KANSAS CITY POWER & LIGHT COMPANY AND KCP&L GREATER MISSOURI OPERATIONS COMPANY

INTERIM REPORT IN ACCORDANCE WITH STIPULATION & AGREEMENTS

CASE NOS. EO-2006-0142

AND EO-2009-0179

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INTERIM REPORT REGARDING CONTINUED PARTICIPATION IN SOUTHWEST POWER POOL

SECTION 1: EXECUTIVE SUMMARY

Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO) received approval from the Missouri Public Service Commission (MPSC) to participate in Southwest Power Pool's Regional Transmission Organization in MPSC Case Nos. EO-2006-0142 and EO-2009-0179, respectively. The two dockets were resolved through approval by the MPSC of stipulations with substantively identical provisions for both companies. The stipulations provide for participation in Southwest Power Pool (SPP) during an "Interim Period" that terminates effective October 1, 2013. Two years prior to the termination of this Interim Period, the companies are to "file a pleading accompanied by a study ("Interim Report") comparing the costs and estimated benefits of participation in SPP during a recent twelve-month test period."[1] The stipulation further provides that the companies will "collaborate with the Staff and Public Counsel regarding issues that either party may consider to be critical to a proper cost-benefit analysis."[2] The companies conducted such a collaborative process with the MPSC Staff and Public Counsel in early 2011 and jointly developed an analysis plan for the Interim Report that was agreeable to all three parties. The analysis plan developed in collaboration with Staff and Public Counsel is contained in Attachment A, "RTO Benefit-Cost Analysis Plan". Following is the presentation and discussion of the study resulting from that analysis.

The overall benefit-cost results were developed using a combination of existing benefit-cost studies and new analyses performed by the companies to estimate

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[1] Attachment L: MPSC Case No. EO-2006-0142, Stipulation and Agreement, February 24, 2006, page 3 and Attachment M: MPSC Case No. EO-2009-0179, Stipulation and Agreement, February 27, 2009, page 3.
[2] Attachment L: MPSC Case No. EO-2006-0142, Stipulation and Agreement, February 24, 2006, page 14 and Attachment M: MPSC Case No. EO-2009-0179, Stipulation and Agreement, February 27, 2009, page 13.

and project the net benefits associated with the various Regional Transmission Organization (RTO) service and cost categories. The benefits and costs of functioning within the SPP RTO were compared to those associated with operating KCP&L and GMO on a stand-alone basis without membership in an RTO. The broad categories that were analyzed are the following: reliability services, power markets, transmission facility upgrades, RTO exit fees, and administrative costs. Each of these categories was analyzed in detail as described in Attachment A, with the mid-point results presented below in Table 1 and an estimated range of outcomes presented in Table 2. These tables show the net benefits (costs) associated with the companies operating in SPP as compared to operating on a stand-alone basis. To the extent feasible, the results were framed as the average annual net benefit for the period from 2014 to 2017, inclusive. The 2017 time horizon is consistent with the analysis plan agreed to by the parties and 2014 is the first calendar year subsequent to the termination of the current Interim Period. Additionally, 2014 is the year in which SPP plans to implement its enhanced power markets.

Table 1: Average Annual Benefits - 2014 -2017

Benefits (Costs) ($ Thousands)	Mid Estimate		
Company	**KCP&L**	**GMO**	**Total**
Reliability Services	$ 794	$ 436	$ 1,229
Power Market Operations	$ 28,100	$ 18,002	$ 46,102
Transmission Upgrades	$ (18,611)	$ (12,136)	$ (30,747)
RTO Exit Fees	$ 1,399	$ 799	$ 2,198
Administrative Costs	$ (5,353)	$ (2,938)	$ (8,292)
TOTAL	**$ 6,328**	**$ 4,162**	**$ 10,490**
Additional Factors			
-Cost Allocation Review	$ 2,545	$ 1,115	$ 3,660
-Impact on Wholesale Transactions	$ 6,168	$ 2,468	$ 8,636
ADJUSTED TOTAL	**$ 15,041**	**$ 7,745**	**$ 22,786**

The mid-point results shown in Table 1 represent the average of the range of cases presented in Table 2. For the two companies together, the projected annual net benefits of participating in SPP vary from approximately $(4) million in the low case to $50 million in the high case, yielding a mid-point net benefit of about $23 million per year. These results include elements that were not identified in the original analysis plan but were anticipated with a provision for factors that have impacts which are more difficult to assess. These factors include the potential for future transmission facility cost allocation adjustments by SPP and the negative power market impacts of non-firm transmission service, higher transmission rates, price risk, and transaction costs associated with the RTO boundary. Even when these elements are removed from the study totals, the projected annual net benefits of SPP participation for the two companies range from approximately $(4) million in the low case to $25 million in the high case, yielding a mid-point net benefit of $10 million per year.

Sections 2 through 7 of this report address each of the analysis categories and describe the sources and calculation methodologies that produced the results shown in Tables 1 and 2. A summary table with the disaggregated results underlying Tables 1 and 2 is presented in Attachment B.

Table 2: Range of Average Annual Benefits 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate		
Company	**KCP&L**	**GMO**	**Total**	**KCP&L**	**GMO**	**Total**
Reliability Services	$ 794	$ 436	$ 1,229	$ 794	$ 436	$ 1,229
Power Market Operations	$ 20,754	$ 13,443	$ 34,197	$ 35,446	$ 22,560	$ 58,007
Transmission Upgrades	$ (18,611)	$ (12,136)	$ (30,747)	$ (18,611)	$ (12,136)	$ (30,747)
RTO Exit Fees	$ 1,399	$ 799	$ 2,198	$ 1,399	$ 799	$ 2,198
Administrative Costs	$ (7,124)	$ (3,870)	$ (10,995)	$ (3,582)	$ (2,007)	$ (5,589)
TOTAL	**$ (2,790)**	**$ (1,328)**	**$ (4,118)**	**$ 15,446**	**$ 9,652**	**$ 25,098**
Additional Factors						
-Cost Allocation Review	$ -	$ -	$ -	$ 5,090	$ 2,230	$ 7,320
-Impact on Wholesale Transactions	$ -	$ -	$ -	$ 12,336	$ 4,935	$ 17,271
ADJUSTED TOTAL	**$ (2,790)**	**$ (1,328)**	**$ (4,118)**	**$ 32,872**	**$ 16,818**	**$ 49,689**

SECTION 2: RELIABILITY SERVICES ANALYSIS

For purposes of this report, Reliability Services consist of reliability coordination and reserve sharing services. The estimated value of reliability coordination services is taken from existing studies of these services and supplemented with KCP&L and GMO specific information. For reserve sharing services, the incremental cost in the stand-alone case reflects the cost of transmission service necessary for reserve sharing support plus an annual fee assessed by SPP for external participants in the reserve sharing group.

A fundamental service SPP provides is regional reliability coordination service to its members resulting in the minimization of disturbances, system events and outages on the bulk electric system. SPP estimates that these reliability services reduce and avoid between $185 million and $280 million per year for the SPP footprint.[3] For KCP&L and GMO to provide similar services in a coordinated, regional approach would require additional personnel and computer systems in order to effectively plan and operate the bulk electric system with sufficient reliability. The requirements for KCP&L and GMO to provide these in the stand alone case are additional costs of approximately $1.1 million per year[4]. These values are detailed in Table 3: Stand-Alone Reliability Coordination Service.

Table 3: Stand-Alone Reliability Coordination Service

Costs	2014	2015	2016	2017	Average
KCP&L	$ 676,600	$ 694,300	$ 711,000	$ 728,700	$ 702,650
GMO	$ 356,900	$ 366,200	$ 375,000	$ 384,300	$ 370,600
Total	$ 1,033,500	$ 1,060,500	$ 1,086,000	$ 1,113,000	$ 1,073,250

The estimated annual cost of transmission service for KCP&L and GMO reserve sharing support is $42,900 and $17,000, respectively. These estimates result from the actual monthly average reserve sharing MWh, purchased from January 2009 through June 2011, times the current SPP non-firm point-to-point transmission rates from the SPP OASIS. The SPP point-to point rates were adjusted for projected increases in base plan funding over the study period for energy delivered to KCP&L and GMO. See Attachments E, F, G, H and I for supporting details. In addition, Associated Electric Cooperative, Inc. currently

[3] Attachment C: Southwest Power Pool Filing, MPSC Docket EO-2011-0134, In the Matter of and Investigation into Southwest Power Pool Cost Allocations and Cost Overruns, December 29, 2010, page 18.

[4] Figures for Reliability Coordination Service provided from Attachment D, CRA International, RTO Cost-Benefit Analysis, Aquila Missouri Electric Utility Operations, March 28, 2007, pages 40-42. Figures for KCP&L and GMO combined are estimated to be 50% higher than values provided in the CRA report. Company specific costs based on load ratio share split between KCP&L and GMO.

pays a $4,000/month fee as an external participant in the SPP reserve sharing group. Thus, it is assumed that KCP&L and GMO would each incur $48,000 annually to be an external participant. These reserve sharing costs are shown on the Reserve Sharing line of Attachment B.

A summary of the Reliability Services Analysis results is provided in Table 4.

Table 4: Reliability Service Average Annual Benefits 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Reliability Services									
-Reliability Coordination	$ 703	$ 371	$ 1,073	$ 703	$ 371	$ 1,073	$ 703	$ 371	$ 1,073
-Reserve Sharing	$ 91	$ 65	$ 156	$ 91	$ 65	$ 156	$ 91	$ 65	$ 156
Subtotal	**$ 794**	**$ 436**	**$ 1,229**	**$ 794**	**$ 436**	**$ 1,229**	**$ 794**	**$ 436**	**$ 1,229**

SECTION 3: POWER MARKET OPERATIONS

For the power markets analysis, existing studies were utilized to a large extent as detailed in the following sections.

3.1 ENERGY IMBALANCE SERVICE MARKET STUDIES

There are two different analyses that looked at the Energy Imbalance Service (EIS) market specifically—the study that was performed by Charles River Associates (CRA) prior to market start and a study that was completed by SPP and Boston Pacific after the first year of market operations. The CRA study produced more detailed results. For example, it included GMO (Aquila) in a special set of scenarios and it produced results for individual market participants. The post-implementation study by SPP and Boston Pacific excluded GMO and produced results on an SPP regional basis only. This study has the advantage of being of more recent vintage and being tied to actual market results.

The gas prices underlying these two studies are somewhat different—prices in the later study were about 20 percent higher than the earlier study. These two studies are referenced to create an estimated range of benefits associated with the EIS market.

On July 27, 2005, CRA provided a study of the EIS Market for SPP. A copy of this study is Attachment J of this report. This study looked at three cases: SPP in its 2005 form with no EIS market, implementation of an EIS market in the SPP transmission tariff footprint, and a stand-alone case with no EIS market and abandonment of the SPP transmission tariff. CRA concluded that the net benefit of the EIS Market for all SPP participants would be $614 million over the 10-year study period.[5] A summary of the KCP&L and Missouri specific ten-year present value results[6] of the study are detailed in Table 5: Specific Benefits - CRA 2005 Study.

Table 5: Specific Benefits - CRA 2005 Study

Entitiy	Benefit - $ Million
KCP&L	$ (2.20)
Missouri	$ 41.70

As Table 5 details, KCP&L showed a small net increase in costs when full costs and benefits are allocated over the entire system. However, these results include the costs of implementing and administering the EIS market, which are not pertinent to the 2014-2017 study period for this report because SPP is to be implementing day-ahead and ancillary service markets in 2014. When EIS market implementation and administration costs are excluded from the CRA 2005 study results, KCP&L shows an annual net benefit of $2.157 million during the study period. This value is utilized in the overall benefits and cost summary as shown in the low case on the Energy Imbalance Service line of Attachment B.

The study included a sensitivity case which quantified the effect of including Aquila (GMO) in the SPP EIS Market. The sensitivity only looked at the additional generation cost or benefit resulting from Aquila joining SPP[7]. A summary of the Aquila (GMO portion only) annual generation cost savings is detailed in Table 6:

[5] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page IX.
[6] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page XI.
[7] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page XVII.

Generation Cost Savings - Aquila Sensitivity. This value is utilized in the overall benefits and cost summary as shown in the low case on the Energy Imbalance Service line of Attachment B.

Table 6: Generation Cost Savings - Aquila Sensitivity

Entitiy	Gen Cost Savings - $ Millions	
Aquila	$	0.30

The study conducted by Boston Pacific was documented in the Market Monitoring Unit and External Market Advisor Report to the SPP Board of Directors/Members Committee, presented on April 22, 2008. The Market Monitoring Unit report is included with this document as Attachment K. Boston Pacific's study was based on empirical data and calculated a $103 million[8] annual benefit from the EIS market operation. Company allocations of benefits were estimated by applying a peak demand weighting factor on total SPP estimated benefits.

Table 7: Boston Pacific Study Results

Entity	Annual Benefit ($M)	
SPP total	$	103.00
KCP&L allocation	$	8.55
GMO allocation	$	4.51

The KCP&L allocation value above is utilized in the overall benefits and cost summary as shown on the Energy Imbalance Service line of Attachment B.

3.2 COMPANY STUDY OF ENERGY IMBALANCE SERVICE MARKET

The Stipulation and Agreements for MPSC Case Nos. EO-2006-0142 and EO-2009-0179 ("Stipulations") require each company to file pleadings and reports documenting the benefits of participation in the SPP EIS Market for KCP&L and GMO individually. Both Stipulations are included with this document as Attachment L and Attachment M, respectively. The company study covered the

[8] Attachment K: Southwest Power Pool, Inc., Market Monitoring Unit and External Market Advisor, Report to SPP Board of Directors/Members Committee, April 22, 2008, Executive Summary.

scope detailed in the Stipulations by looking at a recent 12-month period defined as calendar year 2010.

3.2.1 SCOPE OF COMPANY STUDY

The Stipulations clearly define the nature of the pleading and report that the company should file. Quoting the GMO Stipulation:

> Two (2) years prior to the conclusion of the Interim Period, KCP&L-GMO shall file a pleading accompanied by a study ("Interim Report") comparing the costs and estimated benefits of participation in SPP during a recent twelve-month test period. As described in Section II.D, the pleading shall address the merits of KCP&L-GMO's continued participation in SPP.[9]

3.2.1.1 INTERIM REPORT – BENEFIT/COST ANALYSIS

The Stipulation for each company further describes the Interim Report that is to accompany the final pleading in the footnotes. Quoting Footnote 2 of the GMO agreement:

> What is contemplated in this Interim Report is that the actual (modeled) production costs for KCP&L-GMO participating in the SPP facilitated markets will be compared to an estimate of what those costs would have been absent such participation for a twelve-month period. This Interim Report does not anticipate a SPP-wide cost/benefit study.[10]

The Stipulations for KCP&L and GMO both use this language to describe the Interim Report and the scope of the benefit/cost analysis.

3.2.1.2 SCOPE OF COMPANY BENEFIT/COST ANALYSIS

The reports for each company include the following features:

1) The benefit/cost analysis was conducted using production cost modeling runs to estimate the total cost of operation for each system. The test period

[9] Attachment M: MPSC Case No. EO-2009-0179, Stipulation and Agreement, February 27, 2009, page 3.
[10] Attachment M: MPSC Case No. EO-2009-0179, Stipulation and Agreement, February 27, 2009, page 3.

of the model is the 2010 calendar year to meet the requirement that the report cover a recent twelve month period. Normal budget assumptions are used to simulate actual operating parameters while actual fuel prices were used to calculate current costs. The analysis consisted of two separate scenarios. The comparison of these scenarios highlight the benefit of market participation through reduced production costs. Each company, KCP&L and GMO, have an individual set of scenarios and a separate analysis.

a. Scenario 1: Current Operation: Simulation of the company fleet using actual fuel prices and interchange budget assumptions, which includes participation in the existing SPP EIS market.

b. Scenario 2: Operation without the EIS Market: Simulation of the company fleet using identical fuel prices and interchange budget assumptions from Scenario 1 with two exceptions to approximate operation outside the EIS market.

- SPP Transmission Effect: In the previously referenced CRA July 2005 SPP Cost-Benefit Analysis, a scenario was developed to simulate the effect of removing SPP transmission operation by reducing flowgate capacity by 10%.[11] For purposes of this report, the model applied a reduction in transmission import and export capability of 10% for sales to and from the SPP Market to simulate reduced flowgate capacity.

- Wheeling Impact: The CRA report further identified the effect of wheeling charges with a scenario that applied a wheeling charge to power flows within the SPP footprint. CRA defined wheeling rates

[11] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page 3-3.

for each modeled interface as a wheel-out rate.[12] For purposes of this report, a wheeling charge was applied to power being sold by the company to the wholesale market. The value of this wheeling rate was determined from the KCP&L and GMO zonal components of the actual transmission cost data provided in Attachments H and I. The rates used in the simulation are detailed in Table 8: Wheeling Rates.

Table 8: Wheeling Rates

Fees - $/MWhr	GMO Off-Peak	GMO On-Peak	KCP&L Off-Peak	KCP&L On-Peak
Zonal Non-Firm	$ 2.200	$ 4.630	$ 1.160	$ 2.450
Schedule Fee	$ 0.015	$ 0.015	$ 0.029	$ 0.029
Reactive Voltage	$ 0.002	$ 0.002	$ 0.001	$ 0.001
Base Plan Regional Non-Firm	$ 0.137	$ 0.289	$ 0.137	$ 0.289
Base Plan Zonal Non-Firm	$ 0.064	$ 0.134	$ 0.118	$ 0.249
Total	$ 2.418	$ 5.070	$ 1.445	$ 3.018

3.2.2 DESCRIPTION OF MIDAS MODEL

For the company analysis, the MIDAS™ model from ABB-Ventyx was utilized. The MIDAS™ model provided hourly chronological dispatch of all system generating assets including unit commitment logic that simulated the actual operation of utility system resources. The model contained all unit operating variables required to simulate the units. These variables include but are not limited to heat rates, fuel costs, variable operation and maintenance costs, sulfur dioxide emission allowance costs, scheduled maintenance outages, forced and derate outage rates, each on a unit-by-unit basis.

The model also simulated market transactions using actual performance from 2010 as a baseline. For this study, the company has limited the ability to purchase and sell market power in the non-EIS market scenario by 10% to a level consistent with CRA's modeling assumptions.

[12] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page 3-2.

3.2.3 RESULTS OF COMPANY STUDY

Summary data from the KCP&L production cost study is included in Table 9: KCP&L Production Cost Summary. This study estimates that the net benefit from participating in the EIS market for KCP&L in 2010 was $6,653,349. The detailed summary of this study is included as Attachment N to this document .

Table 9: KCP&L Production Cost Summary

MWHrs	EIS Market	No EIS	Change
Total Generation Supply - MWHrs	21,998,770	21,897,335	-0.46%
Total Market Purchases - MWHrs	827,227	750,999	-9.21%
Total Market Sales - MWHrs	6,235,316	6,107,237	-2.05%
Dollars	**EIS Market**	**No EIS**	**Change**
Total Generation Supply - $	$ 261,985,000	$ 261,502,000	-0.18%
Total Market Purchases - $	$ 29,762,204	$ 28,999,103	-2.56%
Total Market Sales - $	$ 183,316,181	$ 175,416,732	-4.31%
Adjusted Production Cost - $	$ 108,431,023	$ 115,084,372	6.14%
Net Increase		**$ 6,653,349**	

Summary data for the GMO production cost study is included in Table 10: GMO Production Cost Summary. This study estimates that the net benefit from participating in the EIS market for GMO in 2010 was $6,210,503. The detailed summary of this study is included as Attachment O to this document.

Table 10: GMO Production Cost Summary

MWHrs	EIS Market	No EIS	Change
Total Generation Supply - MWHrs	6,425,847	6,424,749	-0.02%
Total Market Purchases - MWHrs	3,183,230	3,060,937	-3.84%
Total Market Sales - MWHrs	558,399	435,014	-22.10%
Dollars	**EIS Market**	**No EIS**	**Change**
Total Generation Supply - $	$ 117,268,000	$ 118,341,000	0.91%
Total Market Purchases - $	$ 83,319,495	$ 84,393,335	1.29%
Total Market Sales - $	$ 16,233,405	$ 12,169,742	-25.03%
Adjusted Production Cost - $	$ 184,354,090	$ 190,564,593	3.37%
Net Increase		**$ 6,210,503**	

Total adjusted production cost impact for both companies is summarized in Table 11: Adjusted Production Cost Summary.

Table 11: Adjusted Production Cost Summary

Adjusted Production Cost - $	EIS Market
KCP&L	(6,653,349)
GMO	(6,210,503)
Total Great Plains Energy	(12,863,852)

The GMO value above is utilized in the overall benefits and cost summary as shown on the Energy Imbalance Service line of Attachment B.

3.3 FUTURE MARKETS STUDY BY VENTYX

The day-ahead and ancillary service market impacts for all companies in the region were analyzed in a study for SPP by Ventyx. This study, titled *Southwest Power Pool, Cost Benefit Study for Future Market Design, Final Report*, was issued on April 7, 2009 and is included with this document as Attachment P. The base case in this study assumes the current EIS market, with the change cases looking at different combinations and timing of day-ahead and ancillary service markets. Change Case IIA, with the start date moved to 2014, is the most appropriate scenario to use for this report because it corresponds to SPP's current plans for future markets. The Ventyx study results are available for both KCP&L and GMO. The Ventyx market benefits can be added to those resulting from the EIS market studies detailed in Sections 3.1 and 3.2 of this document to create an estimate of the total benefits related to the future markets planned by SPP compared to a stand-alone case.

The Ventyx study looked at several scenarios of future markets. The annual net benefits of Case IIA from the report[13] are summarized as Table 12: Ventyx Study - Case IIA Summary.

[13] Attachment P: Ventyx, Southwest Power Pool, Cost Benefit Study for Future Market Design, Final Report, April 7, 2009, page 62.

Table 12: Ventyx Study - Case IIA Summary

Gross Benefits ($M)	SPP Subtotal	Unallocated Congestion	SPP Gross	KCP&L	GMO
2014	$ 209.00	$ (73.00)	$ 136.00	$ 24.00	$ 2.00
2015	$ 201.00	$ (64.00)	$ 137.00	$ 26.00	$ 5.00
2016	$ 232.00	$ (79.00)	$ 153.00	$ 24.00	$ 4.00
Average 2014-2016	**$ 214.00**	**$ (72.00)**	**$ 142.00**	**$ 24.67**	**$ 3.67**
Average After Unallocated Congestion				**$ 16.37**	**$ 2.43**

The gross benefit values for both companies and SPP (based on Table 4-13 of the Ventyx study) are shown in the table above. The average gross benefit for KCP&L is utilized in the overall benefits and cost summary as shown on the Future Markets line of Attachment B. Also, the KCP&L and GMO values reduced by a prorated share of unallocated congestion from Table 4-13 of the Ventyx study are shown on the Future Markets line of Attachment B.

3.4 CRA STUDY FOR GMO

In 2007, CRA International (CRA) performed a GMO-specific study that included the benefits of a real-time market with security-constrained economic dispatch. This essentially captures the benefits of the EIS market. In addition, this CRA study included the benefits of other market structures, such as a day-ahead market with unit commitment, which SPP is planning to implement in 2014. This study is referenced to provide another estimate of the benefits for GMO attributable to the upcoming SPP markets. CRA produced this report titled *RTO Cost-Benefit Analysis, Aquila Missouri Electric Utility Operations* on March 28, 2007. It is included with this document as Attachment D.

The study compared the total benefit of Aquila joining either MISO or SPP compared to a stand-alone case. The final results of this study[14] are summarized in Table 13: CRA Aquila Study Summary.

[14] Attachment D: CRA International, RTO Cost-Benefit Analysis, Aquila Missouri Electric Operations, March 28, 2007, page 39.

Table 13: CRA Aquila Study Summary

GMO in SPP RTO ($M)	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Production Cost Savings	673.4	80.2	85.0	90.0	95.2	100.7	105.9	111.4	117.1	123.0	129.1
Purchase Cost Savings	(465.5)	(49.4)	(53.3)	(57.3)	(61.5)	(65.8)	(73.1)	(80.7)	(88.7)	(97.0)	(105.7)
Sales Revenue Increases	(112.2)	(16.1)	(16.7)	(17.4)	(18.0)	(18.7)	(17.8)	(16.8)	(15.8)	(14.7)	(13.6)
Subtotal Trade Benefits	95.7	14.7	15.0	15.3	15.7	16.2	15.0	13.9	12.6	11.3	9.8
Savings Trans/Rel Functions	16.0	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
RTO Administrative Charges	(23.5)	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
Additional FERC Charges	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Subtotal Other Charges	(8.8)	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.5)	(1.5)
Total	**86.9**	**13.4**	**13.8**	**14.1**	**14.4**	**14.9**	**13.7**	**12.5**	**11.2**	**9.8**	**8.3**

To develop the value of the future market, the value of the EIS market from Section 3.2.2 for GMO is subtracted from the average of the Trade Benefits for 2014 through 2017. This value is presented below in Table 14 below.

Table 14: Value of the Future Market - GMO

Market	Benefit $M
Average Trade Benefits 2014-2017	$ 11.85
EIS Market Benefit	$ 6.21
Future Market Value	$ 5.64

The Future Market Value benefit for GMO given in the table above is utilized in the overall benefits and cost summary as shown on the Future Markets line of Attachment B.

3.5 CONSOLIDATED BALANCING AUTHORITY

The SPP consolidated balancing authority has the potential to reduce costs as compared to the current framework of individual balancing authority areas. In 2008, the SPP Consolidated Balancing Authority Steering Committee developed[15] estimates of this potential cost savings as summarized in Table 15: Consolidated Balancing Authority Savings. The savings largely result from a reduced workforce level required by individual balancing authorities and reduced regulation for load requirements. The Steering Committee Executive Summary is included with this document as Attachment Q . Although the Steering Committee only reported results through 2012, savings to 2017 have been estimated by escalating costs by

[15] Attachment Q: Southwest Power Pool CBA Steering Committee, Consolidated Balancing Authority Project, Executive Summary, 2008, pages 6-8.

2.5% annually for additional years and are shown on the Balancing Authority Consolidation line of Attachment B.

Table 15: Consolidated Balancing Authority Savings

Annual Benefit	2010	2011	2012	2013	2014	2015	2016	2017	Average 2014-2017
Consolidated BA operating costs plus depreciation	$1,487,000	$1,523,000	$1,561,075	$1,600,102	$1,640,104	$1,681,107	$1,723,135	$1,766,213	$1,702,640
KCP&L Share (8.3013%)	123,440	126,429	129,590	132,829	136,150	139,554	143,043	146,619	141,341
GMOC Share (4.3786%)	65,110	66,686	68,353	70,062	71,814	73,609	75,449	77,335	74,552
Savings in Reduced FTEs/BA	$ 330,078	$ 330,078	$ 338,330	$ 346,788	$ 355,458	$ 364,344	$ 373,453	$ 382,789	$ 369,011
KCP&L Share (50% of 1 BA)	165,039	165,039	169,165	173,394	177,729	182,172	186,726	191,395	184,506
GMOC Share (50% of 1 BA)	165,039	165,039	169,165	173,394	177,729	182,172	186,726	191,395	184,506
Reduced Regulation for Load	$6,188,000	$6,188,000	$6,188,000	$6,188,000	$6,188,000	$6,188,000	$6,188,000	$6,188,000	$6,188,000
KCP&L Share (8.3013%)	513,684	513,684	513,684	513,684	513,684	513,684	513,684	513,684	513,684
GMOC Share (4.3786%)	270,948	270,948	270,948	270,948	270,948	270,948	270,948	270,948	270,948
Net Benefits of CBA	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Average 2014-2017**
KCP&L Share	**$ 555,283**	**$ 552,295**	**$ 553,260**	**$ 554,249**	**$ 555,263**	**$ 556,303**	**$ 557,368**	**$ 558,460**	**$ 556,849**
GMOC Share	**$ 370,877**	**$ 369,301**	**$ 371,760**	**$ 374,280**	**$ 376,863**	**$ 379,511**	**$ 382,225**	**$ 385,007**	**$ 380,902**

3.6 ADDITIONAL CONSIDERATIONS

In addition to the existing market operations studies, other factors as discussed below need to be incorporated in order to provide a valid comparison between the SPP case and the stand-alone case:

3.6.1 COST TO IMPLEMENT FUTURE MARKETS

Current capital cost estimates of $9.3 million[16] for both internal company and external vendor costs to implement the SPP Future Markets and the consolidated balancing authority will be added to the cost side of the SPP case. These estimated costs reflect internal and contract labor, market software license fees, hardware costs, and deal management and optimization site licenses. Amortized over a seven-year period, the costs equal approximately $1.3 million per year during the study period. A detailed examination of implementation costs for the SPP Future Markets is included with this document as Attachment R. These costs do not reflect approximately $0.8 million capital costs for interfaces to manage other RTO transactions such as MISO and PJM. Furthermore, an additional $0.5

[16] Attachment R: Capital Budget Estimate - Implementation SPP Integrated Marketplace, 2011.

million in capital costs will be needed to interface with SPP markets if KCP&L and GMO are stand-alone entities. The on-going expenses associated with new market systems and approximately six new full-time positions are $1.6 million in 2014 and $1.9 million/year for 2015-2017. Total estimated costs to implement integrated markets are shown on the Internal Market Operations line of Attachment B.

3.6.2 INCREMENTAL TRANSMISSION CHARGES FOR EXISTING RESOURCES DUE TO STAND-ALONE OPERATION

Stand-alone operations would involve significant incremental transmission charges because of the need to cross tariff boundaries for the purpose of importing power to and exporting power from the KCP&L and GMO transmission systems.

Current estimated incremental annual costs of point-to-point transmission service to deliver energy from existing network resources to load are reflected in Table 16 below and on the Transmission Service-Existing Resources line of Attachment B. These estimates result from the actual MW value of reserved firm transmission service for existing network resources outside the KCP&L and GMO transmission systems times the current SPP firm point-to-point transmission rates from the SPP OASIS as adjusted for projected increases in base plan charges over the study period for energy delivered to KCP&L and GMOC, respectively. Supporting details for these values are provided in Attachment S.

Table 16: Transmission Service for Existing Resources

Company	2014	2015	2016	2017	Average
KCP&L	$ 3,247,942	$ 3,901,665	$ 3,770,543	$ 3,841,488	$ 3,690,410
GMO	$ 10,777,057	$ 12,125,682	$ 11,344,414	$ 11,328,016	$ 11,393,792

The cost of transmission upgrades associated with existing confirmed transmission reservations would be paid through the point-to-point transmission rates over the anticipated life of the reservations.

3.7 POWER MARKET OPERATIONS SUMMARY

A summary of the Power Market Operations results is provided in Table 17.

