appendix 4-1 gives benefits by company by state. To the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

[32] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma, and Southwestern Electric Power Company prior to allocation to individual states.