Table 17: Power Market Operations Average Annual Benefits – 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Power Market Operations									
-Energy Imbalance Service	$ 2,157	$ 300	$ 2,457	$ 8,550	$ 6,211	$ 14,761	$ 5,353	$ 3,255	$ 8,609
-Future Markets	$ 16,368	$ 2,433	$ 18,801	$ 24,667	$ 5,639	$ 30,306	$ 20,517	$ 4,036	$ 24,553
-Consolidated Balancing Authority	$ 557	$ 381	$ 938	$ 557	$ 381	$ 938	$ 557	$ 381	$ 938
-Cost to Implement Future Market	$ (2,018)	$ (1,064)	$ (3,082)	$ (2,018)	$ (1,064)	$ (3,082)	$ (2,018)	$ (1,064)	$ (3,082)
-Trans. Charges for Existing Gen	$ 3,690	$ 11,394	$ 15,084	$ 3,690	$ 11,394	$ 15,084	$ 3,690	$ 11,394	$ 15,084
Subtotal	**$ 20,754**	**$ 13,443**	**$ 34,197**	**$ 35,446**	**$ 22,560**	**$ 58,007**	**$ 28,100**	**$ 18,002**	**$ 46,102**

SECTION 4: TRANSMISSION FACILITY UPGRADE ANALYSIS

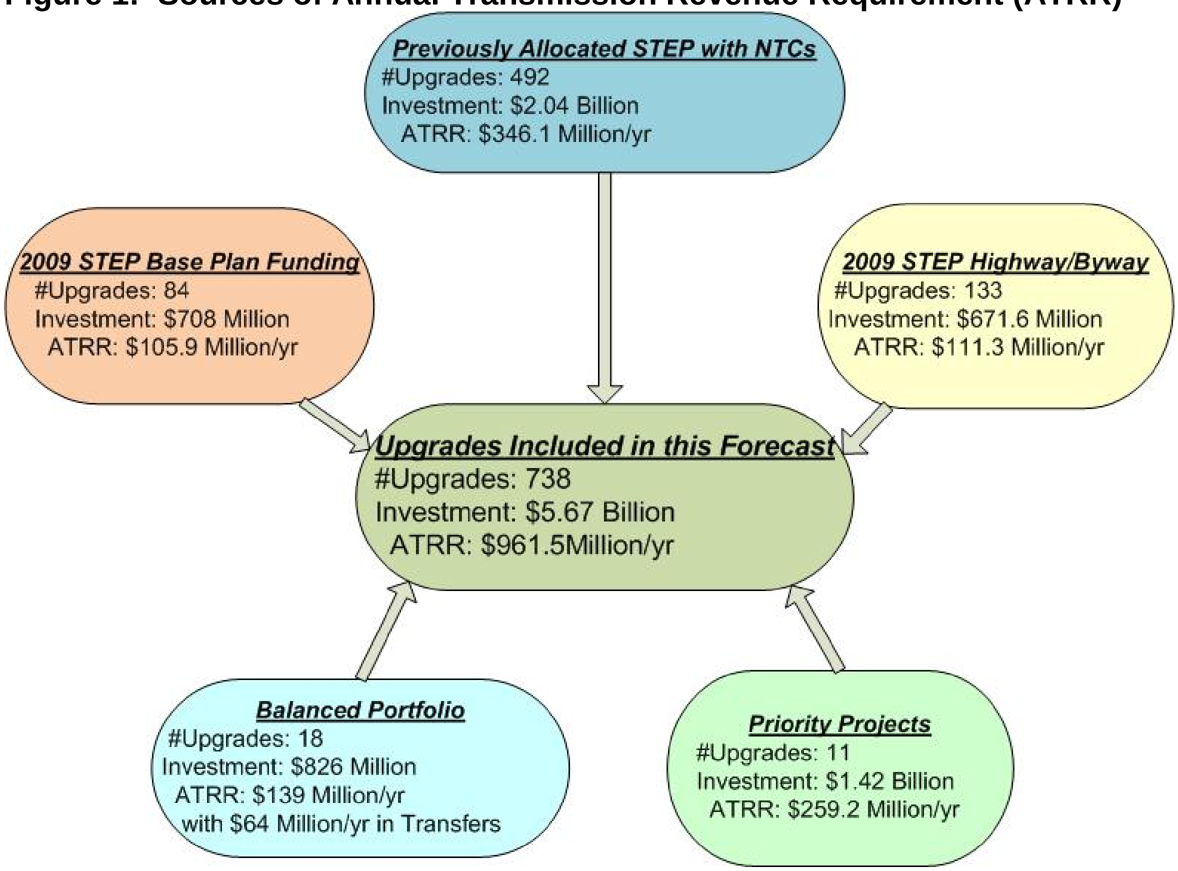
4.1 BENEFIT AND COST OF SPP PROJECTS

The work performed by the Regional State Committee's Rate Impact Task Force (RITF) serves as a key component of this analysis because it reflects projected costs of projects in the 2010 SPP Transmission Expansion Plan (SPP Board approved in early 2011). Also identified are the resulting benefits of select project sets including the Balanced Portfolio and Priority Project sets.

As the Transmission Provider for the region, SPP is required to meet specific transmission service obligations and transmission planning functions. Transmission solutions for transmission service and generation interconnection requests are developed in order to effectively deliver various capacity and energy resources to load centers. Reliability upgrades are identified and planned within a robust transmission planning process in order to meet North American Electric Reliability Corporation (NERC) reliability standards for bulk electric system stability and ultimately end-use customer reliability. In addition, due to emerging market development, SPP has developed economic-based project sets that improve the region's generation and trade benefits, reduce grid congestion, deliver large-scale renewable generation such as wind power, and enable regional generation resource futures.

The resulting transmission obligations are apportioned to members according to specified provisions within SPP's FERC-approved transmission tariff. Some transmission upgrades have primarily zonal reliability benefits and are therefore cost allocated to that zone. Others transmission projects provide a wide set of regional benefits for which the costs are shared among all members in the region. The resulting set of annual transmission revenue requirements (ATRR) assessed to members is therefore a combination of these plans and cost allocations. Figure 1 is a representative example from the recent RITF work indicating the sources of ATRR that fund these transmission obligations.[17]

Figure 1: Sources of Annual Transmission Revenue Requirement (ATRR)



KCP&L and GMO obtain a wide array of benefits from these transmission infrastructure additions: grid reliability, production and trade benefits, renewable integration, and delivery of generation to load centers. While not all reliability

[17] SPP Rate Impact Task Force Materials – January 10, 2011 Presentation, Slide 9.

projects and additions for transmission service have quantifiable benefits, the economic-based project sets have defined and quantified benefits to the members and region. For SPP's Balanced Portfolio and Priority Projects combined project sets, SPP estimates the benefits are $480 million per year for the SPP footprint.[18]

Annual benefits to KCP&L and GMO for the Balanced Portfolio and Priority Project sets for the 2014 to 2017 study period were derived from existing SPP project development analysis work with additional annualized calculations applied as shown in Attachment B. KCP&L and GMO have taken a conservative approach for the inclusion of these project set benefits. As an example, gas price impacts, originally included in the Priority Project benefit totals, are excluded from the benefit calculations for KCP&L and GMO.

Attachment V indicates the ATRR obligations for each SPP member which includes those projects after regional cost allocation and base plan funding were implemented. These are shown in the upper set of figures labeled as "Legacy Tariff Not Included with CWIP" and represent those forecasted transmission obligations in ATRR values from years since regional funding was instituted in 2006. They exclude those original "legacy" transmission obligations related to each member's original zonal network transmission assets. Please refer to Attachment V Projected ATRR for details.

Table 18 below summarizes the individual and total forecasted SPP transmission obligations of KCP&L and GMO in ATRR for the years 2014 to 2017.

Table 18: Forecasted SPP Transmission Obligations

SPP Projected ATRR	2014	2015	2016	2017	Avg 2014-17
KCP&L Transmission Obligations	$42,326,335	$37,272,889	$36,940,031	$46,096,858	$40,659,028
GMO Transmission Obligations	$19,755,494	$15,920,198	$14,561,956	$19,435,879	$17,418,382
Total	$62,081,829	$53,193,087	$51,501,987	$65,532,737	$58,077,410

[18] See Attachment BB: Southwest Power Pool Filing, MPSC Docket EO-2011-0134, In the Matter of and Investigation into Southwest Power Pool Cost Allocations and Cost Overruns, December 29, 2010, page 19.

4.2 COST OF STAND-ALONE OPERATION

The companies developed projections of the transmission service costs that would be incurred as a result of operating stand-alone. The stand-alone requirements are driven primarily by the need to provide reliable transmission service to KCP&L and GMO customers under NERC and Regional Entity standards and to meet state-mandated renewable energy standards.

KCP&L's and GMO's projected capacity additions for renewable resources from wind are expected to increase by an additional 283 MW and 100 MW, respectively, by 2017. The wind resources are assumed to be remotely located from the KCP&L and GMO service territories, most likely in western Kansas. To obtain reliable transmission service for delivery of these remote renewable resources, KCP&L and GMO would purchase firm point-to-point transmission service from the SPP OASIS as adjusted for projected increases in base plan charges over the study period for energy delivered to KCP&L and GMOC, respectively. These costs are shown below in Table 19 for KCP&L and Table 20 for GMO.

Table 19: KCP&L Transmission Costs for Additional Renewable Resources

Year	TS MW	TS $/MW-yr	Trans. Service	Base Plan Charges	Admin. Fees	Total
2014	131	$ 10,176	$ 1,333,056	$ 1,163,332	$ 324,759	$2,821,147
2015	183	$ 10,176	$ 1,862,208	$ 2,428,006	$ 453,672	$4,743,886
2016	283	$ 10,176	$ 2,879,808	$ 3,364,435	$ 701,580	$6,945,823
2017	283	$ 10,176	$ 2,879,808	$ 3,499,181	$ 701,580	$7,080,569
Average			**$ 2,238,720**	**$ 2,613,739**	**$ 545,398**	**$5,397,856**

Table 20: GMO Transmission Costs for Additional Renewable Resources

Year	TS MW	TS $/MW-yr	Trans. Service	Base Plan Charges	Admin. Fees	Total
2014	100	$ 19,248	$ 1,924,800	$ 803,399	$ 247,908	$2,976,107
2015	100	$ 19,248	$ 1,924,800	$ 1,178,017	$ 247,908	$3,350,725
2016	100	$ 19,248	$ 1,924,800	$ 960,998	$ 247,908	$3,133,706
2017	100	$ 19,248	$ 1,924,800	$ 956,443	$ 247,908	$3,129,151
Average			**$ 1,924,800**	**$ 974,714**	**$ 247,908**	**$3,147,422**

4.3 TRANSMISSION FACILITY UPGRADE SUMMARY

A summary of the Transmission Facility Upgrade results are provided in Table 21 below.

Table 21: Transmission Upgrade Average Annual Benefit – 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Transmission Facility Upgrade									
-Benefit of SPP Projects	$ 16,650	$ 2,135	$ 18,785	$ 16,650	$ 2,135	$ 18,785	$ 16,650	$ 2,135	$ 18,785
-Cost of SPP Projects	$ (40,660)	$ (17,418)	$ (58,078)	$ (40,660)	$ (17,418)	$ (58,078)	$ (40,660)	$ (17,418)	$ (58,078)
-Cost of Stand-Alone Operation	$ 5,398	$ 3,147	$ 8,545	$ 5,398	$ 3,147	$ 8,545	$ 5,398	$ 3,147	$ 8,545
Subtotal	**$ (18,611)**	**$ (12,136)**	**$ (30,747)**	**$ (18,611)**	**$ (12,136)**	**$ (30,747)**	**$ (18,611)**	**$ (12,136)**	**$ (30,747)**

SECTION 5: SPP EXIT FEES ANALYSIS

For the stand-alone case, an estimate of potential exit fees is necessary. It is expected that the framework for such fees will soon be modified as a result of SPP stakeholder discussions now addressing this issue.

Withdrawal obligations to SPP are based on existing transmission tariff and membership provisions that address facilities, systems and financial commitments necessary to maintain and implement transmission and energy market services to members. The total SPP financial obligation and the portion of estimated withdrawal obligations attributable to KCP&L and GMO are represented in Figure 2. The basis for the estimate are a withdrawal date of October 1, 2013 and allocation based on the 2010 KCP&L, GMO and total SPP Net Energy for Load values.

In order to address projects that have been assigned by SPP to KCP&L and GMO for construction, the conditions for exiting SPP would also carry the potential for either joint operating agreements for those facilities or the cancellation of projects such as the Iatan-Nashua 345kV line and the Sibley-Nebraska City 345kV line. While these projects provide significant regional benefits, SPP would be obligated to seek equitable treatment for remaining members should KCP&L and GMO no longer participate in SPP.

Figure 2: Estimated SPP Exit Fees

Southwest Power Pool

Approximate Member Withdrawal Obligations

as of 10/1/2013

8.7.2 Computation of a Member's Existing Obligations

For purposes of computing the Existing Obligations of any withdrawing or terminated Member in accordance with the Membership Agreement, such "Member's share" is a percentage calculated as follows:

$$A = 100\ [0.25(2/N) + 0.75(B/C)]$$

Where: A = Member's share (expressed as a percentage)
N = Total number of Members
B = The Member's previous year Net Energy for Load within SPP
C = Total of factor B for all Members

Factors

N = 63 Members

B = KCPL's NEL is approximately 24,065,395

C = SPP's NEL is approximately 213,375,531

Therefore

A = 100 [0.25(2/63) + 0.75(24,065,395 / 213,375,531)]

A = 9.2525%

Southwest Power Pool Long-Term Obligations

Office Lease Commitment	$980,543
Office Equipment Lease Commitment	$8,584
2027 Mortgage Note (Principal)	$3,803,600
2027 Mortgage Note (Interest Rate Swap, FMV as of 11/1/10*)	$2,387,751
2014 (5.65%) Senior Notes (Principal)	$6,875,000
2014 (5.65%) Senior Notes (Interest Rate Swap, FMV as of 11/1/10*)	$1,101,592
2016 (5.45%) Senior Notes (Principal)	$16,500,000
2016 (5.45%) Senior Notes (Make Whole Provision)	$0
2010A & 2010B New Facility Notes (Principal)	$64,259,032
2010A New Facility Note (Make Whole Provision)	$100,855
2010B New Facility Note (Make Whole Provision)	$117,665
2010C Future Markets Note (Principal)	$70,000,000
2010C Future Markets Note (Make Whole Provision)	$0
Contractual Commitments	$170,635
Total Long-Term Obligations (As of 10/1/2013)	**$166,305,258**
Member's Share	**9.2525%**
KCPL's Withdrawal Obligation	**$15,387,394**

* Fair market values must be updated at time of withdrawal to determine actual member's share. Fair market values as of 11/1/10 used for estimation purposes.

Table 22: Total Company Estimated SPP Exit Fees

Company	Net Energy for Load-MWh	NEL Share	Withdrawal Obligation
KCP&L	15,626,676	5.89%	$ 9,794,548
GMO	8,438,719	3.36%	$ 5,592,846
Total	24,065,395	9.25%	$ 15,387,394

The withdrawal obligations for each company are assumed to be expensed using seven-year straight line depreciation. These values are included in the overall benefits and cost summary on the RTO Exit Fee line of Attachment B.

A summary of the Estimated Exit Fees is provided in Table 23.

Table 23: SPP Exit Fee Annual Average Benefit 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
SPP Exit Fees	$ 1,399	$ 799	$ 2,198	$ 1,399	$ 799	$ 2,198	$ 1,399	$ 799	$ 2,198

SECTION 6: ADMINISTRATIVE COSTS ANALYSIS

On a stand-alone basis, KCP&L and GMO would be required to provide additional administrative functions for tariff administration, OASIS administration, transmission capacity calculations, transmission billing and settlements, scheduling agent, and regional transmission planning. These services are currently provided within SPP and relate to specific requirements and obligations that would be necessary for KCP&L and GMO to maintain and operate as a stand-alone transmission provider.

KCP&L and GMO estimate that these administrative costs will range between the estimates provided in the CRA Cost Benefit Study for GMO (Aquila)[19] and the estimates contained in CRA's 2005 study as shown in Attachment J. In both cases, the total number for KCP&L and GMO together is assumed to be fifty percent higher than the cost estimated for a single company. The administrative cost estimates obtained from these two studies are shown in Tables 19 and 20.

[19]Attachment D: CRA International, RTO Cost-Benefit Analysis, Aquila Missouri Electric Operations, March 28, 2007

If KCP&L and GMO move from SPP to stand-alone status, a reduction in cost may result from FERC policy regarding assessment of its administrative costs. Current FERC policy assesses these costs against all load that has been placed under the control of an RTO, whereas stand-alone companies are assessed only on the basis of wholesale transactions. FERC has considered the possibility of modifying this policy, which would remove this disincentive to RTO participation. Company projections of the annual difference in assessment that can result from this policy are $1.15 million for KCP&L and $0.60 million for GMO. These are included as negative values in the low case on the Administrative Costs line in Attachment B. They are not included in the high case because of the possibility that FERC will modify this policy before or during the 2014-17 projection period.

One aspect that is not quantified in these estimates is the potential for KCP&L and GMO to be required, as a condition for leaving the RTO, to engage a third party to conduct various administrative and planning functions to fulfill its obligations as a stand-alone transmission provider. The scope and cost for such an arrangement would be highly speculative at this point. However, other companies that have utilized such third party services are believed to have incurred annual costs on the order of magnitude of $10 to $20 million.

Table 24: Administrative Costs Based on the Study for Aquila

Stand-Alone Administrative Costs	2014	2015	2016	2017
Tariff Administration - GMO	$125,000	$128,000	$131,000	$134,000
OASIS Administration - GMO	$412,000	$422,000	$432,000	$443,000
ATC/TTC Calculations - GMO	$125,000	$128,000	$131,000	$134,000
Scheduling Agent - GMO	$414,000	$424,000	$435,000	$445,000
Transmission Planning - GMO	$125,000	$128,000	$131,000	$134,000
Total - GMO	**$1,201,000**	**$1,230,000**	**$1,260,000**	**$1,290,000**
Adjustment for Second Company(50%)	$600,500	$615,000	$630,000	$645,000
Total - GPE	**$1,801,500**	**$1,845,000**	**$1,890,000**	**$1,935,000**

The 2005 CRA study estimated administrative costs for KCP&L in Appendix 4-3, Table 2[20], which shows the KCPL projected annual stand-alone administrative

[20] Attachment J: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, page AII-29.

costs with a 10-year present value of $24,661,000. The average annual value for 2014 and 2015 was utilized for this study and incremented by fifty percent to reflect operations for two companies.

Table 25: Administrative Costs - 2005 CRA Study

Costs ($ Thousands)	10-Year NPV	Annualized
KCP&L	$ 24,661	$ 4,395
Adjustment for Second Company (50%)	$ 12,331	$ 2,198
Total - GPE	**$ 36,992**	**$ 6,593**

The value above is utilized in the overall benefits and cost summary as shown on the Administrative Costs line of Attachment B.

A summary of the Administrative Costs Analysis is provided in Table 26 below.

Table 26: Administrative Costs Average Annual Benefit – 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Administrative Costs	$ (7,124)	$ (3,870)	$ (10,995)	$ (3,582)	$ (2,007)	$ (5,589)	$ (5,353)	$ (2,938)	$ (8,292)

SECTION 7: ADDITIONAL FACTORS

There are other factors that have a bearing on the benefits and costs of RTO participation that were not specifically addressed in the analysis plan for this study. Factors not readily quantifiable were provided for in the final section of the analysis plan with the statement that "they will be identified as additional considerations with an indication of the potential impact and direction in which the results likely would be affected." Such elements identified by the companies include the potential for future cost responsibility to be shifted in order to balance project costs and benefits under the SPP tariff and the potential impacts of stand-alone operation on wholesale market transactions that were not fully captured in the studies discussed in Section 3. Although projecting the effects of these elements presents additional challenges, the potential impacts are very substantial and should be considered in evaluating the overall benefit-cost results, as discussed in Sections 7.1 and 7.2 below.

7.1 COST ALLOCATION REVIEW

In order to mitigate the risk that SPP members could obtain future benefits insufficient to offset the costs of installed transmission projects, SPP has established specific tariff provisions in order to address such potential effects. These tariff provisions are being implemented through the Regional Allocation Review Task Force (RARTF) – a group composed of state commission representatives from the Regional State Committee and member representatives from the Markets and Operations Policy Committee. The scope and objective of these efforts is to develop the analytical methodology that will be used as a basis for any necessary forward-looking adjustments to cost allocations or project sets in order to minimize or eliminate inequitable cost-benefit effects on members. SPP expects the RARTF to complete this work by year-end 2011 so that the resulting proposals can be filed with the FERC during the first quarter of 2012. KCP&L and GMO expect that these provisions and the resulting cost-benefit adjustments will provide significant protections in connection with ongoing SPP membership cost allocations.

Obviously, the impact of such future policy changes and resulting adjustments cannot be determined at this time. However, a potential effect could be the implementation of adjustments to make whole those parties that have a negative net benefit resulting from the Priority Projects. Based upon the 2009 Priority Projects analysis, KCP&L has a negative net benefit present value of $65.6 million and GMO has negative net benefit present value of $28.8 million, both calculated for a 40-year projection and excluding the gas price impacts identified in the study. These negative benefits could be offset on a present value basis if KCP&L were to receive an annual transfer or annual incremental benefits of $5.1 million and GMO were to receive an annual transfer or annual incremental benefits of $2.2 million over the 40 year period. Such transfers or benefits could be effected through future cost allocation provisions or decisions regarding future project selection. In presenting the summary results, these illustrative transfer impacts are shown in the high case, with no transfers shown in the low case.

7.2 IMPACT ON WHOLESALE TRANSACTIONS

Transmission service priority, transaction costs, price risk, and point-to-point transmission rates all have material impacts on market operations. Each of these will have a negative effect on KCP&L and GMO if the companies operate on a stand-alone basis rather than in the SPP footprint.

With regard to service priority, potential counterparties are less likely to enter into transactions with KCP&L and GMO when the transmission path crosses a tariff boundary because of the inability to secure a path that is as firm as what could be obtained if transacting with another party in the RTO footprint. The loss of potential counterparties due to increased risk of curtailments could materially impact the operating cost of the companies. It is difficult to calculate the potential curtailments that might be incurred as a stand-alone entity because few market participants currently utilize lower priority non-firm point-to-point service for wholesale transactions. The companies anticipate the increased use of non-firm point-to-point transmission service associated with stand-alone operations will result in an increased level of schedule curtailments, which may result in a 10 – 15% impact on off-system sales volumes.

Another factor influencing the level of counterparty transactions across an RTO boundary is the cost and ease with which transactions in the same RTO can be conducted, as compared to transactions with an external entity. This consideration of transaction cost pushes market participants toward sales and purchases that do not cross an RTO boundary.

A third factor is price risk associated with external transactions, which typically cannot be hedged as easily as transactions within the RTO footprint. In the day-ahead energy market under development by SPP, the price risk within the market can be managed through Transmission Congestion Rights, but price risk on transactions with external entities cannot be fully addressed in that manner.

A final element that impedes external transactions is the rate “pancaking” effect resulting from the assessment of point-to-point charges on one or both legs of the transmission path across an RTO border. Table 27 shows the point-to-point rates projected for the 2014-2017 period for the KCP&L and GMO transmission pricing zones. As can be seen, they are significantly higher than the 2010 wheeling rates that were used for the company study discussed in Section 3.2. These 2014-2017 projections serve as estimates of the rates that will be paid by an external entity to import power from SPP during that time period. Although the same numbers do not necessarily serve as projections of the wheeling rates for power exported from KCP&L and GMO as entities external to SPP, including these rates in simulation of such power sales does recognize the effect of inefficiencies associated with the other factors described above (i.e., lower priority transmission service, transaction costs, and price risk).

Table 27: Wheeling Rates - Transmission Priority Sensitivity.

Fees - $/MWhr	GMO Off-Peak	GMO On-Peak	KCP&L Off-Peak	KCP&L On-Peak
Zonal Non-Firm	$ 2.200	$ 4.630	$ 1.160	$ 2.450
Schedule Fee	$ 0.015	$ 0.015	$ 0.029	$ 0.029
Reactive Voltage	$ 0.002	$ 0.002	$ 0.001	$ 0.001
Base Plan Funding	$ 1.110	$ 2.340	$ 1.320	$ 2.790
Admin Fee	$ 0.283	$ 0.283	$ 0.283	$ 0.283
Total	**$ 3.610**	**$ 7.270**	**$ 2.793**	**$ 5.553**
Total Used in Company Study	$ 2.418	$ 5.070	$ 1.445	$ 3.018
Delta	$ 1.192	$ 2.200	$ 1.348	$ 2.535

In order to recognize these effects on system costs, the wheeling rates in Table 27 were applied in the same simulation model that was used to produce the results discussed under Section 3.2. The results of this simulation were a $6.2 million increase in KCP&L net system cost, as shown in Table 28, and a $2.5 million increase in GMO net system cost, as shown in Table 29. For GMO, the risk of losing access to the RTO market is less than the risk for KCP&L. This is due to the fact that GMO’s coal fleet is more committed to serving native load energy needs, with less available for wholesale. Detailed results of these simulations are provided in Attachment T and U for KCP&L and GMO, respectively.

Table 28: KCP&L Additional Wheeling Charge Impact on APC

MWHrs	No EIS	Additional Risk	Change
Total Generation Supply - MWHrs	21,897,335	21,818,743	-0.36%
Total Market Purchases - MWHrs	750,999	710,645	-5.37%
Total Market Sales - MWHrs	6,107,237	5,988,291	-1.95%
Dollars	**No EIS**	**Additional Risk**	**Change**
Total Generation Supply - $	$ 261,502,000	$ 260,643,000	-0.33%
Total Market Purchases - $	$ 28,999,103	$ 29,038,309	0.14%
Total Market Sales - $	$ 175,416,732	$ 168,428,936	-3.98%
Adjusted Production Cost - $	$ 115,084,372	$ 121,252,373	5.36%
Net Increase		**$ 6,168,001**	
Delta from EIS Market - Sect. 3.2		$ 6,653,349	
Net Increase from EIS Market		**$ 12,821,350**	

Table 29: GMO Additional Wheeling Charge Impact on APC

MWHrs	No EIS	Additional Risk	Change
Total Generation Supply - MWHrs	6,424,749	6,407,255	-0.27%
Total Market Purchases - MWHrs	3,060,937	3,021,047	-1.30%
Total Market Sales - MWHrs	435,014	377,631	-13.19%
Dollars	**No EIS**	**Additional Risk**	**Change**
Total Generation Supply - $	$ 118,341,000	$ 118,114,000	-0.19%
Total Market Purchases - $	$ 84,393,335	$ 85,258,850	1.03%
Total Market Sales - $	$ 12,169,742	$ 10,340,666	-15.03%
Adjusted Production Cost - $	$ 190,564,593	$ 193,032,184	1.29%
Net Increase		**$ 2,467,591**	
Delta from EIS Market - Sect. 3.2		$ 6,210,503	
Net Increase from EIS Market		**$ 8,678,094**	

The KCP&L and GMO Net Increase values are utilized in the overall benefits and cost summary as shown on the Impact on Wholesale Transactions line of Attachment B.

A set of stochastic simulations was run to estimate the amount of variability associated with the results shown in Table 28 and Table 29. Not surprisingly, there is tremendous variation in simulation results due to uncertainty in factors such as fuel prices and unit availability, with each company's adjusted production costs varying more than $100 million between the lowest and highest cases. The distributions of adjusted production costs had mean standard errors ($14.7 million for KCP&L and $5.1 million for GMO) that were more than double the estimated changes in net system cost resulting from the increase in wheeling rates shown above. With the Net Increase amounts shown in Tables 28 and 29 serving as a base case, the wide dispersion of stochastic simulations permits the low case to be set at zero impact. Although it is improbable that the effect of these factors actually would be zero, this value allows the low estimate on the Adjusted Total line in Table 2 to reflect only those factors specifically mentioned in the analysis plan. Assuming a symmetric distribution, the high case is set at twice the estimated Net Increase amounts, with a $12.3 million impact on KCP&L and a $4.9 million impact on GMO.

It is likely that the distribution of these wholesale transaction impacts is not symmetric and that the effect on the companies' adjusted production costs can be substantially greater than the high case discussed above. However, it was not feasible to quantify such effects with any certainty. Historically, member companies see a significant reduction in bilateral wholesale transactions with entities outside the RTO footprint. For example, KCP&L experienced a substantial decrease in transactions with parties in the MISO footprint after start-up of the MISO market. Similarly, a large company within MISO has reported that its wholesale transactions outside the RTO footprint nearly ceased when it joined the MISO market. Thus, external entities have less opportunity for sales and purchases than those inside an RTO, with consequent effects on those external companies' adjusted production costs.

7.3 ADDITIONAL FACTOR SUMMARY

A summary of the Additional Factor Analysis is provided in Table 30 below.

Table 30: Additional Factor Average Annual Benefit - 2014-2017

Benefits (Costs) ($ Thousands)	Low Estimate			High Estimate			Mid-Point		
Company	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Additional Factors									
-Cost Allocation Review	$ -	$ -	$ -	$ 5,090	$ 2,230	$ 7,320	$ 2,545	$ 1,115	$ 3,660
-Impact on Wholesale Transactions	$ -	$ -	$ -	$ 12,336	$ 4,935	$ 17,271	$ 6,168	$ 2,468	$ 8,636
Subtotal	$ -	$ -	$ -	$ 17,426	$ 7,165	$ 24,591	$ 8,713	$ 3,583	$ 12,296

Benefit-Cost Analysis of Kansas City Power & Light and KCP&L GMO Participation in Southwest Power Pool

Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO) plan to implement the following alternative approach in order to address the requirements of the current SPP membership stipulations (Case Nos. EO-2006-0142 and EO-2009-0179) and suggestions from the Missouri Public Service Commission Staff and Office of Public Council:

1) Develop a wider scope of benefit-cost analysis beyond the stipulated Energy Imbalance Service (EIS) market analysis of a historical year.
2) Utilize a value proposition approach in structuring the analysis to include a full spectrum of elements with a bearing on the benefits and costs of Regional Transmission Organization participation.
3) Control the cost to perform the analysis by utilizing existing studies where available and developing estimates internally for the remaining components of the analysis.

As described in greater detail below, this alternative method not only broadens the analysis but also avoids the unnecessary expense of hiring a third party consultant to perform studies that already exist. In addition, it allows the use of information specific to KCP&L and GMO where helpful and practical.

The following are elements that would be needed in this analysis in order for KCP&L and GMO to estimate benefits and costs of SPP membership:

<u>Reliability Services</u>
Reliability Coordination
Reserve Sharing

<u>Energy Markets</u>
Energy Imbalance Service Operational Benefits and Costs
Day-Ahead and Ancillary Services Operational Benefits and Costs
Balancing Authority Consolidation
Market Operation Costs—Both Internal and External
Incremental Impact of Transmission Charges
Incremental Impact of Lower Priority Transmission Service on Power Transactions

<u>Transmission Upgrades</u>
Benefits of Transmission Upgrades
Costs of Transmission Upgrades

<u>SPP Exit Fees</u>
Additional Cost Applicable to the Stand-Alone Case

Administrative Costs
Transmission Planning
Tariff Administration and FERC Regulatory Services
Scheduling, Dispatch, and System Control
FERC and NERC Compliance
Settlements

Each of these elements will be analyzed for both an SPP membership case and a stand-alone operations case. The net benefits and costs of these elements then will be summed for the SPP case and for the stand-alone case in order to create a total value comparison. Where practical, it will be helpful to attach ranges to these valuations in order to reflect the reality of significant uncertainty behind the estimates. The time horizon of the study will extend until 2016 or 2017, which is long enough to capture the expected completion of projects with currently issued Notifications to Construct.

Reliability Services Analysis
The estimated value of reliability coordination services can be taken from existing studies of these services and supplemented with KCP&L and GMO specific information if appropriate. In the case of reserve sharing services, the incremental cost in the stand-alone case likely will be only the cost of transmission service necessary for reserve sharing support.

Energy Markets Analysis
For the energy markets analysis, existing studies can be utilized to a large extent. There are two different analyses that looked at the EIS market specifically—the study that was performed by CRA International prior to market start and a study that was completed by SPP and Boston Pacific after the first year of market operations. The CRA study was a more thorough analysis and produced more detailed results. For example, it included GMO (Aquila) in a special set of scenarios and it produced results for individual market participants. Although the post-implementation study excluded GMO and produced results on a regional basis only, it has the advantage of more recent vintage and being tied to actual market results. In addition, the gas prices underlying the two studies are somewhat different—prices in the later study were about 20 percent higher than the earlier study. These two studies will be referenced in a complementary fashion, perhaps to create an estimated range of benefits associated with the EIS market. In addition, an analysis will be conducted by the Company to estimate system production costs both with and without the EIS market. This study will cover the scope detailed in the Stipulation and Agreement by looking at a recent 12-month period.

The day-ahead and ancillary service market impacts for all companies in the region were analyzed in a 2009 Ventyx study. The base case in this study is the EIS market, with the change cases looking at different combinations and timing of day-ahead and ancillary service markets. Change Case IIA, with the start date moved to 2014, is the most appropriate scenario to use because it corresponds to SPP's current plans for future markets. This study's results may be supplemented in the near future with analysis to quantify the potential impact of gas price changes. The Ventyx study results are available for both KCP&L and GMO. The Ventyx market benefits can be added to those resulting from the EIS studies mentioned above to create an estimate of the total benefits related to the future markets planned by SPP.

There also is a GMO-specific study performed by CRA in 2007 that includes the benefits of a real-time market with security-constrained economic dispatch. This essentially captures the benefits of the EIS market. In addition, this CRA study includes the benefits of other market structures, such as a day-ahead market with unit commitment, which SPP is planning to implement in 2014. This study will be referenced in a complementary manner to provide another estimate of the benefits for GMO attributable to the upcoming SPP markets.

The consolidated balancing authority has the potential to reduce costs as compared to the current framework of individual balancing authority areas. SPP has developed estimates of this potential cost savings, which is available for inclusion in the analysis.

In addition to the existing market operations studies, other factors need to be incorporated in order to provide a valid comparison between the SPP case and the stand-alone case:
1) Current estimates of both internal and external costs to implement the SPP day-ahead and ancillary service markets and the consolidated balancing authority will be added to the cost side of the SPP case. Potentially offsetting a portion of those new market costs, the stand-alone case may entail additional administrative costs to manage interfaces between the companies and multiple RTO markets.
2) Stand-alone operations would involve significant incremental transmission charges because of the need to cross tariff boundaries for the purpose of importing power to and exporting power from the KCP&L and GMO transmission systems. These costs will be added to the stand-alone case to the extent they are not already incorporated in the EIS study.
3) Transmission service priority can have a material impact on market operations. Potential counterparties are less likely to enter into transactions with KCP&L and GMO when the transmission path crosses a tariff boundary because of the inability to secure a path that is as firm as they could obtain if transacting with another party in the SPP footprint. This impact will be added to the stand-alone case and may require some additional study with the MIDAS model.

<u>Transmission Upgrades Analysis</u>
The work performed by the Regional State Committee’s Rate Impact Task Force (RITF) can serve as a key component of this analysis because it reflects projected costs of projects in the 2010 SPP Transmission Expansion Plan (SPP Board approved in early 2011). It also reflects the benefits of such projects, but only to the extent those benefits have been quantified by SPP studies (i.e., only Balanced Portfolio and Priority Project benefits).

Corresponding projections will be needed for a stand-alone case in order to compare to the SPP case represented by the RITF estimates. This will involve developing projections of the transmission upgrades and transmission service charges that would be incurred as a result of operating stand-alone. The stand-alone requirements would be driven primarily by the need to provide reliable transmission service to KCP&L and GMO customers under NERC and Regional Entity standards and to meet state-mandated renewable energy standards. However, economic upgrades also may be considered in the stand-alone scenario.

An uncertainty in this area is whether and how cost impacts may be shifted or mitigated as a result of the provisions in the SPP Tariff, Attachment J, Section III.D (entitled "Review of Base Plan Allocation Methodology"). This element may be documented as a non-quantified factor in the analysis.

<u>SPP Exit Fees Analysis</u>
For the stand-alone case, an estimate of potential exit fees will be necessary. It is expected that the framework for such fees will soon be clarified by the SPP stakeholder discussions now addressing this issue. The cost assumptions underlying this component should be consistent with those in other sections of this study, such as cost assumption regarding transmission upgrades.

<u>Administrative Costs Analysis</u>
Projections of the fees under SPP Schedule 1-A (excluding the day-ahead and ancillary service market components) will be compared to estimates of the costs that will be incurred by KCP&L and GMO if they have to provide their own transmission planning, tariff administration, scheduling and system control, compliance work, and transmission settlements as a stand-alone entity. In developing these projections, estimates utilized in other proceedings will be reviewed, such as those in the SPP study by CRA, those in the GMO (Aquila) study by CRA, and estimates included in AmerenUE's recent Missouri dockets addressing RTO participation.

<u>Factors Not Explicitly Quantified</u>
Not all factors that have a bearing on the benefits and costs of RTO participation may be readily quantifiable. Where such factors are identified but not included in the numeric analysis, they will be identified as additional considerations with an indication of the potential impact and direction in which the results likely would be affected.

Average Annual Benefits (Costs) to Kansas City Power & Light and KCP&L Greater Missouri Operations from Participation in Southwest Power Pool in Comparison to Stand-Alone Status, 2014-2017
($ Thousands)

	Low Estimate			High Estimate			Mid-Point		
	KCP&L	GMO	Total	KCP&L	GMO	Total	KCP&L	GMO	Total
Reliability Services									
Reliability Coordination	$ 703	$ 371	$ 1,073	$ 703	$ 371	$ 1,073	$ 703	$ 371	$ 1,073
Reserve Sharing	$ 91	$ 65	$ 156	$ 91	$ 65	$ 156	$ 91	$ 65	$ 156
Subtotal	$ 794	$ 436	$ 1,229	$ 794	$ 436	$ 1,229	$ 794	$ 436	$ 1,229
Power Market Operations									
Energy Imbalance Service	$ 2,157	$ 300	$ 2,457	$ 8,550	$ 6,211	$ 14,761	$ 5,353	$ 3,255	$ 8,609
Future Markets	$ 16,368	$ 2,433	$ 18,801	$ 24,667	$ 5,639	$ 30,306	$ 20,517	$ 4,036	$ 24,553
Consolidated Balancing Authority	$ 557	$ 381	$ 938	$ 557	$ 381	$ 938	$ 557	$ 381	$ 938
Cost to Implement Future Markets	$ (2,018)	$ (1,064)	$ (3,082)	$ (2,018)	$ (1,064)	$ (3,082)	$ (2,018)	$ (1,064)	$ (3,082)
Trans. Charges for Existing Resources	$ 3,690	$ 11,394	$ 15,084	$ 3,690	$ 11,394	$ 15,084	$ 3,690	$ 11,394	$ 15,084
Subtotal	$ 20,754	$ 13,443	$ 34,197	$ 35,446	$ 22,560	$ 58,007	$ 28,100	$ 18,002	$ 46,102
Transmission Facility Upgrades									
Benefit of SPP Projects	$ 16,650	$ 2,135	$ 18,785	$ 16,650	$ 2,135	$ 18,785	$ 16,650	$ 2,135	$ 18,785
Cost of SPP Projects	$ (40,660)	$ (17,418)	$ (58,078)	$ (40,660)	$ (17,418)	$ (58,078)	$ (40,660)	$ (17,418)	$ (58,078)
Cost of Stand-Alone Operation	$ 5,398	$ 3,147	$ 8,545	$ 5,398	$ 3,147	$ 8,545	$ 5,398	$ 3,147	$ 8,545
Subtotal	$ (18,611)	$ (12,136)	$ (30,747)	$ (18,611)	$ (12,136)	$ (30,747)	$ (18,611)	$ (12,136)	$ (30,747)
SPP Exit Fees	$ 1,399	$ 799	$ 2,198	$ 1,399	$ 799	$ 2,198	$ 1,399	$ 799	$ 2,198
Administrative Costs	$ (7,124)	$ (3,870)	$ (10,995)	$ (3,582)	$ (2,007)	$ (5,589)	$ (5,353)	$ (2,938)	$ (8,292)
SUBTOTAL	$ (2,790)	$ (1,328)	$ (4,118)	$ 15,446	$ 9,652	$ 25,098	$ 6,328	$ 4,162	$ 10,490
Additional Factors									
Cost Allocation Review	$ -	$ -	$ -	$ 5,090	$ 2,230	$ 7,320	$ 2,545	$ 1,115	$ 3,660
Impact on Wholesale Transactions	$ -	$ -	$ -	$ 12,336	$ 4,935	$ 17,271	$ 6,168	$ 2,468	$ 8,636
Subtotal	$ -	$ -	$ -	$ 17,426	$ 7,165	$ 24,591	$ 8,713	$ 3,583	$ 12,296
TOTAL	$ (2,790)	$ (1,328)	$ (4,118)	$ 32,872	$ 16,818	$ 49,689	$ 15,041	$ 7,745	$ 22,786

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of and Investigation into	)	
Southwest Power Pool Cost Allocations and	)	File No. EO-2011-0134
Cost Overruns	)	

SOUTHWEST POWER POOL, INC.'S COMMENTS IN RESPONSE TO THE COMMISSION'S ORDER OPENING AN INVESTIGATION INTO SOUTHWEST POWER POOL COST ALLOCATIONS AND COST OVERRUNS

COMES NOW, Southwest Power Pool, Inc. ("SPP"), by and through its counsel, and hereby submits its Comments in response to the Public Service Commission of the State of Missouri's ("Commission") Order Opening An Investigation into Southwest Power Pool Cost Allocations and Cost Overruns ("Order") issued on November 23, 2010, opening the above-styled docket.

Southwest Power Pool is a Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 61 members in nine states and serves more than 6 million households in a 370,000 square-mile area. SPP's members include 14 investor-owned utilities, 9 municipal systems, 12 generation and transmission cooperatives, 4 state agencies, 7 independent power producers, 10 power marketers and 5 independent transmission companies. As an RTO, SPP is a transmission provider currently administering Transmission Service over 48,874 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.

SPP desires to respond to the Commission in a helpful manner and provide information to address the issues raised by the Commission. In the Order, the Commission expressed concern about recent developments involving SPP and the selection and funding of large dollar amount interstate electric transmission projects and the costs that will be borne by the Missouri ratepayers of Kansas City Power & Light Company ("KCP&L"), KCP&L Greater Missouri Operations Company ("KCP&L-GMO"), and The Empire District Electric Company ("Empire"), all of which are members and transmission service customers of SPP. In response to this Order, and in an effort to assist the Commission in its investigation, SPP will provide further information and clarification on the development of procedures for addressing cost estimation, cost variances and novations, as well as the overall value of SPP, benefits realized by Empire and the implications of withdrawal.

I. Background and Overview

The Commission's Order directs investigation into several issues related to SPP's transmission planning processes and cost allocation procedures. The Order sets forth specific questions and concerns regarding the processes used to select, fund and assign cost responsibility for new transmission projects within the SPP footprint.

As part of the ordered investigation, the Commission notes the need for closer examination of the cost-benefit analyses used by SPP in selecting the "Priority Projects" and, specifically, the weight/value properly accorded to a project's "qualitative" benefits. The Commission emphasizes the importance of ensuring "...that Missouri customers are not inappropriately subsidizing economic benefits to other SPP customers," and orders the development of a report detailing the "costs and benefits of SPP membership for The Empire District Electric Company." The Commission cites to the recent cost estimate increases for the Priority Project in raising questions concerning the reliability of SPP's cost-estimation analyses and, among other inquiries, invites consideration of whether a novation – i.e., the procedure by which a Transmission Owner is permitted to transfer construction rights and all legal and financial obligations to a third party – may be contributing to project cost estimate increases.

The primary purpose of these comments is to document the steps being taken by SPP to address the issues raised in the Commission's Order. As detailed herein, many of these very issues are currently being considered by SPP's Strategic Planning Committee ("SPC") and Transmission Working Group ("TWG") in response to recommendations submitted by the Regional State Committee ("RSC") to the SPP Board of Directors ("SPP Board").[1] The recommendations, which followed a lengthy discussion regarding recent project cost estimate increases and possible refinements to current cost estimation and planning procedures, provide as follows:

> MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
>
> MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011.
>
> MOTION 3: RSC recommends that SPP consider establishing design and construction standards for transmission projects at 200KV and above that are regionally funded.
>
> MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.[2]

The framing of the RSC motions reflects a clear commonality of issues between ongoing SPP initiatives and the Commission's recently opened investigation. It is therefore appropriate that the Commission proceed with its investigation in coordination with SPP's concurrent examination of the same core issues. In that regard, the Commission is advised that, on December 3, 2010, SPP staff presented whitepapers to the SPC setting forth preliminary

[1] The RSC adopted the motions on October 25, 2010. On October 26, 2010, the SPP Board of Directors approved the motions and assigned to the SPC and TWG responsibility for consideration of the issues raised in the RSC motions.

[2] The RSC also adopted a fifth motion, which was addressed to the Cost Allocation Working Group ("CAWG") and provides as follows: "Motion 5: Move that the CAWG study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to the RSC." The CAWG is in the process of developing a response.

responses to the RSC recommendations.[3] Further development of the steps outlined in these whitepapers will necessarily entail consideration of the project-estimation, funding and cost-benefit matters raised in the Commission's Order. Moreover, to the extent these efforts result in more rigorous cost estimation protocols, changes in the treatment of cost variances, or overall improvements to the planning process, the evaluation of RTO membership benefits, both generally and in the specific context of Empire, could be materially affected.

SPP, including staff, stakeholders, committees, and working groups, is committing significant resources to addressing the RSC recommendations. While these efforts are in their early stages with any procedural and/or policy changes ultimately subject to SPP's stakeholder review process, they are being pursued on a high-priority basis. The issues implicated by the RSC recommendations bear directly on the questions posed in the Commission's order. Accordingly, SPP urges that the Commission conduct its investigation in an open and coordinated fashion, mindful that the ongoing efforts within the SPP stakeholder process may helpfully inform the Commission in its consideration of regional transmission planning issues within the SPP RTO.

II. Discussion

A. Cost Estimation Procedures and Variances

1. SPP's Planning Role and Responsibilities Provide a Platform for Regional Solutions to Cost Estimation and Variance Issues.

SPP is aware of the issues related to cost estimation and variances and is actively working both internally as well as with stakeholders to address these issues. However, to

[3] The whitepapers presented by SPP staff at the December 3, 2010 SPC meeting setting forth preliminary reactions to the RSC recommendations are attached hereto as Exhibit 1 and are also available at: http://www.spp.org/publications/SPCAGD&BKGD120310.pdf.

provide context for these issues, and the framework for potential reforms, a basic understanding of SPP's current transmission planning processes is in order.

Under the SPP Membership Agreement and the SPP Open Access Transmission Tariff ("OATT" or "Tariff"),[4] the Transmission Owners in SPP have ceded their transmission planning responsibilities to SPP. However, the Transmission Owners remain responsible for actual construction of transmission facilities and for developing their individual revenue requirements. Section 3.3 of the SPP Membership Agreement describes SPP's planning function as follows:

> [SPP is] responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate state authorities, including the Member's governing board where it serves as that authority.

Section 3.3 of the Membership Agreement further acknowledges the recognized division of interests between the transmission planning function of SPP as the Transmission Provider and the financial and construction responsibilities and ownership interests of the Transmission Owners. Attachment O, Section VI (1), of SPP's OATT reinforces this distinction, stating that the "Transmission Provider shall not build or own transmission facilities. The Transmission Provider, with input from the Transmission Owners and other stakeholders, shall designate in a timely manner within the SPP Transmission Expansion Plan ("STEP") one or more Transmission Owners to construct, own, and/or finance each project in the plan."

Thus, responsibility for project construction and project management rests with SPP's Transmission Owners and is managed through the Transmission Owners' internal processes and interactions with appropriate regulatory authorities. That is not to say, however, that these issues cannot or should not be addressed on a regional basis as part of the evolution to regional cost

[4] The Membership Agreement and OATT are available at: http://www.spp.org/section.asp?group=215&pageID=27

allocation. To the contrary, changes in cost allocation, project cost estimates and variances are not only a concern of the Transmission Owner building the facilities, but potentially impact other SPP Transmission Owners that may share in the costs of such facilities and SPP Transmission Service Customers to whom these costs are allocated through rates. Accordingly, and as next discussed, SPP is actively working to ensure that costs are shared fairly amongst the members and customers. SPP reinforced its historical commitment to equity in cost allocation through Tariff revisions related to Unintended Consequences approved by FERC as part of the Highway/Byway cost allocation methodology filing.[5] These Tariff revisions provide for more frequent and more rigorous reviews for Unintended Consequences in cost allocation, as well as including a provision allowing a member company to go directly to the Markets and Operations Policy Committee to request relief if it believes it has an imbalanced cost allocation.[6]

SPP would like to emphasize that the Highway/Byway cost allocation methodology, as all SPP cost allocation methodologies, is the responsibility of the RSC and was approved by the RSC. A more complete history and explanation of the Highway/Byway cost allocation methodology is included in Appendix A.

2. Efforts Are Ongoing to Develop Regional Enhancements to Address Cost Estimation and Variance Issues.

(a) *Improved Transparency Has Brought Needed Attention to Project Cost Variances.*

SPP staff is currently engaged in the examination of project cost estimate variances and potential improvements to the process used to create the cost estimates. This examination by SPP staff follows the recommendations of the RSC to "review …the significant cost increases and/or overruns of transmission projects that are regionally funded" and to "…evaluate how cost

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5 A more detailed discussion on the history of Unintended Consequences is set forth in Appendix A, hereto.
6 Tariff, Attachment J, § III.D.4.ii.

estimates are established for transmission projects before Cost Benefit Analysis are performed."[7] To date, a preliminary "whitepaper" analysis has been prepared, with further plans in place to develop a more comprehensive examination of these issues.

It is important to note that the current discussion, which responds to the increase in particular transmission cost estimates for Priority Projects, is a product of the openness and transparency of the SPP planning processes and the regionalization of cost allocation. In the past, transmission cost estimates would have tended to remain internal to each member utility, subject only to the utility's internal review and any applicable obligations to regulatory authorities. Adjustments in these initial pre-construction cost estimates would have been handled completely within the utility's management and processes and would not have been publically released.

SPP's Attachment O Transmission Planning Process, including Balanced Portfolio, Integrated Transmission Planning ("ITP") process and Priority Projects, provides transparency into the early stages of the transmission planning process, enabling affected stakeholders access to project cost estimation information.[8] This, of course, is hardly a complete response to the cost estimation issue; however, it does demonstrate that project cost variances are not necessarily a new occurrence.

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[7] These recommendations were reflected in the RSC motions that were adopted at the October 25, 2010 SPC meeting and approved by the SPP Board on October 26, 2010. See RSC Motion 1 and RSC Motion 4.

[8] A comprehensive discussion of the evolution of SPP's cost allocation methodologies, including the market and regulatory changes that prompted SPP to modify its allocation and planning procedures, is contained in Appendix A, hereto. Suffice to note that the proper allocation of new facility costs is, as the FERC has recognized, more "art than science" and that allocation principles that may be appropriate in one market/regulatory/operational environment may be inappropriate in another. For that reason, SPP has periodically modified the manner by which new facilities are priced into the market, with all such proposals being vetted through the stakeholder process and presented to FERC for comment, review and approval.

(b) Proposals Are Currently Being Developed to Standardize Cost Estimation Procedures.

It seems self-evident that improvements to the cost estimation process could reduce the incidence of unexpected project cost variances. Accordingly, to obtain and ensure consistency in the development of cost estimates, SPP staff and stakeholders are working to create a standardized and transparent process for generating project estimates.

While these efforts are currently in their formative stages, the objective is to formulate specific recommendations that will then be vetted through the SPP stakeholder processes.[9] The anticipated end-product should be a significantly enhanced cost estimation process with greater latitude for variance in the early planning and screening stages and tighter variance controls as projects progress toward SPP Board approval and the issuance of Notifications to Construct ("NTCs"). Consideration is also being given to imposing more rigorous scrutiny to costs outside the variance band and assigning costs deemed to be excessive to the responsible cost zone rather than regionally.

At the SPC meeting on December 3, 2010, presentations were made by SPP staff and by Mr. Kip Fox on behalf of SPP's Transmission Owners;[10] both presentations are attached hereto as Exhibits 2 and 3, respectively. While there were some differences in the details of the proposals, both set forth specific objectives and processes that would allow project cost estimates to evolve and become more refined as projects move from conceptual to construction, with multiple points in the process where cost estimates would be updated and subjected to increasingly higher levels of scrutiny and accuracy.

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[9] Resulting changes requiring tariff modifications would be filed with FERC.

[10] The Transmission Owners involved in the concept development of and supporting the Transmission Owner Proposal were: American Electric Power, Oklahoma Gas & Electric Company, Westar Energy, Inc., XCEL Energy—Southwestern Public Service Company, Kansas City Power &Light, Sunflower Electric Power Corporation, Western Farmers Electric Cooperative, Nebraska Public Power District, Empire District Electric Company, Midwest Energy, Inc., Lincoln Electric System, and City of Springfield, Missouri.

SPP staff's proposal includes three stages, with each stage having progressively tighter requirements for cost estimate accuracy and detail of data. In stage 1, when projects are first conceived, cost estimates will be generated by SPP staff using a generic cost estimation tool. The tool will be developed in conjunction with the TWG and will include generic cost data such as cost per mile for specific voltage levels, substation cost estimates, and cost modifiers to account for regional differences, terrain, urban/rural areas, and other considerations. This will allow preliminary estimates to be more readily developed for the purpose of screening large numbers of potential projects and selecting suitable candidates for more detailed study. The output of this initial estimation tool will be a table showing the total cost estimate for each project being considered as well as all of the information used in developing the cost estimates. The availability of this information should simplify the identification of variations in cost estimates and why such variations exist. On an annual basis, SPP staff and the TWG will update the cost data contained in the estimating tool.

Stage 2 of SPP staff's proposal begins after the initial project screening is completed and the list of potential projects has been narrowed to those most likely to be selected. The incumbent Transmission Owner of each project will review and provide a more rigorous assessment of the stage 1 cost estimates to ensure more accurate data is used for subsequent analyses in the selection of projects. Any variances between the stage 1 and stage 2 cost estimates must be accompanied by a detailed explanation of the variance. While this estimate is still considered to be a high-level cost estimate, it is expected to be within a +/-50% band of final construction costs.

Stage 3 of SPP staff's proposal requires further refinement of project cost estimates after the above-referenced analyses are completed but before a final report is submitted to stakeholders and the SPP Board for approval and subsequent NTC issuance.[11] As currently proposed, the incumbent Transmission Owner will be required to submit a completed Standardized Cost Application ("SCA"), which is expected to be a very detailed estimate within a +/-25% band of final construction costs. The SCA will include, among other things, a detailed explanation of variances between the stage 2 and stage 3 estimates.

As explained above, development of the cost estimation procedures is still a significant work in progress. The whitepaper presented by SPP staff served to begin the dialogue and to put in place a framework for continued analyses. SPP commits to provide updates to the Commission as these procedures continue to develop.

(c) Improved Management of Cost Variances Is Under Active Consideration within SPP.

Project cost variances are not a new problem, nor are they unique to the SPP RTO. To the contrary, the Commission has repeatedly dealt with the issue of cost increases and overruns, generally applying a "prudence standard" as the basis for determining a utility's right to recover cost increases and overruns.[12]

SPP's current process tracks project costs and in-service dates for projects that have received an NTC. The Transmission Owner is required to submit quarterly updates of cost estimates and the expected in-service date. These updates are incorporated into a quarterly report that is submitted to the SPP Board/Members Committee, the Markets and Operations Policy Committee ("MOPC") and the RSC. Currently, project developers are required to submit

[11] Projects that receive an authorization to proceed ("ATP") instead of an NTC will not be required to have a stage 3 estimate. ATPs are discussed in greater detail in Appendix A.

[12] See, e.g., *Union Electric*, 27 Mo. P.S.C. (N.S.) 183 (1985) and *Union Electric*, Case No. ER-2007-0002, Report and Order (May 22, 2007).

justification for variances when a cost estimate has increased by more than 20% since the previous estimate.[13]

SPP recognizes modification to the current process is needed to ensure that all variations in cost estimates are monitored with sufficient scrutiny. In this regard, SPP staff presented its initial whitepapers at the SPC meeting on December 3, 2010, proposing a structured procedure to address variances in estimated costs. The staged procedure for developing progressively more refined cost estimates is, as described above, an important component of this process. In addition, other management tools are being considered to minimize the occurrence of, and more effectively respond to, variances in cost increases and decreases.

For example, one proposal being advanced is to utilize the stage 3, or "NTC Project Estimate" ("NPE"), as the baseline for project tracking. In other words, this estimate would serve as the reference point from which all cost variances would be measured throughout the project tracking process and would be the comparative basis for purposes of determining the percentage of variance of estimate updates.

It has also been proposed by SPP staff that a Transmission Owner for a project that has an NPE in excess of $5,000,000 be required to submit updates for that project on a monthly basis, whereas projects under $5,000,000 will require updates on a quarterly basis. These updates would consist of a detailed cost breakdown that mirrors the original SCA, and include comments explaining any variances. Comments from the Transmission Owner would include relevant information regarding any sunk costs, an explanation for the revised cost estimate, and comments as to whether the project should continue. If the cost variance is outside the +/- 25% band for the NPE, the project will be reviewed by an SPP working group.

[13] Decreases in cost estimates are also tracked, but there is currently no requirement for submission of a justification.

SPP staff's proposal envisions that reevaluation of a project by the working group will be based on data and information from both the Transmission Owner and SPP staff, including the original SCA, project tracking data updates, and any comments from SPP staff or the Transmission Owner related to the variances. Such reevaluation would include an analysis of the cost estimate variances and whether the variances are reasonable and appropriate for regional funding or more properly allocated on a zonal basis. The working group may recommend a restudy, if it deems that such is needed based upon the information it is presented with respect to the variances.[14]

Pursuant to the initial proposal by SPP staff, the working group would submit a quarterly report to the SPP RSC and SPP Board/Members Committee regarding the projects it has reevaluated. This report would include the rationale provided for each cost estimate variance as well as comments from the working group recommending whether such a change is reasonable and appropriate for regional funding. If not, the recommendation will include a proposal for further action by the SPP Board/Members Committee. Initial discussions on this matter have included suggestions that such changes that are not reasonable or not appropriate for regional funding would be assigned zonally.

A project's cost estimate may increase by such magnitude that alternative projects should be reconsidered. SPP staff has proposed that all of the following conditions must be met in order to require a restudy:

(i) Latest cost estimate must exceed $10,000,000;

[14] It is important to note that SPP staff recognizes there may be instances where resetting the baseline would be prudent. The working group would determine if and when to reset the baseline cost estimate. Should a baseline cost estimate be reset, the original NPE will still be retained as a monitoring tool.

(ii) If the benefit/cost ratio was the rationale for the project, then the b/c must have changed to be less than 1;

(iii) Actual construction of the project has not yet started; and

(iv) The cost must have increased 30% from the baseline.

If a restudy is required, SPP staff will develop a study scope for approval by the TWG or Economic Studies Working Group ("ESWG"). The resulting study analysis would follow the typical stakeholder process by moving through the appropriate stakeholder working groups and finally to the Board of Directors/Members Committee for final action on whether the original NTC should be revoked. Should the NTC be revoked, an NTC for the alternative project may be approved for issuance.

As the foregoing summary demonstrates, significant time and effort has been devoted by SPP to improving cost estimation procedures and minimizing/managing cost variances. Although much work remains to be done, allowing these efforts to run their course will provide the Commission valuable information concerning these issues and potentially resolve, in whole or part, concerns raised in the Commission's Order.

B. Novation

The Commission's Order raises concerns about the right of novation under SPP's current planning process and the potential that exercising this right could be contributing to increases in project cost estimates. As discussed below, while SPP believes that there are benefits in novations, a comprehensive examination of this issue is currently being undertaken to determine whether, and to what extent, the exercise of a Transmission Owner's novation rights may affect costs.

As a preliminary matter, it is important to distinguish between novations and assignments, as the terms are not interchangeable. In fact, novation and assignment represent alternative options available in cases where a Transmission Owner cannot or does not want to construct a transmission project. An assignment, as permitted by the SPP Membership Agreement, allows the designated Transmission Owner to transfer responsibility for construction of a project, but does not relieve the Transmission Owner of the financial or legal obligation to construct the project in accordance with the NTC.

In contrast, a novation allows the designated Transmission Owner to transfer all legal and financial responsibilities under the SPP Membership Agreement for the timely construction of the project to an entity that is or agrees to become qualified under SPP's process and bound to construct the project as a Transmission Owner under SPP's OATT and SPP Membership Agreement. FERC has specifically held that novation is an appropriate part of the SPP OATT and has rejected arguments seeking to limit novation rights, in whole or part.[15]

There are numerous factors that can result in the decision to assign or novate a transmission project. Funding or financing limitations, increased costs of financing and/or an inability to timely construct the project could prompt a Transmission Owner to assign or novate its responsibilities to a third party.

In an effort to address the concerns that have been raised with respect to novations, SPP staff has presented a multifaceted proposal providing increased transparency through the regional planning and cost allocation process. Specifically, SPP staff has suggested that it provide proposed novations and supporting analysis to the MOPC for review and approval as well as to

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15 *Southwest Power Pool, Inc.*, 128 FERC ¶ 61,018 at P 22.

the RSC for review, before consideration by the SPP Board/Members Committee for approval to file with FERC.

C. Design and Construction Standards

The RSC has recommended SPP consider establishing design and construction standards for transmission projects at 200kV and above that are regionally funded. SPP staff has made an initial proposal in an effort to provide a consistent and economic construction standard that can be implemented by all Transmission Owners in the SPP transmission system. Discussion of design and construction standards is still in its infancy. There are many issues, including legal and liability implications this may impart on SPP, which must be further developed prior to determining any type of construction standard, and whether it is an appropriate and/or a strategic direction desired by the membership.

In order to bring uniformity and economies of scale to regionally funded transmission projects, SPP proposes to develop and maintain design and construction standards. This effort will provide consistency in the bulk transmission system and enhance reliability while reducing compatibility issues by having standard components used by all Transmission Owners and transmission system builders. Ultimately, these standards will be established through a collaborative effort based upon the best practices of Transmission Owners, with the long term goal of better managing construction costs. The final draft of these standards will be submitted to the TWG and then the MOPC for its approval.

Although construction costs may vary based upon location and other factors, establishing standards on the basis of best practices can provide guidelines and set expectations. The initial focus of developing construction and design standards will be on the components that have the greatest variability in cost. The major components currently under consideration for the establishment of regional standards include:

(i) conductor size;

(ii) minimum ampacity value;

(iii) fiber optic ground wire construction standards;

(iv) structure and wooden pole construction specifications;

(v) foundation construction standards;

(vi) substation control room construction standards; and

(vii) insulation and insulation hardware construction specifications.

Although the development of construction and design standards is still in the initial stages, and the breadth of possible standards is unknown, SPP staff has preliminarily suggested it would interpret and apply the regional standards and track projects to ensure the standards are being followed for regionally funded projects. In some circumstances, deviation from the regional standard may be necessary; any requests for deviation would need to be submitted to SPP staff for consideration.

SPP staff's Design and Construction Standards Whitepaper proposed several examples of transmission and substation design standards, including standards for breaker configuration, terminal equipment minimum rating, transmission line design, and minimum conductor sizing. Tables and diagrams for each of these topics were provided in the whitepaper, which is attached hereto as Exhibit 1.

D. Costs and Benefits of RTO Membership and Implications of Member Withdrawal

The Commission's Order raises questions regarding the relative costs and benefits of RTO membership, generally, and in the specific context of Empire. Among other things, the

Commission seeks additional information to better understand the value of "qualitative" benefits of RTO membership and the cost impact to SPP's Missouri customers.

1. <u>Overview of RTO Benefits vs. Costs</u>

To address these issues, SPP has developed an estimate of the annualized value that is created through RTO membership at the aggregate SPP footprint level. The SPP Aggregate Value Proposition starts with an estimate of the value currently being realized by SPP members through the collaboration of all members, facilitated and administered by SPP staff. The additional future value improvement is also estimated based on the completion of defined market development and transmission expansion projects. The analytical framework for this estimate utilizes an economic comparison of two cases. The "base case" assumes that SPP does not exist and all current members operate on a standalone basis without collaboration of any sort. The "base case" is compared to the "change case" that reflects the SPP membership collaboration as it exists today. The SPP methodology reflects a value creation estimate for the SPP membership as an entire entity. Due to the synergy of all of the parts creating value for the entire membership, we do not believe that our methodology lends itself to assigning value to sub-categories of the membership and are therefore unable to provide this information as broken down by state or member.

Two fundamental sources of value are created by the collaboration of members as coordinated and administered by SPP: region-wide optimization and economies of scale. Region-wide optimization reflects the product of operating a power generation, transmission and market system on a regional basis, thereby creating a broader base and scope of resources for optimization. Economies of scale reflects the ability of SPP to provide centralized services to member companies at a lower unit cost than members (or Balancing Authorities) can achieve on an isolated basis.

In addition, the collaboration between SPP and its member companies creates service-related benefits in the following functional areas: reliability coordination; reserve sharing; region-wide transmission planning; and operation of open, transparent energy markets. Each category is described in more detail below.

- Reliability Coordination

SPP has an operations center that monitors all activity on the bulk electrical energy grid 24 hours per day, 7 days per week. In addition to responding to outages and coordinating the response, SPP administers a planning function that assures the grid is highly reliable – minimizing disturbances, outages, duration of outages and congestion. North American Electric Reliability Corporation statistics show that RTO members have a higher average system availability than standalone utilities. Based on estimates of the average cost of an outage multiplied by the total annual SPP load, the SPP reliability services helps its members avoid between **$185** and **$280 million** per year of outage costs.

- Reserve Sharing

SPP administers an operating reserve sharing program for a group of utilities having generation capability. SPP maintains capacity for a minimum daily contingency reserve equal to the generating capacity of the largest unit scheduled to be on-line plus one-half of the capacity of the next largest generating unit scheduled to be on-line. Members share on a pro-rata basis in the cost of this reserve. Half of the reserve is required to be a spinning reserve and the other half a supplemental reserve. This is done in lieu of each generating utility maintaining its own reserves for the loss of its largest unit. The total annual reserve requirement cost avoidance for the Reserve Sharing group is estimated to be between **$280** and **$590** million per year.

- Region-Wide Transmission Planning

SPP's engineering function develops transmission plans for the SPP region that will optimize the effectiveness and efficiency of the transmission grid to enable access to the lowest cost sources of power generation for all members. SPP identifies transmission expansion projects that benefit the region and a regional cost allocation methodology helps to build out the needed incremental transmission capacity. Projects already built have created **$5 million** per year of benefits. The Balanced Portfolio Projects and the Priority Projects are in the process of engineering and construction. When implemented over the next decade, the total value to the SPP region is estimated to be **$480 million** per year.

In addition to the above referenced studies, SPP staff conducts studies upon request for: (i) generation interconnection and transmission upgrades and (ii) aggregate studies to facilitate transmission service request, and also performs integrated planning studies over 10- and 20-year planning horizons. SPP serves as an unbiased, objective expert witness to testify at regulatory commissions on the impact of proposed projects to the integrity of the power grid. The cost to procure similar unbiased expert testimony backed by objective studies would conservatively cost **$20 million** per year.

- Operation of Open, Transparent Energy Markets

SPP operates an Energy Imbalance Service ("EIS") market. This market produces net trade benefits to the region. These benefits are defined as the amount the short-term costs of power production within the market footprint are reduced as a result of the regional security-constrained economic dispatch ("SCED") implemented for the EIS market. A study of the benefits in the first 12 months of the operation of the EIS market estimated the benefits to the SPP region to be **$100 million** per year of net trade benefits.

SPP is in the process of implementing highly liquid and efficient Day Ahead and Real Time Balancing markets. These markets will allow unit commitment to be performed on a region-wide basis. An independent study[16] has estimated the average annual net trade benefits of the proposed **Integrated Marketplace** to be approximately **$150 million** per year beginning in 2014, which is in addition to the $100 million per year of net trade benefits from the EIS market.[17] The implementation of the Consolidated Balancing Authority will centralize Balancing Authority resources and avoid approximately **$10** and **$15 million** in costs per year for SPP members.

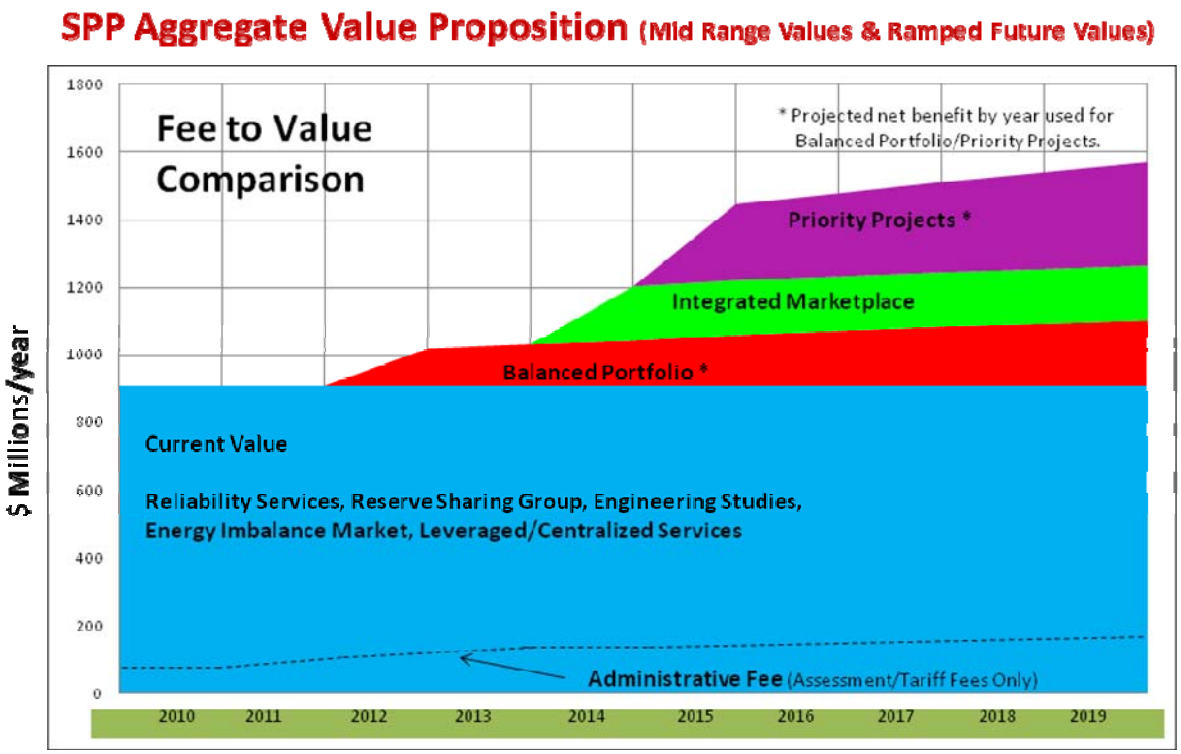
In short, SPP provides a series of leveraged centralized services to members, customers and member Balancing Authorities. Due to the economies of scale involved, SPP can provide these services at a higher quality and lower unit cost to members than they could provide them for themselves individually. These centralized functions include: Training, Tariff Administration and Scheduling, Regulatory, Compliance, Settlements and Contract Services. The annual value of these services to the SPP region is estimated at between **$100** and **$125 million** per year.

Summary	**Annual Value (in millions)**
Value of services currently provided.	**$ 690 - 1,120**
Value of future services (transmission, markets)	**$ 640 - 645**
Grand Total – Gross Benefits	**$1,330 - 1,765**

16 This study was paid for by the RSC, and was accepted and approved by the RSC. The study was performed by Ventyx and the final report was issued on April 7, 2009, a copy of which is available at: http://www.spp.org/publications/SPP%20Report%20April%20v8.pdf.

17 The value of the current EIS market is estimated to be $100 million per year.

The following chart is an initial estimate demonstrating the increasing value of SPP membership compared to the increases in the administrative fee.



2. <u>Benefits of SPP Membership for Empire District Electric Company</u>

The Commission's Order raises concerns regarding the impacts that the cost allocation of Priority Projects and the ITP[18] and the cost increases for those projects will have on Empire. With respect to the ITP, however, SPP must emphasize to the Commission that it *will not be issuing any NTCs for the 2010 ITP20-Year Assessment ("ITP20") projects*.[19] NTCs are only issued for approved projects requiring expenditures *within the financial commitment horizon*, i.e.

[18] The ITP process is discussed in greater detail in Appendix A.
[19] Drafts of the ITP20 Report and the ITP Manual are available at: http://www.spp.org/section.asp?pageID=128.

the next four years.[20] Although this is a topic that likely warrants a more expansive discussion, the instant comments are offered to briefly address the benefits of SPP membership that have been realized by Empire to date.

Although the level and allocation of costs for construction of transmission facilities are relevant factors, consideration of these costs must be in the broader context of the benefits that Empire enjoys through SPP membership. Any such analysis would necessarily entail examination of the services and costs that Empire would have to bear outside of the SPP RTO. A closer look at Empire's operations is an appropriate first step in this analysis.

Empire has a relatively small service area. Its service territory accounts for approximately 2-3% of the SPP transmission footprint. Consequently, but for its membership in SPP, Empire would have relatively few resource alternatives available to it.

Moreover, as an active member in the SPP stakeholder process, Empire has appropriately and prudently utilized the SPP OATT to expand its horizons and take advantage of resources outside of its service area. Access to greater (and, presumably, less costly) resource options are clearly advantageous and beneficial to Empire. Furthermore, under its SPP Network Transmission Service arrangements, Empire has approximately 542 MW of inbound transmission for external resources with virtually no net access charges, which has resulted in considerable transmission benefits at little to no incremental cost. This includes the new resources available to Empire and totaling 457 MW outside the Empire service area (Elk River, Plum Point, Iatan II and Meridian Way). This also includes 250 MW of renewable resources. Access to such renewable resources has helped Empire to satisfy Missouri Renewable Energy

[20] While no NTCs will be issued following the SPP Board's approval of the 2010 ITP20, which is anticipated in January 2011, the Board will also consider the 2010 STEP at their January 2011 meeting and it is expected that NTCs will be issued for reliability projects. A draft of the 2010 STEP is available at: http://www.spp.org/section.asp?group=2005&pageID=27.

Standards[21] , by utilizing optimal wind resources that would otherwise not be available within its service area. Empire has utilized the EIS market to manage the variability of its wind farms, and but for SPP and SPP's EIS market, Empire's use of extensive wind resources would be less feasible. Withdrawal of Empire from the SPP transmission system would require that Empire reserve at least 442 MW of SPP Point-to-Point transmission service in lieu of its current SPP Network Service in order to utilize its off-system resources located elsewhere within SPP. This would currently have an annual cost of approximately $8 million.

Empire has recognized the benefits that SPP provides. On April 13, 2010, Empire filed an application with the Arkansas Public Service Commission ("APSC") for approval of its continued participation in the SPP RTO.[22] This application was required to be filed with the APSC within 60 days after the third anniversary of the implementation of SPP's EIS market. In the application, Empire sought "authority to allow the SPP RTO to continue to have operational control and authority to direct the day-to-day operation of facilities with high-side voltage of 60kV and above in order for SPP to carry out its responsibilities as a Transmission Provider and Reliability Coordinator." Empire stated that continuing to allow the SPP RTO to have such operational control is "in the public interest." In addition, Empire's application explained that "*SPP continues to provide valuable and required services to Empire that would be more costly and expensive for Empire to replicate*." Specifically, both a June 28, 2010 letter filing by Empire and the amended direct testimony of Richard L. McCord[23] stated that the net savings to Empire from participating in the EIS market operations over a 3-year time period was $19.2 million. Mr. McCord further testified that "there are significant ratepayer benefits being

21 Codified at RSMo 393.1020, 393.1025 and 393.1030.

22 APSC Docket No. 04-137-U

23 APSC Docket No. 04-137-U, Amended Direct Testimony of Robert McCord, filed May 20, 2010. Mr. McCord testified on behalf of Empire as Director of Supply Management.

achieved through Empire's participation in the SPP."[24] In addition, Diana Brenske, Director, APSC Electric Utilities Section, stated in reply testimony filed on May 21, 2010, that "[g]iven the positive benefits of participation in the SPP RTO and the EIS market reported by the SPP Utilities,[25] I recommend that the [APSC] approve their continued participation."

In addition, Empire has referred to other benefits that have resulted from its SPP RTO membership and market participation. If Empire was not an SPP member, it would have to build additional transmission facilities. In its 2009 fourth quarterly financial report, filed with FERC on April 19, 2010, Empire gave an example of this, stating that "[a] new combustion turbine previously scheduled to be installed by the summer of 2011 will be delayed until 2014 as our generation regulation needs are being met through a combination of our existing units and the SPP energy imbalance market."[26]

Finally, SPP notes that in 2005, Charles River Associates ("CRA") performed a Cost-Benefit Analysis ("2005 CBA") in connection with the implementation of SPP's EIS Market.[27] The final report on the results of the 2005 CBA was released on April 23, 2005, with a revised version released on July 27, 2005. While stakeholders participated throughout the study process, the final study reflected the independent analyses, findings and judgment of CRA.

Although this study was completed in 2005, SPP believes it is still relevant to demonstrating the value to a Transmission Owner of membership in SPP. As stated in the Commission staff's Memorandum in Support of Stipulation in Docket No. EO-2006-0141, filed

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24 APSC Docket No. 04-137-U, Testimony of Robert McCord, filed May 20, 2010.

25 For purposes of Docket No. 04-137-U, the benefits of SPP RTO participation were studied for Southwestern Electric Power Company, Oklahoma Gas and Electric Company and Empire.

26 The Empire District Electric Company FERC Financial Report, FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, dated April 19, 2010.

27 This study was funded by the RSC and was accepted and approved by the RSC. The results are available at: http://www.spp.org/publications/CBARevised.pdf.

February 24, 2006, the "clear result of the 2005 CBA is that SPP as an RTO is cost beneficial for the SPP Region", and this benefit can also be specifically seen in Missouri. Empire's membership in particular was projected to benefit its ratepayers in the approximate amount of $48.5 million as a Transmission Owner in SPP over a ten-year time period. The benefit to Missouri ratepayers as a whole was estimated to be approximately $55.4 million over a ten-year time period. CRA showed that the SPP Transmission Owners would otherwise incur an additional $70.5 million in costs by operating as stand-alone entities, with each operating under its own tariff.[28]

3. Implications of Member Withdrawal from SPP

Membership in the SPP RTO is voluntary, as is withdrawal. Any member may withdraw; however, there is a specific process for withdrawal and there are consequences to withdrawal, such as payment of an exit fee. SPP considers that a withdrawal has occurred whether a member completely withdraws from membership or decides to withdraw as a Transmission Owner and rejoin as a Non-Transmission Owner. There has been some discussion that a withdrawing member could contract for certain services with SPP; however, this is not a guaranteed option and should not be relied upon in making decisions regarding membership. Any provision of contract services must first be approved by the SPC and the Finance Committee, followed by the SPP Board/Members Committee. Historically, approval of contract services has been based upon a strategic driver to invite membership in SPP; SPP has not considered such services to facilitate the exit of a member. In addition, FERC has been very clear specifically regarding the provision

[28] Commission staff, in its *Memorandum of Support of Stipulation and Agreement* in Case No. EO-2006-0141, opined that the results of the 2005 CBA provided a strong indication of positive net benefits to Missouri ratepayers from KCP&L and Empire's memberships in SPP. Staff also noted that "[w]ith the additional flexibility provided to the RTO to dispatch generation, the RTO is better able to manage congestion and thereby improve the reliability of the transmission system." Staff continued to state that "[i]f anything, removing the responsibilities to also manage to provisions of transmission service should allow the TOs to put greater focus on issues related to public safety."

of market services to non-RTO members. There is no indication today that its position has changed, so other than participation as an external generator, continued market access (and its benefits) should not be assumed in assessing membership.[29]

4. Empire is Multi-Jurisdictional

Although it is based in Joplin, Missouri, Empire's service area is not confined to the State of Missouri, and therefore Empire's membership in SPP is not a single state matter. Empire also has facilities in and is a jurisdictional utility in Kansas, Oklahoma and Arkansas. Missouri cannot order Empire to remove its facilities in all states from the SPP OATT. Empire is also FERC jurisdictional, which means that in addition to obtaining the required approvals from these state regulatory authorities, Empire would have to obtain FERC approval prior to withdrawing from SPP. FERC's analysis for addressing a requested withdrawal is discussed below.

FERC has indicated that although RTO membership is voluntary, a public utility that is FERC jurisdictional and is seeking to transfer operational control of jurisdictional facilities to or from an RTO must submit a filing to FERC under section 205 of the Federal Power Act.[30]

[29] In 2008, MISO proposed making available a Market Service to non-members, which would differ from RTO participation in several ways. A Market Service customer would not turn over functional control of its transmission facilities and would continue to administer its own tariff and its own transmission planning. In addition, a Market Service customer would continue to charge a pancaked rate for transmission service through or out of its system. The Market Service proposal also included a Market Integration Transmission Service to provide firm transmission service over its transmission system as necessary to support its market-based generation dispatch, and would be provided on an "as available" dispatch.

FERC rejected Midwest ISO's proposal for Market Service, and explained that in determining whether a proposed RTO service is just and reasonable, that it must consider the effects of the proposal on, among other things, the ability of the RTO to satisfy its obligations under FERC Order No. 2000. FERC noted that RTOs provide increased efficiency to wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently and operating markets for energy capacity and ancillary services. FERC further opined that the competitive, efficiency, reliability and other benefits of RTOs can be best achieved if there is one transmission operator in the region, concluding that the Market Service Proposal was incompatible with these goals and could create potential disincentives for new and continued RTO membership.

[30] *Guidance on Regional Transmission Organization and Independent System Operator Filing Requirements under the Federal Power Act*, 104 FERC ¶ 61,248, at P 2 (2003) ("*RTO Guidance Order*").

Several Transmission Owners have either withdrawn or attempted to withdraw from RTOs,[31] and in none of these cases did the Transmission Owner withdraw from the RTO and take back control of all functions themselves. Instead, in each case, the Transmission Owner either committed to join a new RTO or, in the case of Louisville Gas & Electric Co. and Kentucky Utilities Co. (“LG&E”), created an independent entity to oversee certain functions and duties. In reviewing each Transmission Owner's request to withdraw from an RTO, FERC has assessed withdrawal requests on the basis of whether they fulfill existing obligations, comply with FERC orders, and are just and reasonable.

Beginning with the LG&E withdrawal from the Midwest ISO in 2006, FERC generally has utilized a three-part test for approving a Transmission Owner's request to exit an RTO. To receive approval to withdraw from an RTO, a Transmission Owner must demonstrate that: (a) the withdrawal proposal satisfies the terms of the relevant RTO agreement, such as the SPP Membership Agreement or the Midwest ISO Transmission Owners Agreement; (b) the withdrawing Transmission Owner's replacement arrangements must comply with Order Nos. 888 and 890 and any proposed deviations from the *pro forma* OATT must be demonstrated to be

[31] The transmission owners that have either withdrawn or attempted to withdraw from RTOs include: (1) Louisville Gas & Electric Co. and Kentucky Utilities Co. (collectively "LG&E") withdrew from Midwest ISO in 2006; (2) Duquesne Light Co. ("Duquesne") attempted to withdraw from PJM in 2008 but later reversed its decision; (3) American Transmission Systems Inc. ("FirstEnergy") is currently in the process of withdrawing from the Midwest ISO; and (4) Duke Energy Ohio and Duke Energy Kentucky (collectively "Duke") is currently in the process of withdrawing from the Midwest ISO.

"consistent with or superior to" the OATT; and (c) the withdrawing Transmission Owner's replacement arrangements must be just and reasonable and not unduly discriminatory.[32]

(a) Satisfaction of Relevant RTO Agreements

In each of the above cited cases, FERC has reviewed the relevant RTO Agreement provisions governing withdrawal/termination to determine whether the withdrawal proposal satisfies all contractual requirements. For example, in *LG&E*, FERC determined that LG&E had either satisfied or had committed to satisfy the withdrawal provisions of the Midwest ISO Transmission Owners Agreement, including: (1) notice of withdrawal; (2) holding existing customers harmless; (3) payment of an exit fee (subject to a final calculation of the fee upon the termination date); (4) negotiation of remaining construction obligations; and (5) receipt of all necessary regulatory approvals (subject to completion of regulatory proceedings).[33] FERC also has required withdrawing Transmission Owners to submit subsequent filings addressing obligations such as the payment of exit fees and agreements regarding continuing construction obligations.[34] The RTO withdrawal precedents make clear that FERC will hold a Transmission Owner to its obligations under the applicable RTO agreement(s) and condition any approvals on complete fulfillment of all requirements.

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[32] *See LG&E Order* at PP 3, 27. FERC has reiterated and applied this test in each subsequent transmission owner withdrawal proceeding. *See Duquesne I Order* at P 28; *FirstEnergy Order* at P 27; *Duke Order* at P 14. In the *LG&E Order*, in addition to the three-part test articulated above, FERC imposed a fourth condition on LG&E's withdrawal from the Midwest ISO. FERC had previously approved LG&E's 1997 merger on the basis of LG&E's membership in the Midwest ISO. As an additional condition of its withdrawal from the Midwest ISO, FERC required LG&E to institute a replacement arrangement that would continue to mitigate market power concerns, which LG&E satisfied by naming SPP as Independent Transmission Organization ("ITO") and the Tennessee Valley Authority as reliability coordinator. *LG&E Order* at P 80. This fourth condition has <u>not</u> been applied in subsequent cases involving transmission owner withdrawal from an RTO.

[33] *See LG&E Order* at PP 31-64. In reviewing Duquesne's request to withdraw from PJM, FERC assessed Duquesne's application to determine whether Duquesne complied with the withdrawal provisions of both the PJM Owners Agreement and the PJM Reliability Assurance Agreement. *See Duquesne I Order* at PP 5-6, 48-54, 81-99. In the *Duke Order*, FERC assessed whether Duke complied with or committed to comply with, the withdrawal requirements of the Midwest ISO Transmission Owners Agreement and the Midwest ISO Balancing Authority Agreement. *See Duke Order* at PP 70-77, 80.

[34] *See, e.g., FirstEnergy Order* at PP 51-52, 54.

(b) Replacement Arrangement Compliance with Order Nos. 888 & 890 - Deviations from Pro Forma and "Consistent with or Superior to" Standard

In each of the RTO withdrawal cases except for LG&E, the Transmission Owner has proposed withdrawing from one RTO and joining another.[35] In the *Duquesne II Order*, FERC determined that switching from one RTO to another and becoming subject to the new RTO's FERC-accepted tariff satisfied the "consistent with or superior to" requirement.[36] In contrast, LG&E did not propose to align with another RTO following its withdrawal from the Midwest ISO; however, FERC conditionally accepted, subject to compliance filings providing certain revisions, deviations from the *pro forma* OATT that were necessary for LG&E to satisfy its merger conditions regarding market power, rate pancaking, curtailment, and operational independence through the creation of the ITO and reliability coordinator arrangements.[37]

(c) Just and Reasonable Replacement Arrangements

In the Duquesne withdrawal proceeding, FERC indicated that the justness and reasonable analysis includes an analysis of both the Transmission Owner's replacement arrangements and its ultimate compliance with all of its contractual withdrawal obligations.[38] Included in this analysis is an assessment of the adverse effects on remaining RTO members as a result of the Transmission Owner's withdrawal. In *Dusquesne I* and *Dusquesne II*, FERC's explained that the review of the justness and reasonableness of a proposed Transmission Owner withdrawal must take into consideration FERC policies and precedent and the possible "substantial impact on other market participants and the markets themselves."[39]

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35 FirstEnergy and Duke have proposed to withdraw from the Midwest ISO and join PJM, and Duquesne proposed to withdraw from PJM to join the Midwest ISO but subsequently decided to remain in PJM.

36 *See Duquesne II Order* at P 42.

37 *See LG&E Order* at PP 108-117, 125-128, 138-142, 166-168.

38 *Duquesne I Order* at P 127; *Duquesne II Order* at P 43.

39 *Duquesne I Order* at P 128; *Duquesne II Order* at P 32; *see also ISO New England, Inc., et al.*, 109 FERC ¶ 61,147, at P 41 (2004).

In summary, in its most recent review of a Transmission Owner request to withdraw from an RTO, FERC has continued to apply the standard first articulated in the *LG&E Order*.[40] FERC has reviewed the replacement arrangements proposed by the departing Transmission Owner to determine whether they comply with the *LG&E Order* standards, as set forth above.

III. CONCLUSION

The Commission's Order raises important issues affecting the process by which transmission projects are selected and the costs of those transmission projects are allocated into the SPP service territory. In many respects, the concerns identified by the Commission are shared by SPP, as evidenced by the considerable efforts currently underway to further improve transmission planning and project tracking within the SPP footprint. Specific proposals are being developed to inject greater discipline in the methods used to estimate and track project costs. These proposals are intended to improve the reliability of project cost estimates and reduce the incidence of cost variances. Initiatives are also underway to explore alternatives to better manage and assign responsibility for cost variances. Finally, as it has in the past, SPP will continuously monitor market, regulatory and operational conditions to ensure that its planning and cost allocation procedures are designed to optimize the benefits of RTO membership.

With respect to Empire, SPP respectfully requests that the Commission take no action at this time due to the following reasons: (a) Empire has and will continue to receive a great deal of benefit from SPP membership and its participation in the EIS market; (b) no NTCs will be issued from the ITP20, (c) the ITP10, which is scheduled to be approved in January 2012, will provide significantly greater detail on underlying, lower-voltage upgrades, benefits and costs, which should provide a greater level of clarification to the Commission; and (d) the requisite

[40] *See Duke Order* at P 14.

Unintended Consequences review is required by 2013 and under development, and the results of that analysis may ameliorate negative financial impacts to ratepayers in states where Unintended Consequences are found to exist. In addition, the Stipulation and Agreement approved by the Commission[41] in Case No. EO-2006-0141 requires Empire to file with the Commission a completed Interim Report on or before February 1, 2012. The Stipulation requires Empire to collaborate with Staff and the Public Counsel regarding issues they consider critical in a proper cost-benefit analysis. Empire's Interim Report will compare the costs and benefits of participation in SPP during a recent 12-month test period.[42] SPP believes that the Interim Report will provide important material that the Commission should consider prior to making any determinations with respect to Empire's membership in SPP.

In addition, Empire is not jurisdictional solely in Missouri and withdrawal from SPP would require approval in multiple states and by FERC. SPP membership has provided substantial benefits to Empire and because of its participation in the EIS market, Empire has been able to utilize significant wind resources, as well as avoid building new transmission facilities and delay construction of generation facilities. The Stipulation and Agreement entered into among the Empire, SPP, Commission staff, KCP&L It is important that this Commission consider the benefits provided by SPP and the costs that Empire would incur if it were operating as a stand-alone utility. Although it is an important issue, there is a great deal more to the overall equation of SPP benefits than simply looking at cost allocation.

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[41] Commission Case No. EO-2006-0141, Order Approving Stipulation and Agreement, issued on June 13, 2006, with an effective date of June 23, 2006, as amended by the Amended Order Approving Stipulation and Agreement, issued on July 13, 2006, with an effective date of July 23 2006.

[42] *See* Commission Case No. EO-2006-0141, Stipulation and Agreement, Sections II.A.(1) and II.D.(1).

Respectfully Submitted,

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APPENDIX A

Background on Cost Allocation Methodologies,

Transmission Planning and Unintended Consequences

APPENDIX A

Background on Cost Allocation Methodologies, Transmission Planning and Unintended Consequences

1. SPP Cost Allocation Methodologies

SPP has responded to changing market and regulatory conditions through the development of new and innovative approaches to cost allocation and regional planning. SPP's Base Plan Funding cost allocation methodology ("Base Plan Funding"), which marked the first step in SPP's attempt to address regional planning and cost allocation issues, was followed by the Balanced Portfolio approach, which built upon and expanded the regional pricing principles of Base Plan Funding. The evolution and implementation of these various initiatives ultimately led to refocused planning priorities that de-emphasized reliability-driven, localized solutions in favor of regional solutions more compatible with the development of robust transmission systems and markets. Indeed, in SPP, the notion that an extra high voltage ("EHV") upgrade is readily identifiable as a "reliability-based" versus an "economic-based" upgrade is no longer valid. The criteria that served to delineate such projects have largely blurred and become outdated, with today's economic project constituting tomorrow's reliability project. The lesson learned throughout the process is that transmission planning and cost allocations are not a static exercise – adjustments must continue to be considered, and changes implemented, as dictated by the dynamic changes taking place within the SPP Region.

As part of the effort to keep pace with ever changing market conditions, the Synergistic Planning Project Team ("SPPT") was created by the SPP Board to address: gaps and conflicts in all of SPP's transmission planning processes including Generation Interconnection and Transmission Service; to develop a holistic approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The SPPT observed that

SPP's processes resulted in numerous cost allocation methodologies. SPP members and staff expressed concern that such cost recovery methods were fragmented, confusing, and difficult to administer as they required a complex system to track cost by project over the life of the project. The SPPT recommended expanding and including a comprehensive review of all cost allocation methodologies for possible consolidation under a unified system using the recommended "Highway/Byway" approach.[1]

The Highway/Byway methodology is based on the FERC's core cost causation principles; namely, those who benefit from new transmission facilities should pay the costs of building the facilities. Large scale, EHV facilities tend to provide benefits across a wider region, while smaller facilities benefit more discrete areas within that region. Moreover, influenced by the realities of an integrated network[2] and FERC policy such as Order No. 890, transmission system planning in SPP has evolved from a utility-by-utility approach focusing primarily on maintaining reliability at the local level to a region-wide approach to the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities facilitated by reduced congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy efficiency technologies, and reduced carbon dioxide emissions. Guided by these

[1] SPP filed OATT revisions to implement Highway/Byway with FERC on April 19, 2010. A copy of the complete filing is available at: http://www.spp.org/publications/2010-04-19_Highway-Byway%20Cost%20Allocation_ER10-1069.pdf. FERC approved Highway/Byway on June 17, 2010. A copy of the FERC Order approving Highway/Byway is available at : http://www.spp.org/publications/2010-06-17_Order%20-%20Highway-Byway%20Cost%20Allocation_ER10-1069.pdf.

[2] The Commission and the courts have long held that, given the integrated nature of a transmission system, rolled-in treatment for transmission upgrades is appropriate. *See, e.g.*, *Maine Public Service Co. v. FERC*, 964 F.2d 5, 8-10 (D.C. Cir. 1992); *Northeast Utilities Service Co.*, 60 FERC ¶ 61,012 (1992), *on remand from City of Holyoke Gas and Elec. Dept. v. FERC*, 954 F.2d 740, 742-43 (D.C. Cir. 1992). Moreover, the Commission has previously stated that it is "the policy of this Commission to roll-in all transmission facilities," *Idaho Power Co.*, 3 FERC ¶ 61,108, at 61,296 (1978), and that it "strongly favors the use of the rolled-in method of transmission allocations," *Niagara Mohawk Power Corp.*, 42 FERC ¶ 61,143, at 61,529 (1988) (*quoting Otter Tail Power Co.*, 12 FERC ¶ 61,169, at 61,420 (1980)).

principles, the RSC developed the Highway/Byway proposal to govern future transmission cost allocation in the SPP Region.

Highway/Byway reflects a broader, more contemporary perspective that moves away from a reliability-based, zonally-focused cost allocation methodology to a methodology that is more closely aligned with SPP's new Integrated Transmission Planning ("ITP") process and the need for and benefits of regional, higher-voltage solutions. To that end, the Highway/Byway methodology allocates the costs of future transmission facilities based on the voltage level of the particular facility, with the cost of EHV facilities (operating at or above 300 kV) allocated 100% to the regional rate, the cost of mid-tier facilities (operating above 100 kV and below 300 kV) allocated on a one-third/two-thirds, regional to zonal basis, and the cost of low voltage facilities (operating at or below 100 kV) allocated entirely to the zonal rate. By allocating costs in this manner, the Highway/Byway methodology provides a mechanism through the SPP Open Access Transmission Tariff ("OATT" or "Tariff") that appropriately allocates the costs of projects developed in a comprehensive regional planning process.

The Highway/Byway methodology applies to all Base Plan Upgrades for which a Notification to Construct[3] is issued after June 19, 2010, including any high priority upgrades[4] approved for inclusion in the annual SPP Transmission Expansion Plan by the SPP Board of Directors, and Base Plan Upgrades associated with wind generation facilities.[5] The Highway/Byway methodology will not apply to upgrades identified in SPP's generation

[3] SPP issues Notifications to Construct pursuant to Section VIII.4 of Attachment O after a new transmission project is either approved for construction under the STEP or is required to provide service pursuant to a Service Agreement. Tariff at Attachment O § VIII.4.

[4] A high priority upgrade is an economic upgrade recommended by SPP for inclusion in the STEP based on the results of a high priority study requested by SPP stakeholders. *See id.* § IV.3.

[5] 300 kV and above Base Plan Upgrades associated with wind generation resources will be allocated 100% regionally. *See id.* at 7-9.

interconnection process or Service Upgrades identified through SPP's Aggregate Transmission Service Study process that do not qualify as Base Plan Upgrades.

2. Transmission Planning

(a) Priority Projects

In April 2010, SPP was directed by the SPP Board of Directors to implement the SPPT's recommendations for creating a robust, flexible, and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP's future needs. Development of Priority Projects was one major recommendation[6]. SPP was charged with identifying, evaluating, and recommending Priority Projects that would improve the SPP transmission system and benefit the region, specifically projects that reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions. SPP has produced three series of Priority Projects reports[7] that have been completed by SPP staff with input from stakeholders and the Transmission Working Group ("TWG"), Economic Studies Working Group ("ESWG"), Cost Allocation Working Group ("CAWG") Markets and Operations Policy Committee ("MOPC"), Strategic Planning Committee ("SPC") and the Board of Directors ("SPP Board"). There were six projects that were identified as Priority Projects which achieve the strategic goals identified in the April 2009 SPPT report.[8] Analysis has demonstrated that these projects will accomplish the goals set forth in the SPPT's recommendation. There are also additional benefits, which have not been measured, but include

[6] The ITP process was also a major recommendation of the SPPT and is discussed herein.

[7] The final report, the SPP Priority Projects Phase II Final Report, approved April 27, 2010, is available at: http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf.

[8] The Priority Projects include: (1) the double-circuit 345-kV line from Spearville, Kansas; to Comanche County, Kansas; to Medicine Lodge, Kansas; (2) the double-circuit 345-kV line from Comanche County, Kansas, to Woodward, Oklahoma; (3) the double-circuit 345-kV line from Woodward, Oklahoma to Hitchland, Texas; (4) the 345-kV line from Nebraska City, Nebraska; to Maryville, Missouri; to Sibley, Missouri; (5) the 345-kV line from Valliant, Oklahoma to Texarkana, Texas; and (6) new equipment in Tulsa County, Oklahoma

particularly without limitation, enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits.

On April 27, 2010, the SPP Board approved the Priority Projects Phase II Final Report. An initial cost estimate of the Priority Projects at that time identified the cost of constructing the Priority Projects at approximately $1.145 billion. In an effort to promote transparency and open communication, this preliminary estimate was released. Subsequent pre-construction estimates released at the October 12, 2010 MOPC meeting estimated the cost at $1.416 billion.

(b) Integrated Transmission Plan

Although the issue at hand relates to cost increases in the Priority Projects, SPP wanted to address the ITP process as it was also referenced in the Commission's Order. The first phase of the ITP, the ITP 20-Year Assessment ("ITP20"), is scheduled to be approved by the SPP Board in January 2011 and SPP thought it would be helpful to provide some additional information on the ITP process generally and the ITP20.

In response to the changing needs of the SPP Region and based upon the recommendation of the SPPT, SPP and its stakeholders developed the ITP process, which is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals to the SPP region in both the near term and long-term. The intent of the ITP is to enable SPP and its stakeholders in the development of a cost-effective, flexible, and robust transmission grid that provides regional customers with improved access to the SPP region's diverse resources. Development of the ITP was driven by planning principles developed by the SPPT, including the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs. In its 2009 report, the SPPT identified several goals for the ITP based on the evolving needs of the SPP Region, including (among other things): (1) integrating west to east portions of the SPP grid to enable renewable resources located primarily in the west to reach load centers located mostly in the east; (2) providing support for the Aggregate Transmission Service Study process; (3) providing relief to the generation interconnection queue; and (4) relieving known congestion.[9]

The ITP is an three-year study process that assesses the SPP region's transmission needs in the long- and near-term by including 20-year, 10-year and Near-Term Assessments and targeting a reasonable balance between long-term transmission investment and customer congestion costs, as well as many other benefits. The ultimate goal of the ITP process is to develop, to the extent reasonably practical, a demonstrable correlation between the actual allocation of costs and the benefits received over time.[10]

The ITP20 is the first ITP looking into the future 20 years as required by OATT Attachment O, Section III. The ITP20 is an expansion on the annual SPP Transmission Expansion Plan ("STEP"), which is the 10-year transmission expansion plan in place since 2006. The concept for this 20-year look into the future arose from the 2009 Synergistic Project Planning Team, as a means to develop a flexible EHV backbone network. The process utilizes a diverse array of power system and economic analysis tools to identify cost-effective robust backbone projects which will provide the transmission system flexibility to reasonably

9 *See* SPPT Report at 11, 16.

10 The ESWG was also formed in conjunction with the development of the ITP, and along with the TWG, will maintain the processes and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the 20-year and 10-year assessments. The TWG will maintain the process on an ongoing basis for qualifying and quantifying the transmission projects for the Near-Term Assessment.

accommodate possible changes characterized by the various futures (scenarios) depicted in the assessment. Projects identified in the ITP20 provide benefits to the region across multiple futures, and create flexibility for SPP to meet future needs. This effort has been driven by numerous interactions with stakeholders and with significant support from the ESWG and TWG. This plan differs from the earlier EHV plans in the level of detail and effort that has gone into its preparation. The ITP20 will be repeated on a three year cycle.

ITP recommendations reviewed by the Market Operations and Policy Committee, the RSC and approved by the SPP Board will allow staff to issue Notices to Construct ("NTC") for approved projects *within the financial commitment horizon*, which means that NTCs will only be issued for projects in which funds are to be expended within 4 years. *SPP will not be issuing any NTC letters for projects identified in the ITP20*, as those projects are outside of the financial commitment horizon. Authorizations to Plan ("ATPs") will be issued for projects needed beyond the financial commitment horizon.[11] ATPs are defined in the ITP Manual[12] as a status given to a project which has been approved by the SPP Board and for which an NTC has not yet been issued because it is outside of the NTC financial commitment window.

The ITP Manual describes how the 20-Year and 10-Year plans will be incorporated annually into the Near-Term Assessment. Specifically, these longer range plans and the ATPs serve as part of a pool of solutions from which the nearer term plans (Near-Term Assessment, Generation Interconnection, Transmission Service Request, Screening Studies) draw to develop and conclude the best regional solution for the SPP footprint, without losing sight of the long term goals of SPP and stakeholders.

11 All of the projects for which ATPs are issued will be posted on the SPP website.

12 A draft version of the ITP Manual is available at: http://www.spp.org/section.asp?pageID=128.

Projects with ATPs will be included in future Aggregate Study and Generation Interconnection study models if needed as solutions for those study objectives. When added, Projects with ATPs will be included in the model that corresponds to the expected in-service date of each project and all subsequent models. Projects with ATPs that have an in service date that is beyond the year being modeled, will be available for advancement as a solution in the current study if it resolves one of that study's issues. Also, projects with ATPs are re-evaluated during successive ITP studies to insure their continuing value or need.

A project subject to an ATP will only get an NTC if construction expenditures for it need to start within the NTC financial commitment window regardless of the driver for the need (Generation Interconnection, Transmission Service Request, Near-Term Assessment, ITP 10-year Assessment, or ITP20). If a project is determined to be no longer of value its ATP will be rescinded. This could result in a requirement for a different solution if there are still power system issues that need to be addressed whether those needs are a result of changes in planning scenarios, anticipated load growth, generation assets, public policy, transmission service obligations, or generation interconnection obligations.

3. Unintended Consequences Review

(a) History

In originally adopting its Base Plan Funding cost allocation methodology, SPP adopted Tariff language requiring it to review the reasonableness of the Base Plan Upgrade regional and zonal cost allocation factors at least once every five years, or more frequently if SPP or the RSC believes that circumstances warrant a review.

Additionally, for each STEP, SPP must calculate the cost allocation impacts of Base Plan Upgrades to each Transmission Customer within the SPP Region, with the results of this analysis being reviewed by the SPP Regional Tariff Working Group ("RTWG") for any unintended consequences.

Since the adoption of these requirements, SPP and its stakeholders have endeavored to ensure that transmission cost allocation does not result in unintended negative cost consequences to customers. Beginning with the 2006 STEP, SPP and the RTWG have conducted annual analyses of Base Plan Upgrade cost allocation impacts to each Transmission Customer as required by Attachment J, and SPP has submitted regular reports to the Commission reporting on the results of these analyses, as the Commission directed.[13] SPP has also taken action when unintended consequences are discovered. For example, when a review of the 2006 STEP revealed unintended consequences resulting from the use of a "net change" MW-mile cost allocation analysis, SPP and its stakeholders promptly revised its zonal cost allocation to implement a "sum of positive impact" MW-mile allocation methodology to remedy the problem, and SPP filed the change for Commission approval.[14]

(b) Highway/Byway

In the submission of the Highway/Byway cost allocation methodology to FERC for approval in April 2010, SPP proposed additional Tariff provisions to: (1) require review of the Highway/Byway cost allocation methodology and allocation factors at least every three years (rather than five years, as existed under the previous Tariff provisions); (2) authorize the RSC to recommend any adjustments to cost allocation if the unintended consequences review shows an imbalanced cost allocation in one or more Zones; (3) require the MOPC and CAWG to define the analytical methods to be used and suggest adjustments to the RSC and the Board of Directors

[13] *See, e.g.*, Informational Report of Southwest Power Pool, Inc., Docket No. ER05-652-000 (June 1, 2009); Informational Report of Southwest Power Pool, Inc., Docket No. ER05-652-000 (Aug. 15, 2008).

[14] *See* Submission of Revisions to Open Access Transmission Tariff of Southwest Power Pool, Inc., Docket No. ER07-1248-000 (August 3, 2007). The revised MW-mile calculation was accepted by the Commission on October 18, 2007. *Sw. Power Pool Inc.*, Letter Order, Docket Nos. ER07-1248-000 and -001 (Oct. 18, 2007).

regarding any imbalance in zonal cost allocation in the SPP Region; and (4) permit any Member company, starting in 2015, to seek relief from the MOPC if it believes that it has been allocated an imbalanced amount of costs under the Highway/Byway methodology.

Specifically, SPP revised Section III.D to require review of not only the allocation factors, but the regional allocation methodology, and to require review at least every three years rather than five years. SPP also proposed revisions to the language governing its review of the unintended consequences of the cost allocation of Base Plan Upgrades to each pricing Zone within the SPP Region to include more detail. SPP will share the results of its review with the RTWG, MOPC, and RSC, and will publish the results on its website. SPP will also request that the RSC provide any recommendations to adjust cost allocations if the results of the analysis show an imbalanced cost allocation in one or more Zones. SPP proposed revisions to allow Member companies (beginning in 2015) that believe they have been allocated an imbalanced portion of costs to seek relief from the MOPC. SPP also proposed several changes to Attachment O (discussed below) to enhance its unintended consequences review.

In addition, as discussed above, SPP proposed several revisions to Attachment O to address its unintended consequences review required by Attachment J. Specifically, SPP modifed provisions in Section VI.4 of Attachment O governing its "Analysis of Transmission Alternatives to Address Needs Identified in the Reliability Assessment" to require SPP to consider the costs and benefits in selecting potential solutions by requiring:

(1) SPP to review of the scope and assumptions of the analysis with the CAWG and Economic Studies Working Group ("ESWG");

(2) financial modeling based on a 40-year time frame (with the last 20 years provided by a terminal value);

(3) quantification of the benefits from dispatch savings, loss reductions, avoided projects, reductions in carbon emissions, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics developed by the ESWG;

(4) identification and quantification of the benefits from reliability improvements to the transmission system;

(5) inclusion of different scenarios to analyze sensitivities of load forecasts, wind generation levels, fuel prices, carbon prices, and other relevant factors;

(6) assessment of both the regional costs and benefits for the SPP Region and the net cost-benefit of each scenario on a zonal and state basis; and

(7) assessment of the net impact of the transmission plan developed in accordance with Attachment O on a typical residential customer.

These revisions provide significant specificity to the analysis of alternatives and facilitate the process of conducting the unintended consequences review required by Attachment J.

All of these revisions require SPP to review its cost allocation methodology more frequently to ensure that it remains appropriate and allocates costs and benefits properly across all Zones over time and provide for more rigorous unintended consequences review than was conducted under SPP's pre-Highway/Byway Attachment J. All of the revisions proposed by SPP related to Unintended Consequences were accepted by the Commission in its June 17, 2010 order.[15]

(c) Integrated Transmission Planning

In the new SPP planning paradigm known as the ITP process, impacts of unintended consequences remains an important concern. The review contained in Section 16.7 of the 2010

[15] A copy of the FERC Order is available at: http://www.spp.org/publications/2010-06-17_Order%20-%20Highway-Byway%20Cost%20Allocation_ER10-1069.pdf.

Integrated Transmission Plan 20-Year Assessment Report ("ITP20 Report")[16] is staff's first attempt at such an effort and, while introductory and preliminary at best, should grow in quality and content over time with input from stakeholders and further development of tools used in the analysis. Now, and as ITP planning matures, it is possible to begin analyzing the costs and benefits of the added facilities, addressing rate impacts, and mitigating any unintended consequences.

Section III. D. of Attachment J to the Tariff prescribes a formal review of the base plan cost allocation methodology, including determination of any imbalanced zonal cost allocation. The discussion of benefits and costs in the ITP20 Report is **not** that review. Rather, the discussion is a preliminary, general examination of the issue of unintended consequences in an ITP20 context.

The preliminary unintended consequences assessment for 2010 ITP20 determined any deviation of the zonal distribution of production cost savings and other benefits through installation of the upgrades (benefits) from the corresponding allocation of the upgrade cost (cost). The analysis in Table A9.2 of the 2010 ITP20 Report identifies any current imbalance in the distribution of cost and benefit associated with known upgrades committed to date that are expected to exist in 2030 prior to addition of the ITP20 upgrades. It sets out the degree to which installation of the ITP20 upgrades result in a better balance of accumulated costs and benefits for each zone. Analysis of cost is a relatively straightforward endeavor. Determining zonal cost impacts from adding one or more upgrades involves distributing the associated revenue requirement to the zones pursuant to the cost allocation provisions of the OATT. The analysis of benefit, by zone, can be calculated for a discrete set of upgrades and has been completed for the

[16] A draft of the ITP20 Report, which includes the tables discussed herein, is available at: http://www.spp.org/section.asp?pageID=128.

Robust Plan 1 upgrade set. The benefits amounts are derived from production cost savings, reliability upgrade deferrals or displacements and decreased losses. These benefit amounts exclude wind, gas price and local economic benefit categories.

Table A9.2 first depicts estimates of costs and benefits at year 2030 associated with all previously-committed upgrades, excluding costs and benefits of the 2010 ITP20 upgrades. A benefit-to-cost ratio for that circumstance is computed for each zone. Then the cumulative 2030 revenue requirement, including the first year revenue requirement of the 2010 ITP20 upgrades, is depicted. Only the projected adjusted production cost savings are considered zonal benefits and included in the cumulative zonal benefit, and the resultant benefit to cost ratio for that circumstance is computed for each zone.

The benefit to cost characteristics for American Electric Power Service Corporation, Nebraska Public Power District, Omaha Public Power District and Lincoln Electric System are substantially improved by the addition of the 2010 ITP20 upgrades.

Since the analysis shows four zones that continue to reflect a cumulative benefit-to-cost ratio less than one, a theoretical set of transfer payments are calculated to adjust benefits by zone to result in a minimum benefit-to-cost ratio of 1 for all zones. These transfers are similar in magnitude to the transfers required for the Balanced Portfolio project set, adjusted for inflation.

(d) Summary

The above generalizations are rough estimates of the expected impacts if Robust Plan 1 upgrades were installed. Rate impacts and unintended consequences will remain a concern and should continue to be investigated in the ITP process.

Exhibit 1

SPP Staff Whitepapers Presented at

Strategic Planning Committee Meeting on December 3, 2010

SPP Roles and Responsibilities

As SPP staff began to prepare the strawman drafts addressing the four motions adopted by the Regional State Committee ("RSC") on October 25, 2010, and assigned on October 26, 2010 by the SPP Board of Directors to the Strategic Planning Committee ("SPC") and the Transmission Working Group ("TWG"), it became apparent that the development and understanding of the strawman drafts would be advanced by a statement of the roles and responsibilities of SPP, the Transmission Owners and regulators in the planning and construction process.

The four motions assigned to SPP by the Board of Directors are as follows:

MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded. (SPC)

MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011. (SPC)

MOTION 3: RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200KV & above that are regionally funded. (TWG)

MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed. (SPC)

Roles and Responsibilities

With the advent of SPP as a Regional Transmission Organization ("RTO") and its evolution from reliability-only planning and Base-Plan funding to Balanced Portfolio to Integrated Transmission Planning and Highway/Byway cost allocation, local member utilities that are now purchasing transmission service from SPP to serve their loads are becoming increasingly liable for rates imposed by a FERC-approved tariff for transmission projects constructed by other member utilities in other states. This situation inevitably creates greater regulatory complexity at the state level. SPP respects the desire of the state regulatory commissions, as expressed through the RSC, to explore the ramifications of this situation.

The role of SPP is not that of an arbiter of costs of its members. Section 3.3 of the Membership Agreement addresses SPP's and the Transmission Owner's respective roles and responsibilities regarding transmission planning and construction. Section 3.3 of the SPP Membership Agreement reads in total as follows:

(a) As part of its planning activities, SPP shall be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate state authorities, including the Member's governing board where it serves as that authority. Transmission Owner shall use due diligence to construct transmission facilities as directed by SPP in accordance with the OATT and this Agreement, subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals, including, as necessary, the Member's governing board where it serves as that authority. Such construction shall be performed in accordance with Good Utility Practice, applicable SPP Criteria, industry standards, Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements), and in accordance with all applicable requirements of federal or state regulatory authorities. Transmission Owner shall be fully compensated to the greatest extent permitted by FERC, or other regulatory authority for the costs of construction undertaken in accordance with the OATT.

(b) After a new transmission project has received the required approvals and been approved by SPP, SPP will direct the appropriate Transmission Owner(s) to begin implementation of the project. If the project forms a connection between facilities of a single Transmission Owner, that Transmission Owner will be designated to provide the new facilities. If the project forms a connection between facilities owned by multiple parties, all parties will be designated to provide their respective new facilities. The parties will agree among themselves as to how much of the project will be provided by each entity. If agreement cannot be reached, SPP will facilitate the ownership determination process.

(c) A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

These provisions acknowledge the recognized division of interests between the transmission planning function of SPP as the Transmission Provider and the financial and construction responsibilities and ownership interests of Transmission Owner(s). Attachment O, Section VI (1), of SPP's OATT reinforces the distinction in interests providing that:

> The Transmission Provider shall not build or own transmission facilities. The Transmission Provider, with input from the Transmission Owners and other stakeholders, shall designate in a timely manner within the SPP Transmission Expansion Plan ("STEP") one or more Transmission Owners to construct, own, and/or finance each project in the plan.

The functions of investing in transmission facilities and charging customers are within the management function of the local utilities, subject to the appropriate regulatory jurisdiction, including FERC and appropriate state regulatory authorities. Commonly, such jurisdiction is exercised via some combination of state siting or certificate authority and/or state and federal ratemaking authority. Prior to the advent of open-access transmission service and regional rates set by FERC for RTOs, each state regulatory authority generally set rates for bundled retail service, which included generation, transmission, and distribution service, based on costs incurred by the utility for construction and operation of that utility's facilities.

While the Transmission Owners in SPP have ceded their transmission planning responsibilities to SPP, they have not ceded their rights and responsibilities related to construction of transmission facilities or their rights to establish their revenue requirements to SPP. The processes of project cost estimation and project management are matters to be addressed by the Transmission Owners' through their internal processes and interactions with appropriate regulatory authorities.

The current discussion, which has arisen as a result of the escalation of some transmission cost estimates for Priority Projects, is a product of the increased openness and transparency of the SPP planning processes and the regionalization of cost allocation. In the past, transmission cost estimates would have tended to remain internal to each member utility, subject only to the utility's internal review and any applicable obligations to its regulatory authorities. Adjustments in cost estimates "prior to a spade of earth being turned" would have been handled completely within the utility's management and processes. Estimate modifications may not have been available throughout the project development process. SPP's Attachment O Transmission Planning Process, Balanced Portfolio, Integrated Transmission Planning Process ("ITP") and Priority Projects, provide additional transparency into the early stages of the transmission planning process.

By definition, SPP's transmission planning process, including the ITP process, means that each new project is part of an integrated whole. While each project has unique characteristics, it is the combination of the projects that creates the regional benefits. Modifications to a planned group of projects will necessarily impact the operation of the transmission system. Service commitments are made based on available capacity shown from models of the transmission system at the time of the request. As project commitments and service commitments are made, the models are updated to reflect those commitments. Changes to the model change the projected model flows on individual lines. Removal of a line from the model will affect flows on other lines in the model.

For SPP to function in accordance with its responsibilities and authorities, the interests and responsibilities of all stakeholders must be understood and respected: SPP to provide a transparent regional transmission planning process; the Transmission Owners to construct and own transmission facilities; and the FERC and state regulatory authorities to regulate within their statutory authority. As previously discussed, the regulatory role has been exercised via some combination of state siting or certificate authority and/or federal and state ratemaking authority. State regulatory authorities typically possess the authority to:

1. Disallow imprudent or unreasonable costs in a traditional ratemaking proceeding;
2. Impose conditions on siting approval or a certificate of public convenience and necessity that the utility provide periodic reports on the cost estimates of a particular project;
3. Intervene in another state's regulatory proceeding as an interested party;

4. Intervene before FERC in a rate case; and
5. Review and approve or reject a utility's Integrated Resource Plan;

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SPP can best serve the interests of stakeholders in addressing the issues raised in the RSC motions by maintaining its commitment to communication and transparency. While the cost estimation process must ultimately remain the responsibility of the Transmission Owner, SPP staff will structure procedures related to project screening, cost/benefit analyses, etc., before turning to the Transmission Owners to develop the final cost estimates to be used prior to the issuance of NTCs and the commencement of project tracking. By promoting a better understanding of SPP's roles and responsibilities and the roles and responsibilities of SPP's diverse stakeholders, it will be easier to determine appropriate avenues for accomplishing the goals of the RSC motions and to develop appropriate expectations of SPP staff, its member Transmission Owners and other stakeholders. To that end, SPP staff is proposing to the SPC strawman drafts to address the four motions made by the Regional State Committee and directed to SPP for consideration.

Cost Overruns/Underruns Whitepaper

RSC Motion 1

During their Monday, October 25th, 2010 meeting, the RSC passed the following as Motion 1:

> **RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.**

Introduction

SPP's current project tracking process tracks costs and in-service dates of projects that have received a Notification to Construct (NTC) from SPP staff. To ensure that cost overruns/underruns are monitored with sufficient scrutiny, some modification to the current process is needed.

Current Project Tracking Procedure

When a project receives an NTC it is entered into the Project Tracking process. The Transmission Owner (TO) is required to submit quarterly updates of cost estimates and the expected in-service date. These updates are incorporated into a quarterly report that is submitted to the Board of Directors/Members Committee (BOD/MC), the Markets and Operations Policy Committee (MOPC), and the Regional State Committee (RSC). In accordance with the guidelines provided in the NTC Whitepaper approved in early 2010, cost estimates that have increased by more than 20% since the previous estimate require the project developers to submit justification for the variance.

NTC Project Estimates

To make the Project Tracking process more rigorous, several enhancements are offered here. The cost estimate included in an NTC is the stage 3 estimate; this will be the NTC Project Estimate (NPE) for the project. The NPE will become the initial cost estimate baseline for project tracking. The baseline is the point from which the variance will be measured. This number will be the basis throughout the project tracking process to be compared with estimate updates to determine overrun/underrun percentages.

Process Enhancements

A developer who has a project whose NPE exceeds $5,000,000 will be required to submit updates on a monthly basis for that project. A developer who has a project with a cost estimate which is under $5,000,000 will be required to submit updates on a quarterly basis. Monthly and quarterly updates should consist of a detailed cost breakdown which mirrors the original Standardized Cost Application (SCA)[1]. The report will include a comments column and any changes to an estimate must be

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[1] For more information regarding the SCP reference the white paper on Cost Estimates.

accompanied by a comment explaining the change. If the cost variance for a project exceeds +/- 25%[2] of the baseline, then the project will be reviewed by a new working group, Project Cost Working Group (PCWG), or assigned to an existing working group.

PCWG Review

The PCWG will only reevaluate projects whose costs have changed outside the allowable variance. The reevaluation by the PCWG will be based on data and information from both the TO and SPP staff. The PCWG will be provided with the original SCA, monthly project tracking data updates, and any comments from SPP staff or the TO related to the cost revisions. Comments from the TO should include relevant information regarding any sunk costs, an explanation for the cost overruns/underruns, and comments as to why the project should or should not continue forward. The reevaluation will include an analysis of the cost changes and whether these changes are reasonable and appropriate for regional funding. The PCWG will also recommend if a restudy of a project is required.

There are instances where resetting the baseline will be prudent as it would not be reasonable for a project to be automatically flagged for review every month following an overrun/underrun that had been previously reviewed and accepted. The PCWG will determine if and when to reset the baseline cost estimate. If a baseline cost estimate is reset, the NPE will still be retained in the monitoring tool.

PCWG Report

The PCWG will submit a quarterly report to the SPP RSC and BOD/MC regarding the reevaluated projects. This report will include the rationale for each cost change as well as comments from the PCWG stating whether the cost change is reasonable and appropriate for regional funding. If the PCWG states the cost change is either not reasonable and/or not appropriate for regional funding, the PCWG will include a recommendation.

Restudy Determination

The PCWG will be tasked with determining if a restudy is required. A change in cost may not impact the benefits a project provides. However, a cost could change by such a magnitude that other alternatives would have been considered in its place. In that instance, a study may be required to review other projects which were previously discarded since they had a higher cost than the reviewed project but now have a lower cost. SPP staff will provide the PCWG with information to consider while determining the necessity of the restudy. This information will include a list of project alternatives which were reviewed during the original study, the cost of the alternatives, and a review of the resources necessary to complete the restudy. All of the following criteria must be met in order for restudy to be required:

- Latest cost estimate must exceed $10,000,000

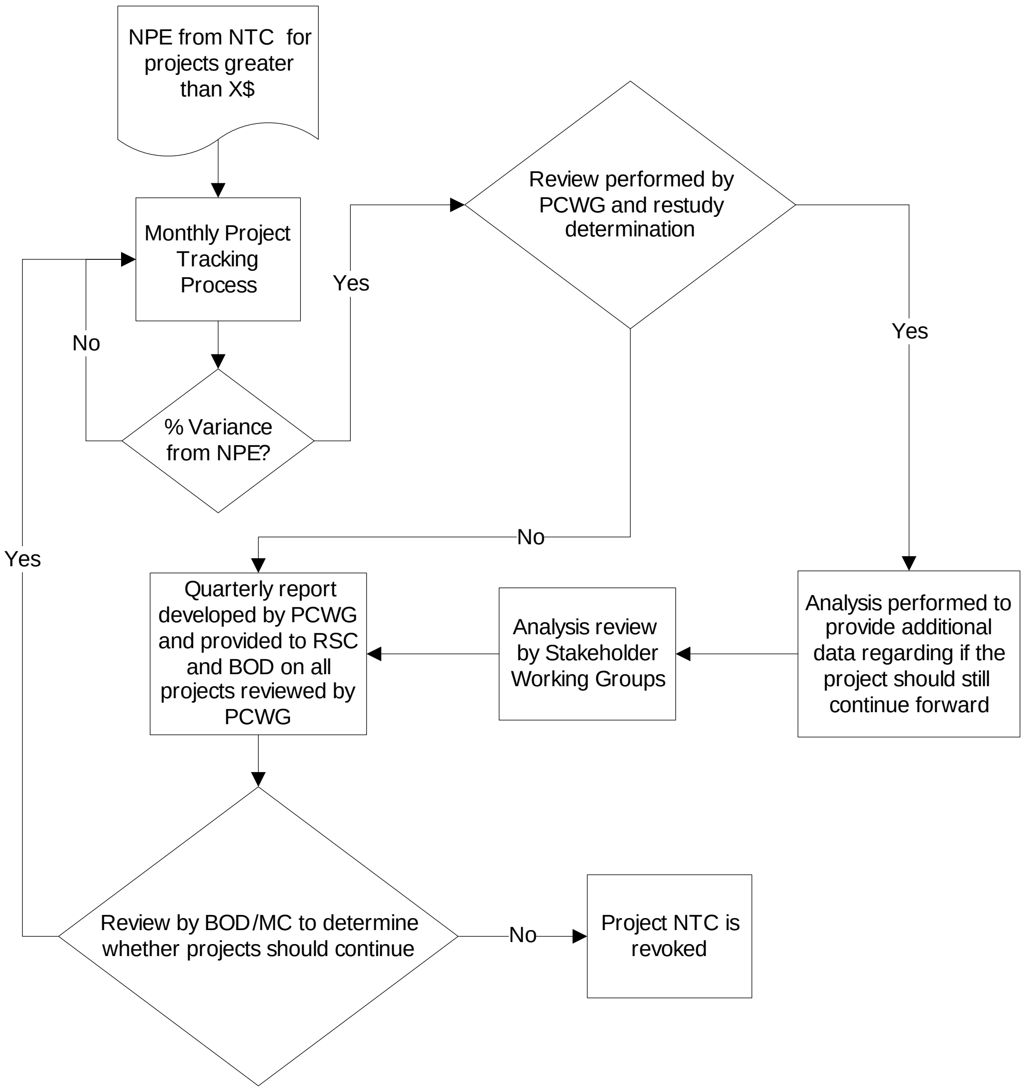
[2] This is the same percentage that is the allowable variance for the Stage 3 cost estimate in the Cost Estimate White Paper.

- If Benefit/Cost (B/C) ratio was a rationale for the project, the B/C must be less than 1
- Actual construction of the project has not yet started
- The cost must have increased 30% from the baseline

Restudy if Required

If the PCWG believes a project should be restudied, SPP staff will develop a study scope which will be approved by the TWG or ESWG. The study analysis and results would follow the typical stakeholder process by moving through the appropriate stakeholder working groups and finally to the BOD for a final decision. The BOD/MC will decide whether the original NTC will be revoked or if the project will continue forward. If the NTC is revoked by the BOD/MC, and the SPP staff analysis identified an acceptable alternative, the BOD/MC could then issue an NTC for the alternative project.

Project Tracking Flow Chart



Illustrative Monthly Cost Update Example

Project Description				
Estimate Provider				
Estimate Date				
In-Service Date				
	Details	**Initial Cost Estimate**	**Updated Cost Estimate**	**Comments**
Conductor	Size			
	Design			
	Electrical Capacity (amps)			
	Other			
Structure	Type			
	Material			
	Base			
	NESC Assumption			
	Dead Ends			
	Underbuild			
Substation	Transformers			
	Breaker Scheme			
	Protection Scheme			
	Voltage Control			
Construction Labor	Amount			
Right of Way (ROW)	ROW (Mileage)			
	ROW Condition (e.g., Urban, Rural, etc.)			
Eng. Design, Project Management, Permitting	Permitting/Certifications			
	Escalation Rate			
	Eng. Design/Proj. Mang.			
Loadings	Type 1			
Other Cost	Other Cost Factor Notes			
Total Cost				

RSC Motion 2: The Novation Process

Both the SPP Membership Agreement and Attachment O to SPP's OATT provide a designated Transmission Owner the unfettered right to assign the construction and ownership of a transmission project to a third party. Section 3.3(c) of the SPP Membership Agreement provides in part:

> A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

Section VI(6) of Attachment O of SPP's OATT provides, in relevant part:

> A Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the [entity having the following] qualifications . . . .
>
> i) Entities that have obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where the project is located,
>
> ii) Entities that meet the creditworthiness requirements of the Transmission Provider,
>
> iii) Entities that have signed or are capable and willing to sign the SPP Membership Agreement as a Transmission Owner upon the selection of its proposal to construct and own the project, and
>
> iv) Entities that meet such other technical, financial and managerial qualifications as are specified in the Transmission Provider's business practices.

For purposes of understanding roles and responsibilities related to the construction and ownership of transmission facilities, it is important to understand the distinction between assignment of a project and novation of a project. If a designated Transmission Owner cannot or does not want to construct a transmission project, there are two options available: assignment and novation. An assignment allows the designated Transmission Owner to transfer responsibility for construction of the project, but does not relieve the designated Transmission Owner of the financial or legal obligation to construct the project. SPP will continue to hold the designated Transmission Owner financially and legally responsible for timely construction of the project in accordance with the NTC. In contrast, a novation allows the designated Transmission Owner to transfer all legal and financial responsibility for the timely construction of the project to an existing Transmission Owner or an entity who will become qualified under SPP's process and become a Transmission Owner under SPP's OATT and Membership Agreement. SPP, through its stakeholder process, developed and documented a process for determining if an entity not currently an SPP Transmission Owner is qualified to become a Transmission Owner in SPP. That document is attached as an exhibit to this strawman. This process document is final in its form, but it is going to continually evolve as SPP develops more experience in using the process and addressing any issues or concerns that may arise from the process.

FERC accepted this process and the corresponding form of agreement, finding it was consistent with the SPP Membership Agreement, SPP's OATT and the filed rate doctrine, and would encourage third-party participation in SPP's transmission planning and construction and facilitate timely construction of needed transmission upgrades.

Reasons for assignment or novation

Numerous factors can result in a decision by a designated Transmission Owner to assign or novate a transmission project. These can include, but are not limited to, funding or financing limitations, increased costs of financing, and inability to timely construct the project.

SPP has issued NTCs for assigned a number of large 345 kV projects to smaller Transmission Owners, several of which happen to be RUS borrowers. As a general matter, the RUS denies loans that comprise an undue risk to a borrowing cooperative, i.e., loans that are unusually large or that are for purposes that are not normally undertaken by the cooperative for its own power supply purposes. The availability of a loan also depends upon congressional appropriations that are sufficient to meet RUS' funding plans. Consequently, the availability of an RUS loan may not be known for a year or more after a request is made and the loan may not actually be funded for two years or more after the request. These factors make the availability of RUS funding highly uncertain for large regional transmission projects. As an alternative to RUS borrowing, cooperatives are able to finance projects with private capital. RUS borrowers have typically mortgaged all of their facilities to the RUS to securitize their RUS loans. In order to fund a new project with private capital, RUS borrowers must implement a lien accommodation with the RUS to exempt the privately financed facilities from the RUS lien. This accommodation, if successfully achieved, typically takes a number of months to achieve. Private financing can be expected to cost at least two to three hundred basis points more than a RUS loan. Accordingly, the expectations that SPP's smaller Transmission Owners can make timely commitments to construct projects directed to them for construction at a cost reflecting their historic carrying charge rates have not proven to be realistic.

FERC Incentives

In response to the Energy Policy Act of 2005, FERC issued Order No. 679[1] implementing new policies regarding Transmission Owners' cost of service. FERC explained its rationale for providing incentives to Transmission Owners in setting rates:

> 25. These challenges and risks [associated with siting large new transmission projects] are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind currents), not simply on a "local" basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be "obligated" to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability. Our policies also must encourage all other needed transmission investments, whether they are regional or local, designed to improve reliability or to lower the delivered cost of power.
>
> 26. To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment. The Final Rule identifies several policies that should be adjusted, where appropriate on the facts of a particular case, to encourage new transmission investment or otherwise remove impediments to such investment. Although each reform adopted by the Final Rule constitutes an "incentive" as that term is used by section 219, this label has caused some confusion in the comments. It is true that our reforms adopted in the Final Rule provide "incentives" to construct new transmission, but they do not constitute an "incentive" in the sense of a "bonus" for good behavior. Rather, as we explain below, each will be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case and

[1] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,222, *order on reh'g*, Order No. 679-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

considering the fact that our traditional policies have not adequately encouraged the construction of new transmission.[2]

Among other things, FERC Order No. 679 allowed Transmission Owners to propose to include 100% of prudently-incurred Construction Work in Progress (CWIP) in rate base, thereby permitting Transmission Owners to avoid accounting for and collecting a return on and a return of Allowances for Funds Used During Construction (AFUDC), to permit higher returns on equity which in turn affects the Net Plant Carrying Charge (NPCC), and to permit a hypothetical capital structure.

FERC explained that it adopted the CWIP incentive because recovery of 100% of CWIP in rate base relieves "pressures on [utility] finances caused by transmission development programs" and provides "up-front regulatory certainty" and "improved cash flow[s]" for utilities and rate stability for customers.[3] FERC also stressed that CWIP recovery provides utilities "a higher credit rating and lower cost of capital, thus benefiting customers."[4] A higher credit rating and lower cost of capital makes it cheaper and easier for a utility to attract capital investment and borrow money to construct facilities, which benefits customers because the utility has fewer costs to recover from customers for new facilities.[5] Pursuant to Order No. 679, FERC has approved CWIP in rate base because it helps transmission projects stay on schedule, it offers a prompt return on investment, it improves utility cash flow, it enhances the utilities' credit quality and debt ratings,[6] and it results in better rate stability for customers.[7] FERC found that including CWIP in rate base passes on costs to customers during the construction period, which raises prices to customers earlier. The rise in prices results in reduction in customer demand, which allows the utility to avoid investing in unnecessary capacity expansion. Based on this logic, FERC found that "CWIP will generally allow utilities to pursue least *total* cost strategies to meeting their customers' electric power demands,"[8] which results in cost savings for customers.

FERC incentives are available to those jurisdictional utilities that seek permission for and justify the need for the incentive. Furthermore, because FERC required utilities seeking CWIP recovery to submit additional information about their construction programs, the recovery of CWIP allows FERC the "opportunity to review and judge the prudence of costs as those costs are incurred and claimed in rate

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2 Order No. 679 at PP 25, 26.

3 Order No. 679 at P 115.

4 *Id*. In the comments supporting FERC's notice of proposed rulemaking prior to Order No. 679, parties stated that the CWIP incentive allows the utility to balance the short and long-term impact on rates, and avoid rate shock on customers. *See e.g.*, Comments of San Diego Gas & Electric Company, Docket No. RM06-4-000, at 15 (Jan 11, 2006) ("Including CWIP in rate base instead of accruing allowance for funds used during construction will increase short-term rates during the construction period but reduce long-term rates once the project goes into commercial service.").

5 *See* Order No. 679 at 115.

6 *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 6 (2008); *see also id.* at P 42 (FERC approved PPL's request to recover 100% of CWIP in rate base because FERC found that the incentive " enhance[s] [PPL's] cash flow, reduce[s] interest expense, assist[s] Petitioners with financing, and improve[s] Petitioners' coverage ratios used by rating agencies to determine credit quality by replacing non-cash AFUDC with cash earnings…[t]his, in turn, will reduce the risk of a down grade in Petitioners' debt ratings."); *see also ITC Great Plains, LLC*, 126 FERC ¶ 61,223, at PP 80-82 (2009); *Otter Tail Power Co.*, 129 FERC ¶ 61,287, at PP 32-33 (2009); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284, at PP 57-61 (2007).

7 *See Green Power Express LP*, 127 FERC ¶ 61,031, at P 67 (2009); *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 42 (2008) ("By allowing CWIP for the Project, the rate impact of the Project can be spread over the entire construction period and will help consumers avoid a return on and of capitalized AFUDC.").

8 *Id*. at 24,331.

base, rather than at a later point in time when a project is completed or abandoned and a potentially unwise investment has already been made."[9] Therefore, another benefit of CWIP is a regulatory agency's ability to review CWIP expenses to determine the prudence of the utilities' investments as they are incurred, which protects customers from imprudent costs

To date within SPP, FERC has approved rates including CWIP only for transcos, i.e., ITC-Great Plains, Prairie Wind, and Tall Grass. SPP's analysis of the projects novated to ITC-Great Plains and proposed to be novated to Prairie Wind has demonstrated that, for the same cost of capital, the cost of CWIP and AFUDC are essentially the same over time. The primary benefit of CWIP to the builder is that capital markets perceive less risk in funding projects receiving CWIP treatment in rates and consequently should fund projects eligible for CWIP at a lower cost of capital than an AFUDC only project. SPP has not analyzed the effect of CWIP treatment on a project's cost of capital. While holding cost of capital equivalent, SPP has analyzed the effect of CWIP's increased short-term rate impact versus AFUDC's increased long-term rate impact and has found them to be approximately rate neutral when viewed from the perspective of the present value to the transmission customer. To the extent that CWIP rate treatment of a project does result in a lower cost of capital than AFUDC would, SPP believes that CWIP will provide benefit to customers based on SPP's conclusion that the CWIP is otherwise equivalent to AFUDC.

Creating a definitive side-by-side comparison of the impacts of rate-making factors such as NPCC, CWIP, and AFUDC would be challenging for several reasons:

1. There is no adequate baseline for a comparison, as it may not be financially feasible for the original designated Transmission Owner to build the project, at least not at its traditional cost of service. The original designated Transmission Owner that decides to assign or novate a project may not deem it necessary to estimate the project cost.
2. The various cost components are interrelated. Neither SPP, the original designated Transmission Owner, nor a third-party builder, is able to precisely determine its financing costs in the project estimation phase.
3. The final rate is dependent on a FERC determination regarding the justness and reasonableness of the appropriate incentives.
4. The rate impact will depend on the Transmission Owner to which the project is assigned.

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Conclusion

In an effort to address the concerns raised by the Motions from the RSC, SPP Staff suggests the solution is multi-faceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:

(1) SPP will provide proposed Novations and supporting analysis to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC.

(2) Staff will increase efforts to communicate with state commissions and state commission staff members about how the regional planning and cost allocation processes work, and more specifically

9 Order No. 298 at 30,515.

how and when estimates for transmission projects are requested by SPP and provided by Transmission Owners to SPP, including opportunities for adjustments.

SPP also suggests increased communication between jurisdictional transmission owners and state commissions might result in a better understanding of the Transmission Owners' processes for development of cost estimates and causes for variances in cost estimates.

Design and Construction Standards Whitepaper

RSC Motion 3

RSC recommends that SPP consider establishing design and construction standards for transmission projects at 200kv and above that are regionally funded.

Purpose

Provide a consistent and economic construction standard that can be implemented by all transmission owners and builders on the SPP transmission system.

Initial Proposal

To bring uniformity and economies of scale to regionally funded transmission projects, SPP will develop and maintain design and construction standards. The effort will provide consistency in the bulk transmission system. It also enhances reliability and reduces compatibility issues by having standard components used by all builders of the transmission system. Use of the same transmission protection standards eliminates any compatibility issues and ultimately increases reliability of the system. SPP will establish these standards as a result of a collaborative effort based upon the best practices being followed by members. The final draft of the standards will be approved by Transmission Working Group (TWG), followed by the Markets and Operations Policy Committee (MOPC). A long-term goal is to better manage construction costs. The initial focus of this task will be on the components that have the greatest variability in cost. The major components suggested for establishment of regional standards are detailed in the list below.

Though construction cost for transmission projects vary based upon location and other factors, establishing regional construction standards on the basis of best practices can provide guidelines and set expectations for construction standards that may be considered on a regional basis. These include:

- Conductor size
- Minimum ampacity value
- Fiber optic ground wire construction standards
- Structure/wooden pole construction specifications
- Foundation construction standards
- Substation control room construction standards
- Insulation and insulation hardware construction specifications

Interpretation of Standards and Tracking

SPP staff will be responsible for interpretation and application of regional standards and will track projects to ensure regional standards are being followed for regionally funded projects.

In some special circumstances, it may be necessary to deviate from the regional standard. Any requests for deviation/exception to the regional standard will need to be submitted to SPP staff for approval.

Example of Transmission and Substation Design Standard

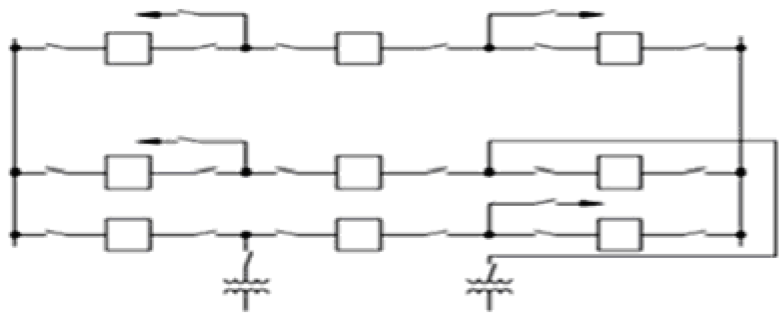
Breaker Configuration

Each new substation 230 kV and above should have an initial one-line of the substation and ultimate one-line of the substation. SPP staff should review the initial and ultimate substation arrangements. The SPP staff review should ensure substations are designed to accommodate future expansion of the EHV system. The following table lists the basic design for substation arrangements. The substation should be designed to accommodate the ultimate substation arrangement. This includes the purchase of land to accommodate the ultimate substation.

Voltage	Number of terminals	Substation Arrangement
230 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four	Ring Bus
	Five	Ring Bus
	Six	Ring Bus
	Seven or greater	Breaker and a half
345 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Ring Bus
765 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Breaker and a half

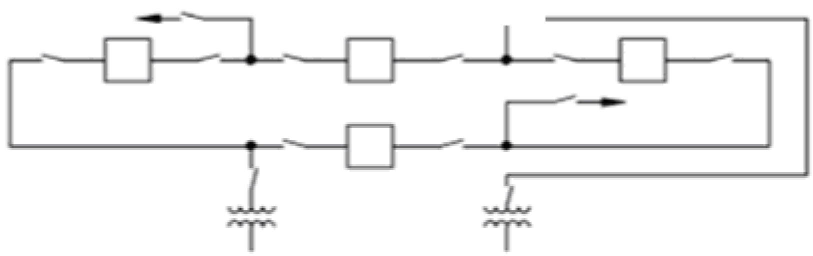
The following drawings show typical breaker arrangement for ring bus and breaker and a half.

Breaker-and-a-Half



Typical One-Line Diagram

Ring Bus



Typical One-Line Diagram

Terminal Equipment Minimum Rating

Minimum terminal rating substation equipment may be as follows:

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Transmission Line Design

The transmission line strength needed depends on several factors including geographic location, weather conditions, overhead ground wire and support structures of the line.

When selecting the appropiate design load, the engineer designing the transmission line should evaluate the climatic conditions and previous line operation experience. The National Electrical Safety Code (NESC) indicates the structure clearence requirements and component strength. All of these factors need to be considered in the transmission line design. The design engineer should complete an economic study to determine structure configuration and type (wood, steel or prestressed concrete). The economic structure should be selected. Exceptions to the economic structures should be reviewed by SPP staff.

Minimum Conductor sizing

SPP Criteria 12.2 addresses rating for transmission circuits. Minimum ampere rating for 230 kV and above transmission circuits are noted below. Any exceptions must be proposed and approved through the appropriate SPP process.

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Cost Estimate Whitepaper

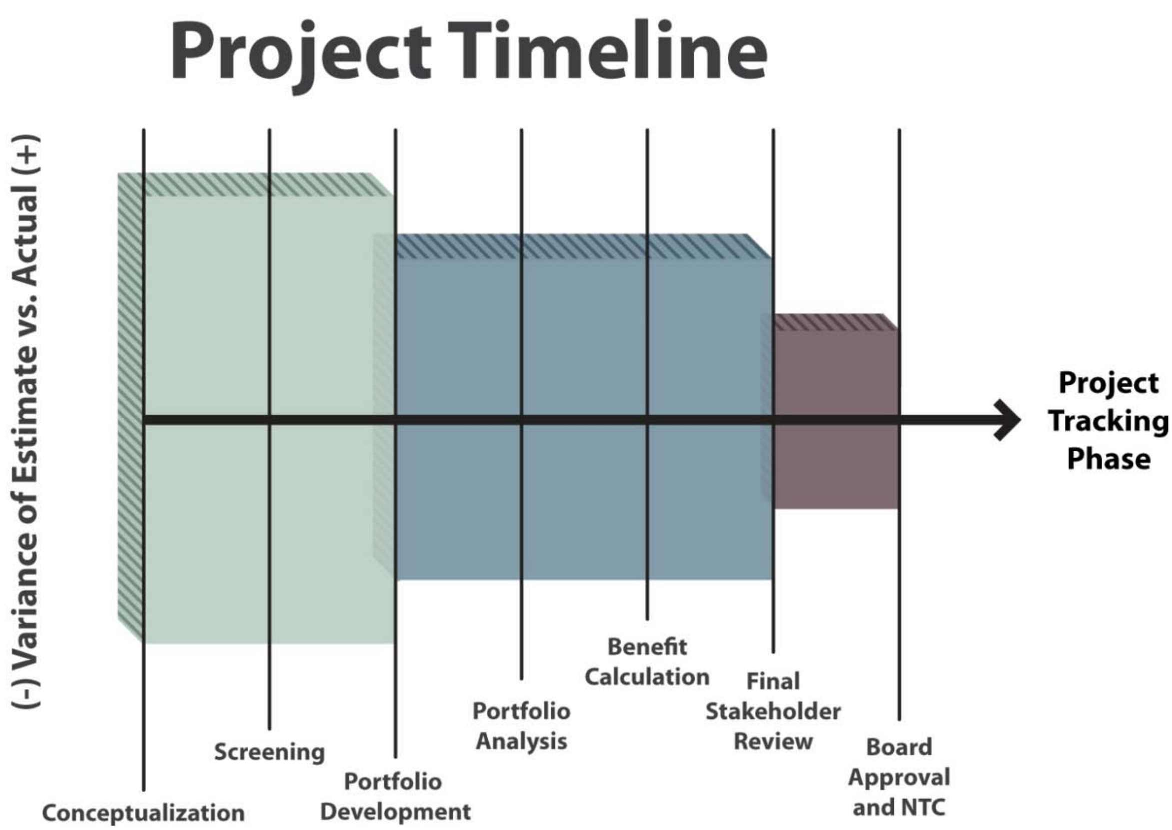
RSC Motion 4

During their Monday, October 25th, 2010 meeting, the RSC passed the following as Motion 4:

> **SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.**

Introduction

To ensure consistency in the development of cost estimates, SPP staff and stakeholders will create a standardized and transparent method for generating estimates. To allow estimates to evolve and become more refined as projects move from concept to construction, there will be multiple points in the planning process where cost estimates will be updated and increasingly higher levels of accuracy will be required. The Project Timeline illustration below shows how the planning process is broken into three stages. Each of these stages will have progressively tighter requirements on cost estimate accuracy and detail of data.



Stage 1

When projects are first conceived, cost estimates will be developed by SPP staff using a generic cost estimate tool. The tool will be developed in conjunction with the Transmission Working Group (TWG). The estimating tool will include generic cost data such as cost per mile for specific voltage levels, substation cost estimates, and cost modifiers for different regions, terrain, urban/rural, etc. This will allow estimates to be easily developed for the purpose of screening large numbers of potential projects and selecting suitable candidates for more detailed study. The simplified example below shows how a cost estimation tool might be developed. To estimate the cost of a project, the cost/mile of conductor and right of way (ROW) for a particular voltage class would be multiplied by the line length. Then the estimated cost would be multiplied by the applicable ROW multipliers to account for factors that can affect the cost of line construction. Finally the substation costs would be calculated and added to the total project cost estimate.

Simplified Illustrative Example

	Conductor/Structure Cost per Mile	ROW Cost per Mile
115	$	$
230	$$	$$
345	$$$	$$$

	ROW Multipliers
Urban	1.5
Rural	0.8
Plains	0.8
Mountains	1.5

	Substation Adder
Breaker	$
Xfer	$
New Sub	$

The output of the tool will be a table giving the total cost for each project being considered as well as all of the information that went into developing those. This will make it easy to see the variations in cost estimates between projects and why those variations exist. An example of this output is shown below

Simplified Illustrative Estimate Tool Output

Project Owner	Owner 1	Owner 2	Owner 3
Project Name	Project 1	Project 2	Project 3
Voltage	115	230	345
Length (miles)	10	50	100
Conductor/Structure Cost per Mile	$	$$	$$$
ROW Cost per Mile	$	$$	$$$
ROW Conditions	Rural/Plains	Urban/Plains	Rural/Mountains
ROW Multipliers	0.8*0.8	1.5*0.8	1.5*0.8
Substation Adders	$	$	$
Total Cost	$	$$$	$$$$$

On an annual basis SPP staff, in conjunction with the TWG, will update the cost data contained in the cost estimating tool. To assist with this effort, SPP staff will provide a report which gives an aggregate summary of final cost data collected in the project tracking process. [1] This will ensure that the cost estimate tool can be kept up-to-date and will help refine the tool to match actual final cost data.

Stage 2

Stage 2 begins after the initial project screening is completed and the list of potential projects has been narrowed to those most likely to be selected. It will be necessary for the incumbent Transmission Owner (TO) of each project to review and provide updates to the stage 1 cost estimates. This will help ensure that more accurate stakeholder provided data is used for the analysis and subsequent selection of projects. Differences between the stage 1 and stage 2 cost estimates must be accompanied by detailed explanations of the changes. This estimate is still considered to be a high level cost estimate; however, it is still expected to be within +/-50% variance from final construction cost.

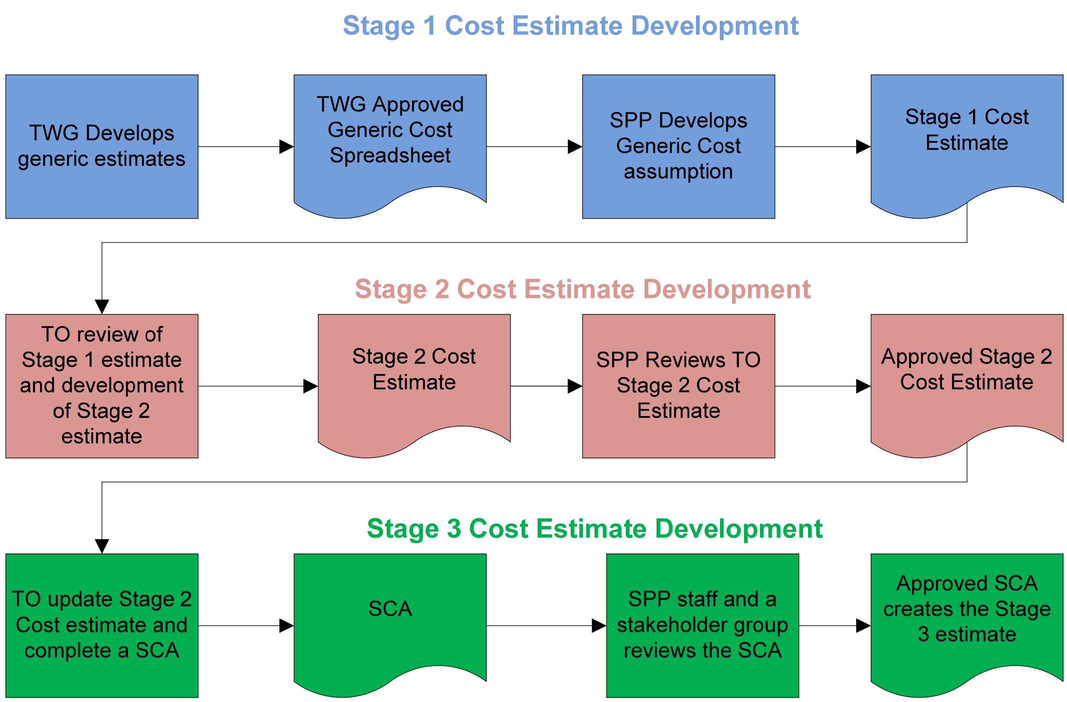
Stage 3

The stage 3 estimates will be required after the analysis is completed but before a final report is submitted to stakeholders for approval and NTC issuance. Projects that will receive an ATP instead of an NTC will not be required to have a stage 3 estimate. The incumbent TOs will be required to submit a completed Standardized Cost Application (SCA). This is expected to be a very detailed estimate and should be within +/-25% variance of final construction costs. The SCA will include among other things a detailed explanation of changes between the stage 2 and stage 3 estimates. All stage 3 SCAs will be reviewed by SPP staff.

[1] The project tracking process is explained in the Cost Overruns/Underruns White Paper.

Cost Estimate Flowchart

Following is a flowchart of the three stages in the standardized cost estimating process.



Standardized Cost Application

The SCA is used to ensure that all cost estimates are in a consistent format which provides the following benefits:

- Provides consistent format among all estimates
- Facilitates the project tracking process[2]
- Ensures the appropriate level of detail is required

At the end of this paper is an illustrative example of a cost application which contains some of the detail which may be developed for an SCA.

[2] The project tracking process is explained in the Cost Overruns/Underruns White Paper.

Illustrative Cost Application Example

Project Description			
Estimate Provider			
Estimate Date			
In-Service Date			
	Details	**Cost Estimate**	**Comments**
Conductor	Size		
	Design		
	Electrical Capacity (amps)		
	Other		
Structure	Type		
	Material		
	Base		
	NESC Assumption		
	Dead Ends		
	Underbuild		
Substations	Transformers		
	Breaker Scheme		
	Protection Scheme		
	Voltage Control		
Construction Labor	Amount		
Right of Way (ROW)	ROW (Mileage)		
	ROW Condition (e.g., Urban, Rural, etc.)		
Eng. Design, Project Management, Permitting	Permitting/Certifications		
	Escalation Rate		
	Eng. Design/Proj. Mang.		
Loadings	Type 1		
Other Cost	Other Cost Factor Notes		
Total Cost			

Exhibit 2

SPP Staff Presentations on RSC Recommendations

Presented at Strategic Planning Committee Meeting on December 3, 2010

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SPP Response to RSC Motions

Background

1. Priority Projects update provided to RSC and SPP BOD October 25-26, 2010
2. Updated report showed individual project cost estimate increases/decreases
3. Priority Projects cost estimates have increased a total of 24% or $217,000,000
4. RSC expressed concern over increases and presented four motions to SPP to address

RSC Motions

- RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
- RSC recommends that SPP review the Novation Process and report to the RSC by April 2011.
- RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200kV & above that are regionally funded.
- SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.

Roles and Responsibilities

Section 3.3, SPP Membership Agreement

- SPP is responsible for planning and for directing or arranging necessary transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service
- SPP will direct the appropriate Transmission Owners (TO) to being implementation of projects upon approval of the projects
- SPP will solicit and evaluate proposals and select a replacement where a designated TO cannot or does not implement project timely

SPP OATT – Attachment O, Section VI (1)

- SPP shall not build or own transmission facilities
- SPP designates timely TOs to construct, own and/or finance each project in the SPP Transmission Expansion Plan

Traditional process for transmission project cost estimates

- Project cost estimation and project management addressed by each TO through their internal processes
- Adjustments to cost estimates prior to “a spade of earth being turned” would have remained internal to the TO

Today: RTOs and Regional Cost Allocation

- SPP's open and transparent planning processes provide more information earlier than ever before
- Regional cost allocation has increased awareness of the value and necessity of accurate project cost estimation
- ITP planning process

  Each project is part of an integrated whole

  The combination of the projects provides the regional benefits

  Changes to one piece of the whole affects the whole

Role of State Regulatory Authorities

- Disallow imprudent or unreasonable costs
- Impose conditions on siting approval or CCN to require periodic reports on cost estimates of a project
- Intervene in another state's regulatory proceeding
- Intervene at FERC in rate cases
- Review and/or approve a utility's Integrated Resource Plan

Pieces of the Puzzle

- SPP – Responsible to provide a transparent regional transmission planning process
- SPP TOs – Responsible to construct and own transmission facilities
- SPP Regulators – Responsible to regulate within their statutory authority and construct

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Cost Overrun/Underrun Monitoring Proposal

SPP Staff

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Purpose

- Response to recent transmission project cost estimate increases after project approval
- Improvement of SPP's current Project Tracking
  - Mechanism to help control cost overruns/underruns
  - Provide greater transparency
  - Increase data sharing

SPP Project Tracking Prior to 2007

- Projects reported through Transmission Planning
  - Projects reported by type of planning activity
    - Contained project description, in-service date, cost estimate, and engineering data
  - In 2006 annual Expansion Plan presented to Market and Operations Committee (MOPC) with list of projects
  - In April 2007, first quarterly Project Tracking Report delivered to MOPC with Project Status
    - Complete
    - On schedule
    - Mitigation
    - Delayed

5

SPP

2007 - Strategic Planning Committee

- January 30, 2007 Strategic Plan approved by Board
  - Establish SPP Transmission Project Tracking process
    - Monitor STEP transmission projects
  - Develop quarterly tracking and reporting tool
  - Proactive support of members
    - Project approval
    - Siting
    - Cost recovery
  - Annual Report to BOD evaluating transmission projects

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SPP

SPP Project Tracking after Order 890

- Formal project tracking started with Order 890 in December 2007
  - Sections VIII.1 and VIII.3 of Order 890 ensure projects built on time or with acceptable mitigation plans
  - Established project reporting on a quarterly basis with emphasis on project status and time of completion
    - Supported efforts already underway from SPP Strategic Plan
  - Project Tracking Reports posted to SPP website

7

SPP

Current Project Tracking Process

- Notification to Construct (NTC)
  - Establishes commitments for each upgrade
- Active Project Tracking
  - Transmission Owners communicate progress quarterly on key components of active projects
    - Status, in service date, estimated cost, final cost
  - Quarterly Project Tracking Report produced
    - Executive Summary, project metrics for active portfolio
  - SPP provides analysis for changes in dates and estimated costs
  - Actions taken for cost increases and mitigations

8

SPP

Project Status

- Project Status enhanced
  - Previous reports limited on description of status

Green	On Schedule
Orange	Unknown
Red	Delayed

Footnotes:

S	Project On Schedule
D	Delayed *Note: Information on Deferred projects currently being solicited from the T.O.*
C	Cancelled
X	Project Complete

  - Since 2008, report statuses expanded with further explanation

COMPLETE	Complete.
ON SCHEDULE <4	On Schedule 4 Year Horizon.
ON SCHEDULE >4	On Schedule beyond 4 Year Horizon.
NTC- COMMITMENT WINDOW	NTC issued, still within the 90 day written commitment to construct window and no commitment received
MITIGATION	Behind schedule, interim mitigation provided or project may change but time permits the implementation of project.
RE-EVALUATION	Behind schedule, require re-evaluation due to anticipated load forecast changes.
DELAY- NO MITIGATION	Delayed beyond the RTO Determined need date and no mitigation plan provided

Estimated Cost

- Estimated Cost analyzed for change
  - Since late 2009 SPP tracks and verifies cost changes greater than 20% with Transmission Owner
    - Follows guidelines of NTC White Paper approved by members
  - SPP will add Original Cost Estimate to analysis in 4th quarter of 2010

Cost Change Letter Sent	NTC_ID	Project Name	Project Type	Previous Cost Estimate	Current Cost Estimate	Cost Change Percent
11/8/2010	20014	Line - Plymell - Pioneer Tap 115 kV	regional reliability	$3,200,000	$5,534,364	72.95%
11/8/2010	20079	Line - Pratt - St. John 115 kV rebuild	regional reliability	$9,239,000	$13,418,922	45.24%
	20091	Line - Allen - Lehigh Tap 69 kV	transmission service	$4,131,000	$4,900,000	18.62%
	20091	Line - Athens - Owl Creek 69 kV	transmission service	$2,227,000	$2,633,000	18.23%
	20086	XFR - Halstead South 138/69 kV Ckt 1	regional reliability	$1,400,000	$1,650,000	17.86%

Project Tracking Report

- **Project Tracking Report provides analysis and comparisons on project portfolio**
  - **Early Reports included a short Executive Summary and a list of outstanding projects**

SPP 4th Quarter 2007 Project Tracking Report

Executive Summary

1.No upgrades classified as (RED) in this summary.

#2. To date in 2007, SPP project owners have completed 125 miles of new or upgraded transmission and related equipment representing an investment of $116 million.

#3.14 upgrades have been completed this quarter. $ 7 million in transmission lines and facilities were added from Richards - Piedmont and ReinMiller – Tipton Ford.

#4. SPP is tracking the development of 70 upgrades currently requiring mitigation plans (YELLOW).

Project Tracking Report

- **Project Tracking Report more robust as members and executives require further information**

4th Quarter Projected Transmission Miles Complete				
Voltage	Number of Upgrades	New Miles	Reconductor Miles	Total Miles
69	4	0	22.18	22.18
115	9	111.4	13.02	124.42
138	5	14	12	26
161	5	0	0	0
230	0	0	0	0
345	0	0	0	0
Totals	23	125.4	47.2	172.6

Scheduled Complete Next Quarter	
First day of Quarter	Last Day of Quarter
[illegible]	[illegible]
Reliability	[illegible]
Reliability Non OATT	[illegible]
Zonal Reliability	[illegible]
Transmission Service	[illegible]
Generation Interconnect	[illegible]
Balanced Portfolio	[illegible]
Sponsored	[illegible]
Zonal Sponsored	[illegible]
Total	[illegible]

Scheduled Complete Next 12 Months	
First day of Reporting Year	Last Day of Reporting Year
[illegible]	[illegible]
Reliability	[illegible]
Reliability Non OATT	[illegible]
Zonal Reliability	[illegible]
Transmission Service	[illegible]
Generation Interconnect	[illegible]
Balanced Portfolio	[illegible]
Sponsored	[illegible]
Zonal Sponsored	[illegible]
Total	[illegible]

3rd Quarter 2010 Project Tracking Status

Top number is number of upgrades in category
Bottom number is estimated cost of upgrades in category

Upgrade Type	Total	Complete	On Schedule	On Schedule - Later in 10 yr Horizon (NTCs Issued)	Behind Schedule - With Mitigation	Behind Schedule - Without Mitigation	Withdrawn, Cancelled, blank, or within NTC Window
Reliability	312 $1,739,071,038	48 $198,906,254	80 $419,288,938	16 $178,225,254	145 $872,813,581	14 $50,093,466	9 $19,743,545
Transmission Service	77 $548,684,487	16 $27,806,325	28 $324,830,147	5 $28,732,500	10 $80,965,773	0 $0	18 $86,349,742
Generation Interconnect	17 $104,464,731	7 $19,064,731	8 $58,960,000	0 $0	1 $25,590,000	0 $0	1 $850,000
Balanced Portfolio	17 $837,064,596	0 $0	12 $618,023,096	4 $207,791,500	1 $11,250,000	0 $0	0 $0
High Priority	25 $1,144,856,481	0 $0	1 $842,847	24 $1,144,013,634	0 $0	0 $0	0 $0

Current Process Overview

- SPP Project Tracking has evolved with the change and growth in transmission projects
  - Order 890 formalized process
  - Quarterly updates with Transmission Owners, quarterly reporting to executives
  - Project Status initial focus, expanded to all aspects of projects including estimated and final costs
  - SPP continues to improve and update process for accuracy and deliverability of project data
    - Project Tracking Database implementation
    - Cost estimate and overrun white paper in development

13

SPP

Other Organizations' Processes

- CREZ
  - Detailed monthly reporting
  - Baseline starts 6 months after CCN approval
  - Cost increases are reviewed and must be reasonable to be included in their rate case with the PUCT
- ISO-NE
  - Transmission costs that exceed reasonable variance become localized costs
  - ISO-NE can request an update at random but requires three per year

SPP 14

Other Organizations' Processes

- NYISO
  - Risk profile included with cost estimate and is approved by NYISO working group
  - Risk profile addresses what parties are responsible for cost overruns, otherwise the cost remains with the developer
  - Quarterly updates
- MISO
  - Quarterly reporting
  - No enforcement mechanism

SPP 15

Proposed Process Improvements

- Baseline is the Stage 3 cost estimate used in the NTC called the NTC Project Estimate (NPE)
- Only projects with a cost over $5,000,000 will report monthly
- Projects with a cost less than $5,000,000 will report quarterly
- The update will be a detailed cost breakout which mirrors the Standardized Cost-Estimate Application (SCA)
- Updates required even if there is no change

SPP 16

Process Improvements (continued)

- NPE maintained throughout whole process for tracking purposes
- All cost estimate changes must be explained by the TO
- If overrun/underrun percentage exceeds 25% of the NPE, then project will be reviewed by Project Cost Working Group (PCWG)

Review Process

- All projects outside the 25% variance
- Relevant data provided to the PCWG
  - Original SCA, Monthly Reports, Comments from TO & SPP
- Inquiry into reasonability of cost increases
- PCWG decides if project needs to be restudied by SPP
- PCWG provides report to RSC and BOD quarterly
  - Report posted on SPP website

PCWG

- Meet monthly (via teleconference) to review project tracking updates
- Quarterly report from the PCWG provided to the RSC and BOD
- Report on reasonability of cost overruns/underruns, project delays, impacts, etc.
- Determines if there is a need to restudy the project

SPP 19

PCWG Report to RSC and BOD

- Issues results of inquiry into reasonability of cost increases
- Provides comment as to if the overruns/underruns should be regionalized
- Recommends if a new baseline for the project cost is appropriate
  - Original NPE will still be maintained

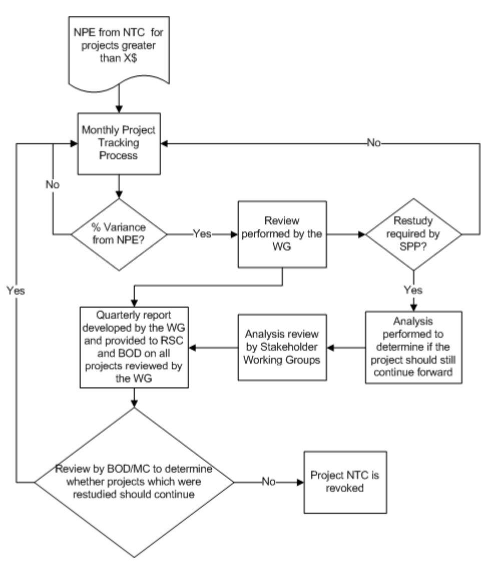
SPP 20

BOD Action

- Multiple options for projects whose costs exceed the allowable variance
- Revoke NTC
- Allocate overruns/underruns locally or to developer
- Allow project to continue and reset baseline

SPP 21

Process Flowchart



SPP 22

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SPP Response to RSC Motions

RSC Motion 2: The Novation Process

Section 3.3(c), SPP Membership Agreement

- A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place
- If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

SPP OATT – Attachment O, Section VI (6)

- A Designated TO may elect to arrange for another entity or another existing TO to build and own all or part of the project in its place subject to:
  - Entities that have obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where project is located
  - Entities that meet the creditworthiness requirements of the Transmission Provider
  - Entities that have signed or are capable and willing to sign the SPP Membership Agreement as a Transmission Owner upon selection of its proposal to construct and own the project, and
  - Entities that meet such other technical, financial and managerial qualifications as are specified in the Transmission Provider’s business practices

Assignment versus Novation

- Assignment: TO can transfer responsibility for a project but remains legally and financially obligated to construct the project
- Novation: TO may seek to transfer all legal and financial responsibility and be relieved of all obligation for a project to an existing TO or an entity capable of becoming a TO in accordance with SPP OATT and Membership Agreement

Novation Process Documents

- To facilitate novations, SPP created a standard agreement that has been filed with and approved by FERC
- SPP, through the stakeholder process, developed a Transmission Owner Selection process document to address the process for determining if an entity meets the qualifications to become a TO

Reasons for Assignment or Novation

- Factors that can result in a decision by a TO to assign or novate a project
  - Funding or financing limitations
  - Increased costs of funding
  - Inability to timely construct the project
- Example of limitations/restrictions of RUS funding

FERC Incentives

- In response to the Energy Policy Act of 2005, FERC Order 679 implementing new policies regarding TOs' cost of service – providing incentives
- Allowed TOs to include 100% of CWIP in rate base
- FERC incentives are available to jurisdictional utilities who seek permission for and provide justification of the need for incentives
- To date within SPP, FERC has approved rates including CWIP only for transcos

Challenges to Side-by-Side Comparison

- Creating a definitive side-by-side comparison of the impacts of ratemaking factors such as NPCC, CWIP, and AFUDC would be challenging for several reasons
  - There is no adequate baseline for a comparison, as it may not be financially feasible for the original designated TO to build the project, at least not at its traditional cost of service. The original designated TO that decides to assign or novate a project may not deem it necessary to estimate project cost
  - The various cost components are interrelated. Neither SPP, the original designated TO, nor a third-party builder is able to precisely determine its financing costs in the project estimation phase
  - The final rate is dependent on a FERC determination regarding the justness and reasonableness of the appropriate incentives
  - The rate impact will depend on the TO which the project is assigned.

Conclusion

The solution to addressing the concerns raised by RSC Motions is multifaceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:

- SPP will provide proposed Novations and analyses to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC
- SPP Staff will increase efforts to communicate with state commissions and commission staff about the regional planning and cost allocation processes, and more specifically how and when estimates for projects are requested by SPP and provided by TOs, including opportunities for adjustments

SPP also suggests increased communication between jurisdictional TOs and state commissions might result in a better understanding of the TOs' processes for development of cost estimates and causes for variations in cost estimates.

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Regional Standards Whitepaper

RSC Motion 3

- **RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200 kV and above that are regionally funded.**

Purpose

- **Provide a consistent and economic construction standard that can be implemented by all transmission owners and builders on the SPP transmission system.**

Benefits of Regional Standard

- **Uniformity throughout SPP footprint**
- **Reduces compatibility issues**
- **Enhance reliability**
- **Create level playing field for all builders**

Design of the Standard

- **SPP staff in collaboration with TWG will develop a draft of the Standard**
- **Initial focus will be tasks that may cause cost overruns**
- **TWG and MOPC will approve the final standard**

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Major Components that may be considered for Design Standards

- Fiber optic ground wire construction standards
- Structure/wooden pole construction specifications
- Foundation construction standards
- Substation control room construction standards
- Insulation and insulation hardware construction specifications
- Conductor size
- Minimum ampacity value

SPP.ORG 7

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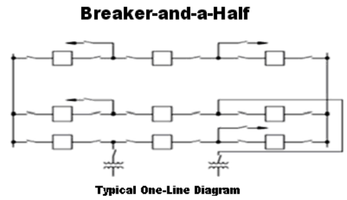
SPP Proposed Substation Bus Arrangement

Voltage	Number of terminals	Substation Arrangement
230 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four	Ring Bus
	Five	Ring Bus
	Six	Ring Bus
	Seven or greater	Breaker and a half
345 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Ring Bus
765 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Breaker and a half

SPP.ORG 8

Proposed Minimum Terminal Equipment Rating

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000



Proposed Conductor Size

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Structure type

- Structure design should be based on National Electrical Safety Code
- The transmission line design engineer should complete an economic study to determine the correct structure type (wood, steel, or prestressed concrete).
- The economic structure type should be selected

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Cost Estimate Improvements

SPP Staff

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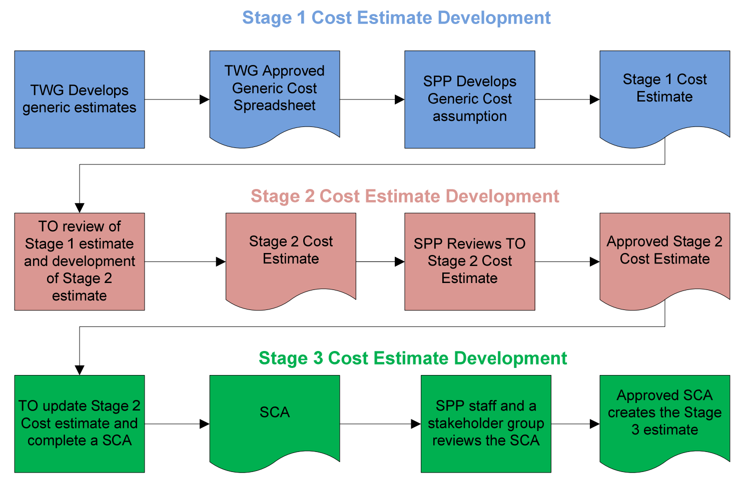
Purpose

- Improve Cost Estimate Process
  - Higher accuracy
  - Standardized Format
  - Increased Detail
  - Greater accountability

Cost Estimate Flow Chart



SPP | 5

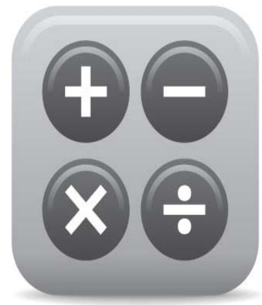
Stage 1: Project Concept Stage

- Estimates developed by SPP
- Estimate tool developed in conjunction with TWG
- Expected to be a high level estimate
- Used for screening large numbers of projects

SPP | 6

Stage 2: Project Analysis Stage

- TO asked to review and update Stage 1 estimate
- TO will provide detailed explanations of changes
- Expected to be within 50% variance from final cost



SPP 7

Stage 3: Review and Approval Stage

- Updated estimate before final report
- Only applies to projects expected to receive an NTC
- Standardized Cost-Estimate Application (SCA)
  - TOs will be required to submit a completed SCA before the project can be approved
- High level of detail estimate
- 25% variance allowed from final construction costs
- SCAs will be reviewed by SPP and working group(s)

SPP 8

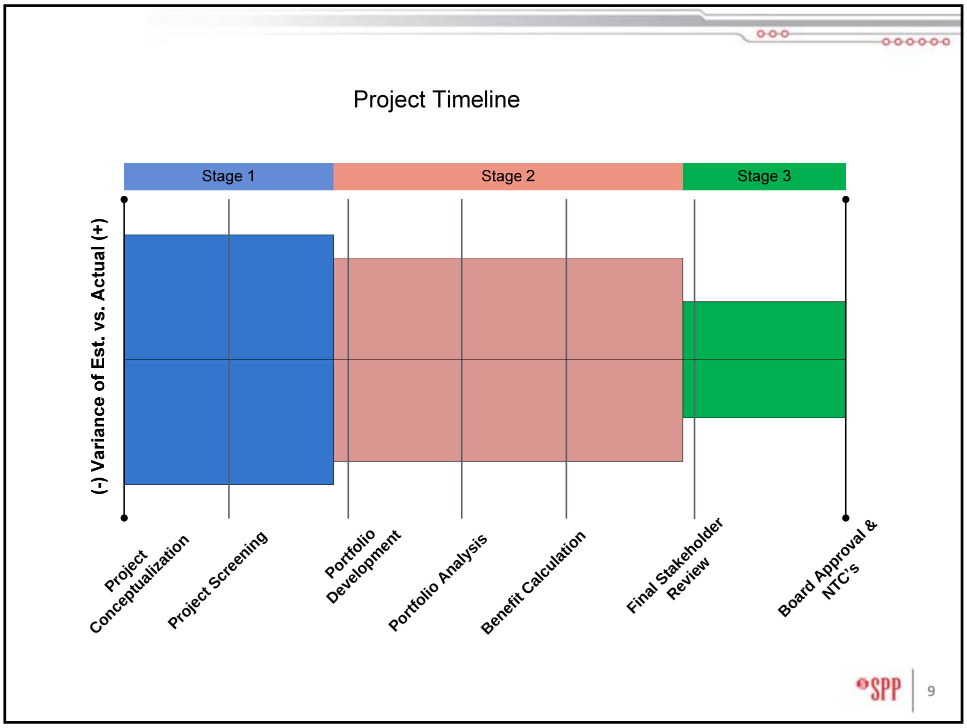

Project Timeline
Stage 1
Stage 2
Stage 3
(-) Variance of Est. vs. Actual (+)
Project Conceptualization
Project Screening
Portfolio Development
Portfolio Analysis
Benefit Calculation
Final Stakeholder Review
Board Approval & NTC's
SPP
9

Exhibit 3

Transmission Owner Proposal for Cost Estimation Review Process

for SPP Regionally Funded Transmission

Presented at Strategic Planning Committee Meeting on December 3, 2010

PROPOSAL FOR COST ESTIMATION REVIEW PROCESS FOR SPP REGIONALLY FUNDED TRANSMISSION

Presented on behalf of
SPP's Transmission Owners

SPP Strategic Planning Committee Meeting
December 3, 2010

REGIONALLY FUNDED TRANSMISSION

- SPP has regionally funded transmission since 2006
- Current Highway / Byway Cost Allocation:
  - Below 100 kV to host zone
  - Greater than 100 kV or less than 300 kV - 1/3 regionally allocated, 2/3 allocated to the host zone
  - Greater than 300 kV – 100 % regionally allocated

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COST CONCERNS

- The RSC and SPP BOD have raised concerns regarding cost estimate increases after a project has been approved by SPP to be included in the regional rate
- Increases in estimates vs. what the actual costs will be

The Purpose of this Presentation
is to propose Cost Estimation concepts
to address those concerns

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PROPOSAL TO ADDRESS COST ESTIMATION & CONTROL CONCERNS

- SPP's Transmission Owners (TOs) offer a proposal for consideration to address the cost concerns raised by the RSC and SPP BOD
- Concepts proposed herein are generally supported by the majority of SPP's TOs
- SPP Staff has participated in the development of these concepts and process

This is a Collaborative Effort

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TO's INVOLVED IN THIS CONCEPT DEVELOPMENT

- AEP
- OG&E
- WESTAR
- XCEL – SPS
- KCP&L
- SUNFLOWER
- WESTERN FARMERS
- NPPD
- EMPIRE DISTRICT
- MIDWEST ENERGY
- LES
- City of Springfield
- OPPD*
- SELECTED SPP STAFF

* Invited but could not participate
*

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PURPOSE

Develop guidelines that provide:

- Greater transparency with respect to the cost of transmission projects that are supported through SPP's Highway rate* (>300 kV),
- Regulators greater certainty with respect to the cost of transmission projects supported through the Highway rate
- Transmission Owners/Constructor's increased certainty that the approved project will be constructed
  - The "Right" Project
  - The "Right" Estimate for SPP analysis
- A streamlined, low cost process for reviewing such projects

*Note projects with a 1/3rd highway portion (less than 300kV or greater than 100kV) could be addressed at a later date

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COST REVIEW PROCESS

The guidelines will provide guidance on:

- What projects are subject to cost review
- What information for cost review the Transmission Owner/Constructor must provide to SPP, using a standard format and the process for SPP's review of a Transmission Owner/Constructor's estimate
- Reasonable timeframe Transmission Owner/Constructor's need to create more accurate cost estimates
- Creation of a process for SPP's review of a project
- Periodic reporting of project estimated costs

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COST REVIEW PROCESS

- Development and implementation of a standardized SPP cost review process for regionally funded projects (>300kV) would:
  - Provide consistent reporting of information regarding transmission projects
  - Increase the level of confidence regarding the accuracy of the cost estimates
  - Recognize that SPP needs accurate information regarding the estimated cost of transmission projects that are issued for a NTC in addition to adequate time for Transmission Owner/Constructor to prepare an estimate
  - Provide standardized guidelines to be used by Transmission Owner/Constructor to provide cost estimates to SPP
  - Provide guidance on when cost estimates need to be updated and for SPP to develop a review process for approving costs that flow through the regional rate

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CURRENT PROCESS AND ADDITIONS

What SPP Does Today

1. Quarterly updates of estimates
   i. Identification of Projects over budget or behind schedule
   ii. Review capability by all (TO, SPP, Board, RSC and publicly available)
2. Cost estimates as directed by the OATT:
   i. Planning grade cost estimate and schedule (Att. O VII. f) page 1360
   ii. Interconnection Facility cost estimates (page 1466)
3. Work with TO on specific potential projects for evaluation by SPP.

In Addition (New)

1. Standard Template for Consistency of Estimates
2. Additional detail for projects ≥ $20 million and more detail for projects ≥ $100 million
3. Bandwidth of error to determine when new review/approvals are needed
4. Detail process outlining the estimating needs for a given project
5. Detail process providing adequate time to develop the appropriate cost estimate in each phase of a project from concept to construction
6. Estimate detail for the appropriate phase from Pre-NTC to Post-NTC

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COST REVIEW THRESHOLDS

– If a cost estimate becomes greater than a pre-defined *bandwidth* of the previous estimate, updated detailed cost estimates and explanations would need to be provided to SPP for its review and consideration (Policy Issue)

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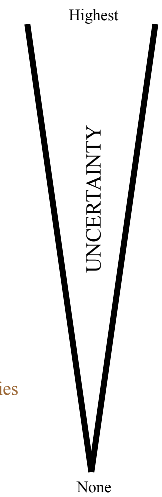
ESTIMATING BEFORE AND AFTER AN NTC

- Conceptual Estimate
  - Based on historical costs
  - Rough straight line path – no detail
- Study Estimate
  - Rough measure of Distance
  - Based on Historical Costs
  - More refined review provided to SPP

NTC Issued

- NTC response (90 days)
- Design Estimate
  - Detailed alternatives
  - Firm Routing
  - Known Environmental Issues
- Construction Estimate
  - All Labor, Material, Equipment, Contingencies
- Actual Cost



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COST REVIEW PROCESS

- A cost review process would provide guidance as to:
  - when a cost estimate should be re-submitted to SPP and define what process SPP would follow to review the updated project costs allowing SPP to determine what action to take, if any, for that project
  - a template that would be completed with detailed information such as:
    - Project details (i.e., H-frame wood pole, monopole steel, monopole concrete, towers, conductor size, ratings, wind and ice loading, etc...)
    - Contingency costs (i.e., Routing risk, environmental risk, land-use risk, commodity unknowns, etc…)
    - Overhead costs (AFUDC, A&G, Regulatory costs, etc…)

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COST REVIEW THRESHOLDS

- In order to conserve SPP's administrative resources, the level of SPP review would vary based on the magnitude of the project:
  - Projects less than 300 kV would not be subject to this review
  - Projects less than $20M would not be subject to this review
  - Projects greater than $20M but less than or equal to $100M would need to provide:
    - An overall project cost estimate and categorized cost breakdown for construction labor, materials, engineering and permitting.
    - An overall cost estimate of each alternative and their cost comparison.
    - Map and one-line diagrams.

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COST REVIEW THRESHOLDS

(cont'd)

- Projects greater than $100M would need to provide:
  - An overall project cost estimate and detailed description of the categorized cost estimates for construction labor, materials, engineering and permitting.
  - An overall project cost estimate of each alternative; SPP may request a detailed description of the categorized cost estimates for construction labor, materials, engineering and permitting of each alternative.
  - Map and one-line diagrams.

- At SPP's request, a stakeholder meeting for all projects greater than $100M may be held

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RECOMMENDATION

- A Task Force should be formed under TWG to develop the detail procedures and process clarification from the concepts outlined in this presentation.
  - The Task Force should be made up of Transmission Construction and Cost Estimation experts from SPP Member companies.
  - Policy issue on conditions when controls exceeded for SPC
- An initial Bandwidth aligned with AACE/EPRI/PMI standards as a starting point.

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KEY TAKE AWAYS

1. Process addresses projects more than $20 million or high voltage projects (more than 300 kV) initially.
2. Improve the cost estimation process by creating:
   1. Templates for consistency among TO's
   2. Guidelines for when reviews are required (Policy)
   3. Bandwidths when estimates need to re-approved
   4. Modified existing Quarterly Review Process
3. Create a Task Force under TWG to develop detail as a Business Process.
   1. SPC deal with policy issues

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RTO Cost-Benefit Analysis

Aquila Missouri Electric Utility Operations

Prepared By:

CRA International

March 28, 2007

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1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

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

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

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

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

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

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

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

1.2. METHODOLOGY

The time horizon for this study is the 10-year period from 2008 through 2017. CRA has performed GE MAPS model runs for this period assuming Aquila Missouri is: 1) Stand-alone, 2) a member of the Midwest ISO, or 3) a member of the SPP RTO. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element in the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was recently used by CRA to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study required by the Energy Policy Act of 2005.

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

1.2.1. Midwest ISO and SPP RTO Modeling

Currently, the Midwest ISO and SPP RTO markets are in different stages of development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights ("FTRs"). In addition, the Midwest ISO has formal plans and budgeting to

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

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

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

The costs and benefits of RTO market development require formal and complex study and evaluation. It is anticipated that the SPP RTO will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study that can be easily performed on behalf of a non-RTO utility such as Aquila Missouri.

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

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

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

1.3. FINDINGS

1.3.1. Net Benefits of Joining an RTO

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2

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

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

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

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

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

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

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

2. ANALYTIC FRAMEWORK

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

2.1. CASES ANALYZED

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

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

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

2.2. COSTS AND BENEFITS

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

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

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

2.3. Midwest ISO and SPP RTO Markets

For purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame used in this study Currently the Midwest ISO and SPP RTO are in different stages of market development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights (FTRs). In addition, the Midwest ISO has formal plans and budgeting to institute an ancillary services market. The Midwest ISO had not yet formalized plans for the formation of a capacity market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member load over the next few years.[14]

The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs per MWh of market member load roughly 20% below that of the Midwest ISO.

The costs and benefits of RTO market development require formal and complex study and consideration. It is anticipated that the SPP will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study easily performed on behalf of a non-RTO utility such as Aquila Missouri. While it is unlikely that SPP would implement the additional market developments instituted by the Midwest ISO by 2008, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design. We will further consider the ramifications of this assumption in subsequent sections.

3. ENERGY MODELING

The energy modeling in this study was performed using General Electric’s MAPS tool. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each

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

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

modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area.

In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. Other than Aquila Missouri, current RTO membership was assumed to continue in all cases. CRA used its current GE MAPS data base to perform the analysis, as well as its current projection of fuel prices and emission allowance prices. In order to assess the impact of future new entry, CRA used its proprietary National Energy & Environmental Model (NEEM) model to develop a capacity expansion forecast. CRA included currently planned or under construction resources throughout the Eastern Interconnect, including Iatan 2 in 2010. Potential CO_2 policies were not considered in this study. A full description of the GE MAPS inputs is contained in Appendix A.

3.1. Modeling Assumptions by Case

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

Table 3
Modeling Assumptions by Case

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

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

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

The default assumption applied for wheeling rates on inter-ties in the modeled Eastern Interconnection region, other than between members of the same RTO, was $2 per MWh for both commitment and dispatch. Based on the Aquila Missouri tariff, the Aquila Missouri wheeling out rate in the Stand-alone case was also set at $2 per MWh for both dispatch and commitment.[15] Based on the Midwest ISO tariff, the wheeling rate from the Midwest ISO to SPP was set at $4 per MWh for dispatch and $6 for commitment.[16] Based on the SPP tariff, the wheeling rate from SPP to the Midwest ISO was set at $2 per MWh for both commitment and dispatch.[17] No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

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

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

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

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

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

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

4. BENEFITS AND COSTS

4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)

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

The major categories of benefits and costs addressed in this study are trade benefits, RTO administrative costs, and Aquila Missouri internal implementation and operating costs. Trade benefits were computed using the GE MAPS results for each case. The methodology used to estimate the impact of each major category of benefits and costs is discussed below along with the corresponding results.

4.2. TRADE BENEFITS

The cases analyzed in this study (Aquila Stand-alone and Aquila in RTO) reflect varying degrees of impediments to trade between Aquila and surrounding regions. In particular, the wheeling rates and flowgate restrictions between Aquila and the Midwest ISO and SPP RTO in the Stand-alone case result in impediments to trade that are reduced when Aquila is a member of an RTO. Reductions in the impediments to trading should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the “trade benefits” referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.[18]

4.2.1. Measurement of Aquila Missouri Trade Benefits

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

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

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

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

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

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

4.2.2. Trade Benefit Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3. ADMINISTRATIVE AND OPERATING COSTS

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

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

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

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

4.3.2. RTO Administrative Charges

Both the Midwest ISO and the SPP RTO incur significant capital and operating costs to operate their markets. These costs are recovered through administrative charges that would be payable by Aquila if it were to be an RTO member. The Midwest ISO assesses these charges under Schedules 10, 16 and 17 under its tariff. The Midwest ISO projects the charges under these schedules over the 2007 to 2011 period to average about 36 cents per MWh of member load.[20] Of this total, about 13 cents per MWh is for Schedule 10 (ISO Cost Recovery Adder), 2.5 cents is for Schedule 16 (FTR Administrative Service), and 20.5 cents is for Schedule 17 (Energy Markets Support). SPP RTO charges are expected to be about 20% lower on a cents per MWh basis over the next few years, including operation of the real-time imbalance market, than those of the Midwest ISO. The SPP RTO costs do not yet

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

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

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

Like the Midwest ISO, the PJM RTO also has day-ahead markets and FTR markets in operation. In 2006, the PJM RTO converted to a system of stated rates that result in projected RTO administrative charges roughly similar to those projected by the Midwest ISO.[21] For purposes of this study, given that the RTO markets are assumed to have similar markets and operations over the long-term study period, the projected Midwest ISO administrative charges were applied in both the Midwest ISO and SPP RTO cases.[22]

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

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

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

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

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

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

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

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

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

4.3.3. FERC Charges

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

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

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

4.3.4. Aquila Internal RTO Market Participation Costs

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

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

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

4.4. Overall Cost-Benefit Results

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

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

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

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

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

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

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

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

4.4.1. High Gas Price Sensitivity

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

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

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

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

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

5. QUALITATIVE CONSIDERATIONS

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

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

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

Costs. Aside from the specific issues identified above, one of the main concerns regarding RTO membership has been the magnitude of the administrative charges, and the perception that individual members may not have enough ability to directly control the underlying RTO expenditures. In response, the Midwest ISO has reduced its budgeted expenditures[25] and is projecting relatively stable costs in terms of costs per MWh over the next five years. Moreover, the PJM RTO has moved to a form of stated rates, rather than a direct formula passthrough of all costs. These stated rate are expected be in place through 2011, indicating greater confidence on the part of RTO management in the predictability of costs as RTO markets mature. In addition, FERC has issued reporting rules to allow for greater

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

transparency in evaluating RTO costs.[26] While these trends appear favorable to the stabilization of RTO costs, there continues to be ongoing uncertainty about future RTO market developments and refinements that result in ongoing cost risk to member utilities.

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

6. CONCLUSION

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

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

7. APPENDIX A: MAPS INPUTS

This appendix summarizes the key inputs to the GE MAPS locational price forecasting model. As formulated for this study, the model's geographic footprint encompasses the U.S. portion of the Eastern Interconnect and the Canadian province of Ontario with the major focus on the SPP, Midwest ISO and surrounding regions. The GE MAPS simulations focus on the ten-year period from 2008 to 2017. The years directly simulated are 2008, 2012 and 2017. Results for intervening years are interpolated.

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

7.1. TRANSMISSION

The CRA model is based on load flow cases provided by the NERC Multiregional Modeling Working Group (MMWG). This analysis uses the modified MMWG 2005 series load flow cases for the summer of 2007 and 2010. The MMWG load flow case encompasses the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. CRA adds to these load flows the Cross-Sound and Neptune high voltage DC cables. Load flow models were further analyzed against regional transmission planning documents and a number of changes were made to the load flow to reflect future transmission projects (those under construction or having a high probability to be implemented, but not included in the original MMWG models).

Monitored constraints originate from the following sources:

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

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

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

7.2. Load Inputs

For each load serving entity, GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. CRA uses the latest EIA-411 load forecast data available (2006) for each company within the study region. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. If study years are to be modeled after the last year for which forecast data is available, CRA uses linear extrapolation to estimate the peak load and annual energy, by company, for the remaining years.

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

7.3. Thermal Unit Characteristics

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

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

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used. Table 9 and Table 10 documents these generic assumptions.[27] As is the case throughout this MAPS analysis, all costs are in real 2005 dollars.

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

Table 9: Characteristics for Generic Thermal Units

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

Table 10: Characteristics for Generic Thermal Units

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

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

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

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

7.4. NUCLEAR UNITS

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

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

7.5. HYDRO UNITS

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

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

7.6. WIND RESOURCES

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

7.7. CAPACITY ADDITIONS AND RETIREMENTS

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

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

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

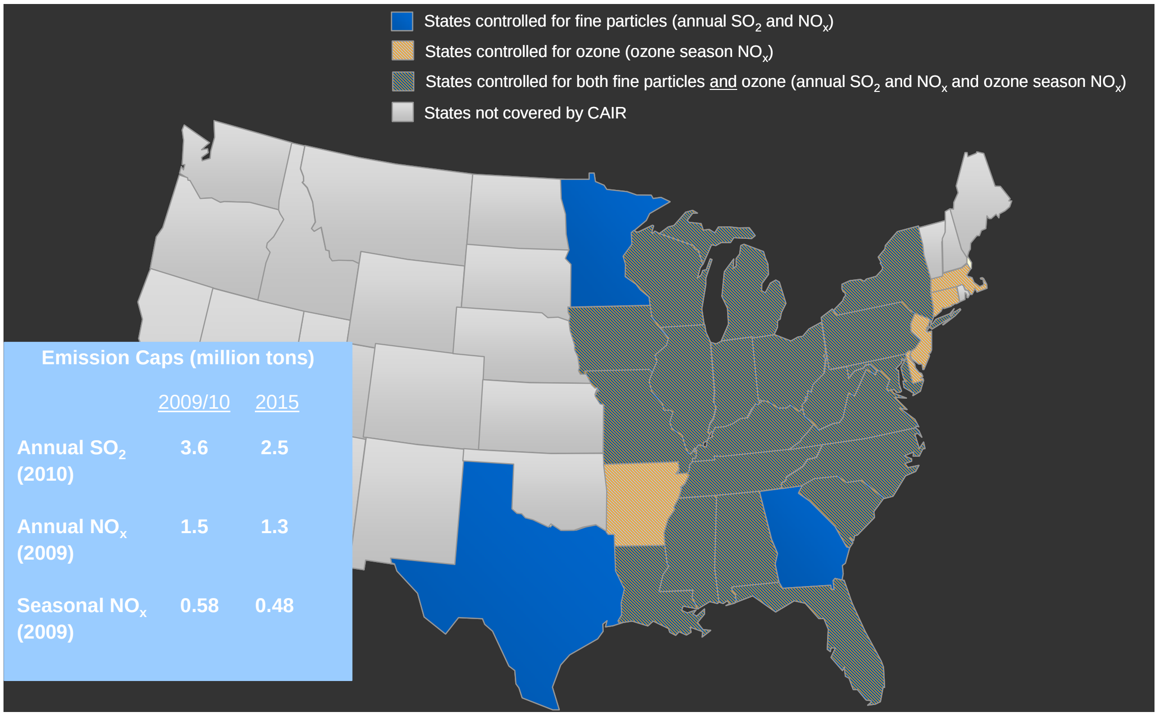
7.8. ENVIRONMENTAL REGULATIONS

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

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

CRA models NO_x and SO_2 emission rates for all units where such data is available. In addition, CRA models compliance with various allowance trading programs, and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the US Environmental Protection Agency. Emission rates for NO_x and SO_2 are obtained from industry futures, in particular those published by the Cantor Environmental Brokerage. CRA used its in-house NEEM model to forecast NO_x and SO_2 permit prices in the long run following the Clean Air Interstate Rules (CAIR) issued by EPA in March 2005. Implications of CAIR rules vary geographically as shown in Figure 1.

Figure 1. Geography of CAIR rules



Source: EPA

The forecast of emission allowance prices for NO_x and SO_2 are presented in Table 11 below. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

Table 11: Forecast Emission Allowance Prices

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

Data Sources. The EPA's Clean Air Markets Emissions Scorecard provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. 2008 emission permit prices are obtained from a Cantor Fitzgerald on-line resource. Allowance price forecasts for 2012 and 2017 are developed by CRA using the NEEM Model.

7.9. EXTERNAL REGION SUPPLY

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

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

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

7.10. DISPATCHABLE DEMAND (INTERRUPTIBLE LOAD)

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

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

7.11. MARKET MODEL ASSUMPTIONS

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

Operating Reserves Requirement (spinning and standby). Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. Table 12 shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

Table 12: Operating Reserve Requirements

ISO/Region	Operating Reserve	Met by Spin
ISO-NE	1,900 MW	67%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
PJM	4,500 MW	67%
Midwest ISO	2,250 MW	65%
MAPP	871 MW	65%
SPP	1,746 MW	65%
MIPU stand alone	85 MW	65%
Entergy	4% of load	65%
Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	1,600 MW	55%

Transmission Losses. Transmission losses are modeled at marginal rates.

7.12. Wheeling Rates

Wheeling rates are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, wheeling rates are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch. For the current analysis, the wheeling rates for commitment were based on the day-ahead firm transmission rates in the individual companies' tariffs, while the rate for dispatch was based on the non-firm hourly rates.

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

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

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

7.13. Fuel Prices

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

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

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

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

Coal prices are drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States. Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

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

7.14. NATURAL GAS AND FUEL OIL PRICE FORECAST

7.14.1. Natural Gas Forecast

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

Base Case Forecast: In the near term (through 2012), the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of the closing of December 6, 2006. For 2013 through 2025, CRA uses the EIA Annual Energy Outlook (AEO2006) Reference Case forecast[28]. CRA Base Case forecast for natural gas prices at Henry Hub is shown in Figure 2.

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

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

Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. In the near term (through 2011), the basis forecast is derived from NYMEX Clearport hub futures settlement as of December 6, 2006. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives summer and winter differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

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

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

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

Figure 2. Henry Hub Prices, History and Forecast (in real 2005 $/MMBtu)

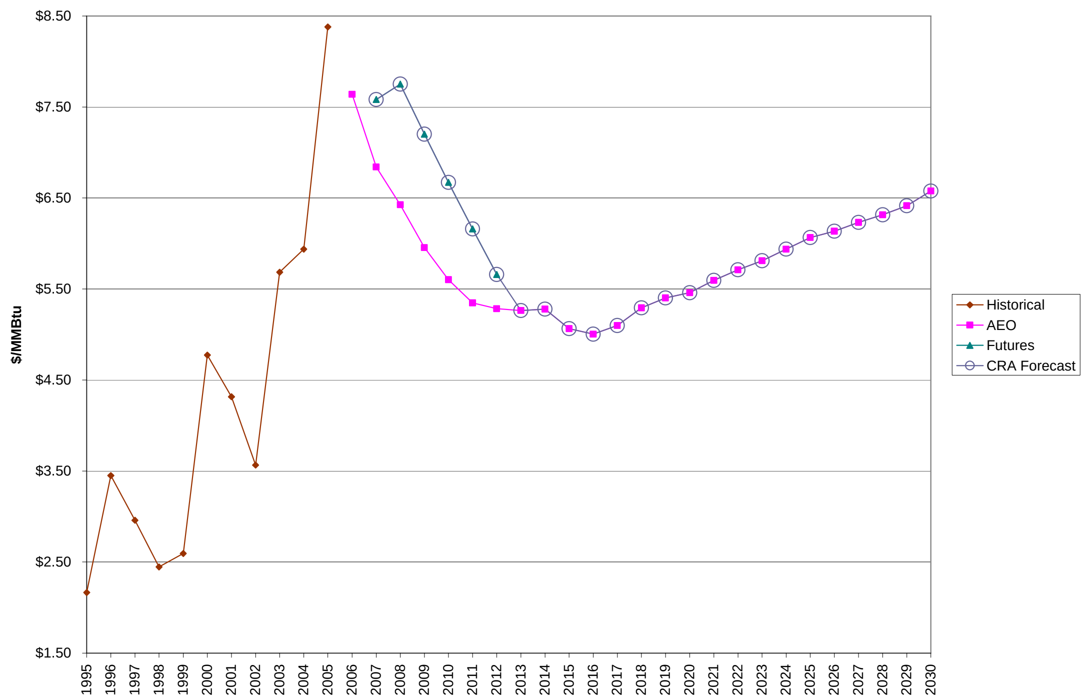
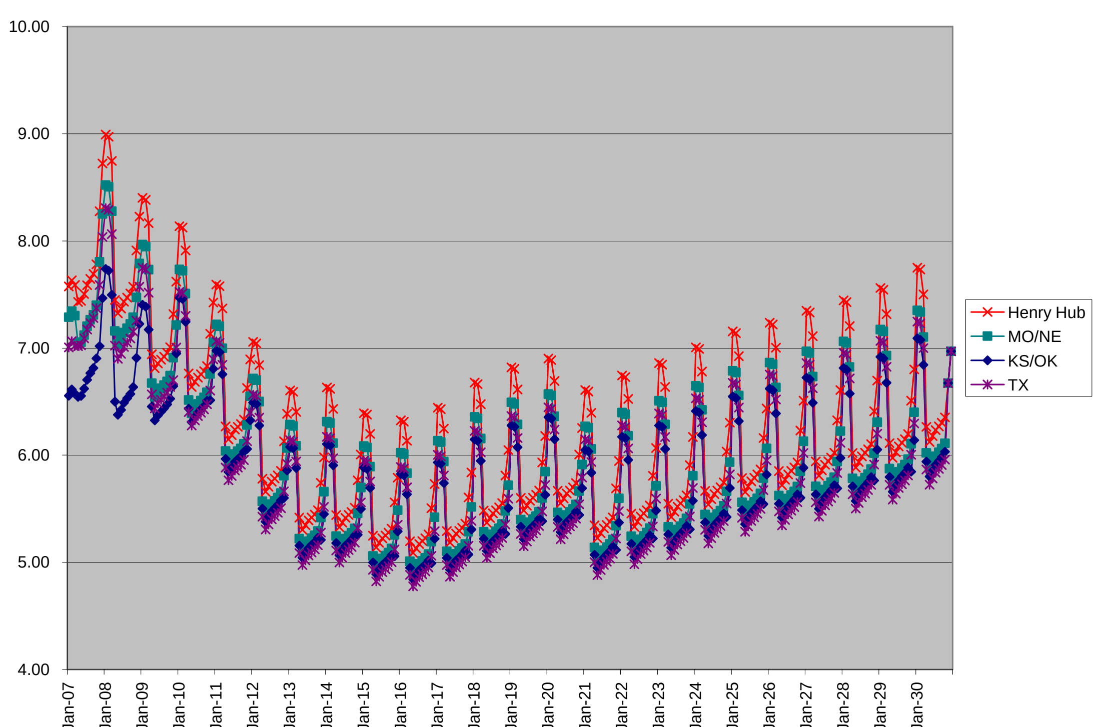


Figure 3. Forecast Regional Natural Gas Prices (Real 2005 $/MMBtu)



7.14.2. Fuel Oil Price Forecast

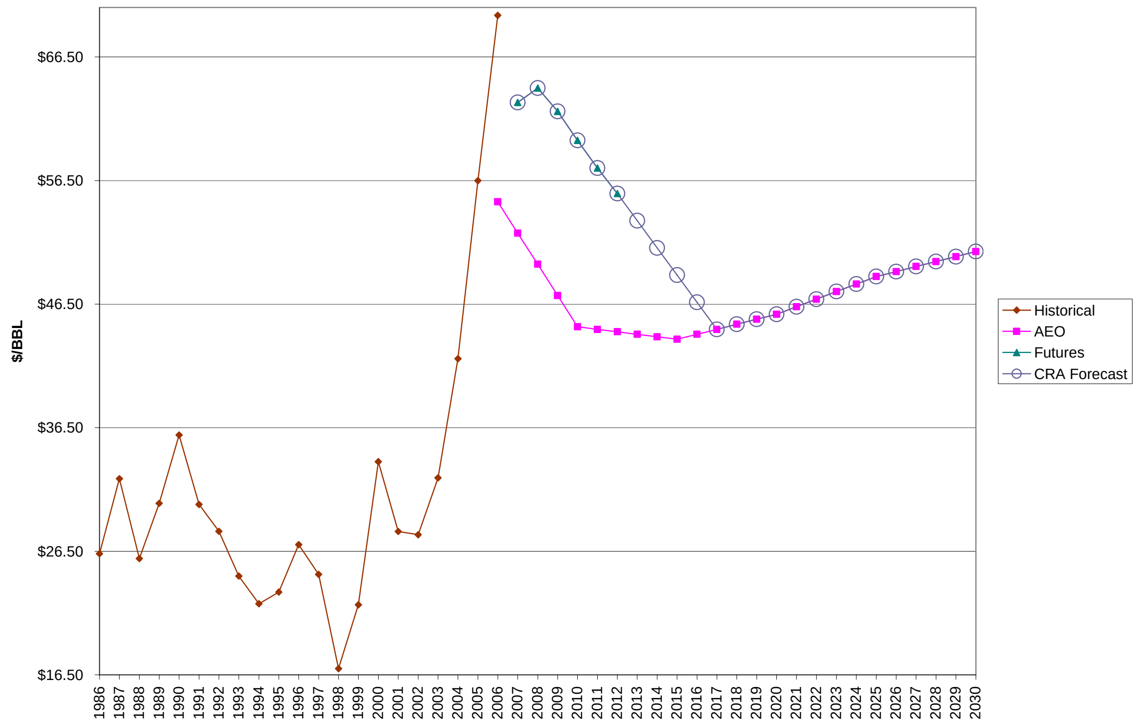
Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is derived from the NYMEX futures prices for light sweet crude oil as of the closing of December 6, 2006. For 2013, 2014 and 2015 the forecast is an interpolation between the futures and the AEO2006. Through 2030, CRA uses the AEO2006 Reference Case forecast. CRA Base Case forecast for light sweet crude oil is presented on Figure 2.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in three steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. New York Harbor prices for the Base Case forecast are shown in Figure 5. Second, New York Harbor prices (both fuel oil #2 and fuel oil #6) are linked to the AEO Reference Case forecast of US average prices of each type of fuel oil used by electric utilities. This derivation is also based on historical regression. Finally, CRA uses AEO forecast to develop yearly regional multipliers linking national average prices and prices by census region. Petroleum Business Tax of $0.45/MMBtu for fuel oil #6 and $0.63/MMBtu for fuel oil #2 is added to oil prices for New York State.

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

Figure 4. Crude Oil Prices: History and Projection (Real 2005 $/BBL)



7.15. Natural Gas Price Sensitivity Assumption

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

8. APPENDIX B: AQUILA MISSOURI RESOURCES

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

Table 14
Aquila Missouri Generating Capacity

(MW, summer rating)

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

9. APPENDIX C: SUPPORTING DETAIL

9.1. ANNUAL RESULTS

9.1.1. Member of Midwest ISO

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

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

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

9.1.2. Member of SPP RTO

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

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

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

9.2. ADMINISTRATIVE AND OPERATING COSTS

9.2.1. Savings from RTO Provision of Transmission Functions

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

Function 1. Reliability Coordination

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

Function 2. Tariff Administration

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

Function 3. OASIS Administration

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

Function 4. ATC/TTC Calculations

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

Function 5. Scheduling Agent

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

Function 6. Regional Transmission Planning

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

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

Table 17
Annual Costs for Aquila Missouri to Provide Transmission/Reliability Functions
(in thousands of dollars)

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

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

9.2.2. RTO Administrative Costs

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

Table 18

Annual RTO Administrative Charges for Aquila Missouri

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

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

9.2.3. Additional FERC Charges

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

Table 19: Additional FERC Annual Charges if in RTO

(in thousands of dollars unless noted)

Historical FERC Charges for Aquila-Missouri

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

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

FERC Charges if in RTO:

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

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

(a) - Midwest ISO, Schedule 10 FERC Rate, forecast 2007 dollars for MISO
(b) - SPP 2006 IE-411, page 24.
(c) GDP Deflator:

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

1w - Oper Reserve Report - Summary - 2 (generated on 07/06/2011 15:17:50 CPT)

:	Parameters
Date Range:	(01/01/2009 - 12/31/2009)
Time Zone:	CPT
Currency Convert To:	USD
MW Sign Convention:	PURCHASE - SALE +
Price Sign Convention:	PURCHASE - SALE +
:	Conditions
Deal Market:	KCPL
Deal Book:	GPES/KCPL SPLY PWR/KCPL SPLY PWR - OPER RES

Counter Party	Transaction Type	Deal Book	Month	Total MW	Price		2009	2010	Through June 2011
AECI	P	KCPL SPLY PWR - OPER RES	April	-124	-5,071.60				
AECI	P	KCPL SPLY PWR - OPER RES	August	-96	-3,851.40				
AECI	P	KCPL SPLY PWR - OPER RES	December	-44	-2,212.20				
AECI	P	KCPL SPLY PWR - OPER RES	February	-25	-1,326.50				
AECI	P	KCPL SPLY PWR - OPER RES	July	-56	-2,292.60				
AECI	P	KCPL SPLY PWR - OPER RES	June	-70	-2,674.00				
AECI	P	KCPL SPLY PWR - OPER RES	March	-16	-530				
AECI	P	KCPL SPLY PWR - OPER RES	May	-47	-1,953.75				
AECI	P	KCPL SPLY PWR - OPER RES	November	-45	-1,740.00				
AECI	P	KCPL SPLY PWR - OPER RES	October	-50	-2,418.00				
AECI	P	KCPL SPLY PWR - OPER RES	September	-26	-956				
		Total For KCPL SPLY PWR - OPER RES		-599	-25,026.05				
AECI	S	KCPL SPLY PWR - OPER RES	April	14	505.6				
AECI	S	KCPL SPLY PWR - OPER RES	December	21	998.9				
AECI	S	KCPL SPLY PWR - OPER RES	February	46	1,621.40				
AECI	S	KCPL SPLY PWR - OPER RES	July	4	120				
AECI	S	KCPL SPLY PWR - OPER RES	March	40	1,515.00				
AECI	S	KCPL SPLY PWR - OPER RES	May	22	968				
AECI	S	KCPL SPLY PWR - OPER RES	October	5	275				
AECI	S	KCPL SPLY PWR - OPER RES	September	29	870				
		Total For KCPL SPLY PWR - OPER RES		181	6,873.90				
Total For AECI				-418	-18,152.15				
AEP	P	KCPL SPLY PWR - OPER RES	April	-251	-13,627.25				
AEP	P	KCPL SPLY PWR - OPER RES	August	-189	-7,625.59				
AEP	P	KCPL SPLY PWR - OPER RES	December	-67	-6,095.07				
AEP	P	KCPL SPLY PWR - OPER RES	February	-42	-1,202.19				
AEP	P	KCPL SPLY PWR - OPER RES	July	-121	-5,812.15				

AEP	P	KCPL SPLY PWR - OPER RES	June	-136	-6,021.86			
AEP	P	KCPL SPLY PWR - OPER RES	March	-25	-634.82			
AEP	P	KCPL SPLY PWR - OPER RES	May	-122	-5,074.20			
AEP	P	KCPL SPLY PWR - OPER RES	November	-77	-2,769.22			
AEP	P	KCPL SPLY PWR - OPER RES	October	-91	-3,726.01			
AEP	P	KCPL SPLY PWR - OPER RES	September	-56	-1,764.74			
		Total For KCPL SPLY PWR - OPER RES		-1,177	-54,353.10	-1,177	-1,146	-487
AEP	S	KCPL SPLY PWR - OPER RES	December	56	2,993.82			-9
AEP	S	KCPL SPLY PWR - OPER RES	February	35	1,572.00			-256
AEP	S	KCPL SPLY PWR - OPER RES	July	18	566.2			
AEP	S	KCPL SPLY PWR - OPER RES	June	26	2,951.80			
AEP	S	KCPL SPLY PWR - OPER RES	May	9	346.5			
AEP	S	KCPL SPLY PWR - OPER RES	November	14	630			
AEP	S	KCPL SPLY PWR - OPER RES	October	10	328			
AEP	S	KCPL SPLY PWR - OPER RES	September	72	2,349.00			
		Total For KCPL SPLY PWR - OPER RES		240	11,737.32			
Total For AEP				-937	-42,615.78			
BPU	P	KCPL SPLY PWR - OPER RES	April	-17	-1,316.46			
BPU	P	KCPL SPLY PWR - OPER RES	August	-17	-1,124.26			
BPU	P	KCPL SPLY PWR - OPER RES	December	-5	-304			
BPU	P	KCPL SPLY PWR - OPER RES	July	-8	-580.8			
BPU	P	KCPL SPLY PWR - OPER RES	June	-7	-403.4			
BPU	P	KCPL SPLY PWR - OPER RES	March	-1	-32.71			
BPU	P	KCPL SPLY PWR - OPER RES	May	-8	-476.4			
BPU	P	KCPL SPLY PWR - OPER RES	November	-7	-571.68			
BPU	P	KCPL SPLY PWR - OPER RES	October	-5	-259.2			
BPU	P	KCPL SPLY PWR - OPER RES	September	-4	-203.7			
		Total For KCPL SPLY PWR - OPER RES		-79	-5,272.61	-79	-57	-44
BPU	S	KCPL SPLY PWR - OPER RES	April	5	150			
BPU	S	KCPL SPLY PWR - OPER RES	August	1	41.25			
BPU	S	KCPL SPLY PWR - OPER RES	December	2	170			
BPU	S	KCPL SPLY PWR - OPER RES	February	21	2,005.30			
BPU	S	KCPL SPLY PWR - OPER RES	July	14	540			
BPU	S	KCPL SPLY PWR - OPER RES	June	10	440			
BPU	S	KCPL SPLY PWR - OPER RES	March	2	60			
BPU	S	KCPL SPLY PWR - OPER RES	May	7	197.82			
		Total For KCPL SPLY PWR - OPER RES		62	3,604.37			
Total For BPU				-17	-1,668.24			
CCG	P	KCPL SPLY PWR - OPER RES	April	-22	-900.53			
CCG	P	KCPL SPLY PWR - OPER RES	August	-21	-904			
CCG	P	KCPL SPLY PWR - OPER RES	December	-9	-369.37			
CCG	P	KCPL SPLY PWR - OPER RES	February	-9	-375			

CCG	P	KCPL SPLY PWR - OPER RES	July	-20	-830.46			
CCG	P	KCPL SPLY PWR - OPER RES	June	-17	-704.45			
CCG	P	KCPL SPLY PWR - OPER RES	March	-6	-176			
CCG	P	KCPL SPLY PWR - OPER RES	May	-9	-369			
CCG	P	KCPL SPLY PWR - OPER RES	November	-3	-127.38			
CCG	P	KCPL SPLY PWR - OPER RES	October	-22	-867.06			
CCG	P	KCPL SPLY PWR - OPER RES	September	-8	-412.84			
		Total For KCPL SPLY PWR - OPER RES		-146	-6,036.09	-146	-158	-45
CCG	S	KCPL SPLY PWR - OPER RES	April	2	68.2			
CCG	S	KCPL SPLY PWR - OPER RES	December	2	127.6			
CCG	S	KCPL SPLY PWR - OPER RES	June	5	286.1			
CCG	S	KCPL SPLY PWR - OPER RES	March	7	350			
CCG	S	KCPL SPLY PWR - OPER RES	May	13	494			
CCG	S	KCPL SPLY PWR - OPER RES	September	2	70			
		Total For KCPL SPLY PWR - OPER RES		31	1,395.90			
Total For CCG				-115	-4,640.19			
CLEC	P	KCPL SPLY PWR - OPER RES	April	-33	-1,630.29			
CLEC	P	KCPL SPLY PWR - OPER RES	August	-23	-1,117.01			
CLEC	P	KCPL SPLY PWR - OPER RES	December	-10	-695.04			
CLEC	P	KCPL SPLY PWR - OPER RES	February	-5	-306.51			
CLEC	P	KCPL SPLY PWR - OPER RES	July	-15	-767.58			
CLEC	P	KCPL SPLY PWR - OPER RES	June	-20	-1,020.45			
CLEC	P	KCPL SPLY PWR - OPER RES	March	-5	-250			
CLEC	P	KCPL SPLY PWR - OPER RES	May	-15	-750.57			
CLEC	P	KCPL SPLY PWR - OPER RES	November	-13	-684.01			
CLEC	P	KCPL SPLY PWR - OPER RES	October	-16	-901.76			
CLEC	P	KCPL SPLY PWR - OPER RES	September	-12	-533.64			
		Total For KCPL SPLY PWR - OPER RES		-167	-8,656.86	-167	-232	-166
CLEC	S	KCPL SPLY PWR - OPER RES	April	10	360			-20
CLEC	S	KCPL SPLY PWR - OPER RES	December	29	2,552.02			
CLEC	S	KCPL SPLY PWR - OPER RES	February	4	158			
CLEC	S	KCPL SPLY PWR - OPER RES	June	10	500			
CLEC	S	KCPL SPLY PWR - OPER RES	May	38	2,115.00			
CLEC	S	KCPL SPLY PWR - OPER RES	November	29	946			
CLEC	S	KCPL SPLY PWR - OPER RES	October	32	1,365.08			
		Total For KCPL SPLY PWR - OPER RES		152	7,996.10			
Total For CLEC				-15	-660.76			
EDE	P	KCPL SPLY PWR - OPER RES	April	-27	-1,135.83			
EDE	P	KCPL SPLY PWR - OPER RES	August	-14	-600.6			
EDE	P	KCPL SPLY PWR - OPER RES	December	-3	-197.7			
EDE	P	KCPL SPLY PWR - OPER RES	February	-3	-125.4			
EDE	P	KCPL SPLY PWR - OPER RES	July	-9	-195.57			

EDE	P	KCPL SPLY PWR - OPER RES	June	-18	-711.97			
EDE	P	KCPL SPLY PWR - OPER RES	March	-4	-171.6			
EDE	P	KCPL SPLY PWR - OPER RES	May	-11	-492.33			
EDE	P	KCPL SPLY PWR - OPER RES	November	-7	-300.3			
EDE	P	KCPL SPLY PWR - OPER RES	October	-11	-471.9			
EDE	P	KCPL SPLY PWR - OPER RES	September	-6	-257.4			
		Total For KCPL SPLY PWR - OPER RES		-113	-4,660.60	-113	-124	-76
EDE	S	KCPL SPLY PWR - OPER RES	April	6	297			
EDE	S	KCPL SPLY PWR - OPER RES	August	12	666.8			
EDE	S	KCPL SPLY PWR - OPER RES	December	6	312			
EDE	S	KCPL SPLY PWR - OPER RES	June	2	72.6			
EDE	S	KCPL SPLY PWR - OPER RES	March	13	835			
EDE	S	KCPL SPLY PWR - OPER RES	October	10	460			
		Total For KCPL SPLY PWR - OPER RES		49	2,643.40			
Total For EDE				-64	-2,017.20			
ESI	P	KCPL SPLY PWR - OPER RES	April	-703	-27,994.99			
ESI	P	KCPL SPLY PWR - OPER RES	August	-491	-29,548.44			
ESI	P	KCPL SPLY PWR - OPER RES	December	-171	-11,074.70			
ESI	P	KCPL SPLY PWR - OPER RES	February	-114	-5,749.63			
ESI	P	KCPL SPLY PWR - OPER RES	July	-322	-29,773.27			
ESI	P	KCPL SPLY PWR - OPER RES	June	-377	-25,473.11			
ESI	P	KCPL SPLY PWR - OPER RES	March	-61	-2,865.34			
ESI	P	KCPL SPLY PWR - OPER RES	May	-291	-13,828.15			
ESI	P	KCPL SPLY PWR - OPER RES	November	-233	-12,251.47			
ESI	P	KCPL SPLY PWR - OPER RES	October	-293	-13,890.95			
ESI	P	KCPL SPLY PWR - OPER RES	September	-164	-7,248.33			
		Total For KCPL SPLY PWR - OPER RES		-3,220	-179,698.38	-3,220	-2,982	-1,650
ESI	S	KCPL SPLY PWR - OPER RES	December	26	1,430.00			
ESI	S	KCPL SPLY PWR - OPER RES	June	21	630			
ESI	S	KCPL SPLY PWR - OPER RES	October	28	1,577.02			
		Total For KCPL SPLY PWR - OPER RES		75	3,637.02			
Total For ESI				-3,145	-176,061.36			
GRDA	P	KCPL SPLY PWR - OPER RES	April	-32	-3,489.62			
GRDA	P	KCPL SPLY PWR - OPER RES	August	-27	-2,700.00			
GRDA	P	KCPL SPLY PWR - OPER RES	December	-9	-900			
GRDA	P	KCPL SPLY PWR - OPER RES	February	-4	-400			
GRDA	P	KCPL SPLY PWR - OPER RES	July	-15	-1,523.07			
GRDA	P	KCPL SPLY PWR - OPER RES	June	-18	-1,800.00			
GRDA	P	KCPL SPLY PWR - OPER RES	March	-3	-300			
GRDA	P	KCPL SPLY PWR - OPER RES	May	-18	-1,800.00			
GRDA	P	KCPL SPLY PWR - OPER RES	November	-15	-1,500.00			
GRDA	P	KCPL SPLY PWR - OPER RES	October	-11	-1,100.00			

GRDA	P	KCPL SPLY PWR - OPER RES	September	-9	-900			
		Total For KCPL SPLY PWR - OPER RES		-161	-16,412.69	-161	-155	-105
GRDA	S	KCPL SPLY PWR - OPER RES	April	4	120			
		Total For KCPL SPLY PWR - OPER RES		4	120			
Total For GRDA				-157	-16,292.69			
INDN	P	KCPL SPLY PWR - OPER RES	April	-3	-156			
INDN	P	KCPL SPLY PWR - OPER RES	August	-8	-440.8			
INDN	P	KCPL SPLY PWR - OPER RES	July	-1	-42.57			
INDN	P	KCPL SPLY PWR - OPER RES	June	-2	-106			
INDN	P	KCPL SPLY PWR - OPER RES	May	-2	-213.2			
INDN	P	KCPL SPLY PWR - OPER RES	September	-2	-66			
		Total For KCPL SPLY PWR - OPER RES		-18	-1,024.57	-18	-23	-4
INDN	S	KCPL SPLY PWR - OPER RES	August	2	104.62			
INDN	S	KCPL SPLY PWR - OPER RES	February	1	45			
INDN	S	KCPL SPLY PWR - OPER RES	June	7	410			
		Total For KCPL SPLY PWR - OPER RES		10	559.62			
Total For INDN				-8	-464.95			
LEPA	P	KCPL SPLY PWR - OPER RES	April	-7	-362.61			
LEPA	P	KCPL SPLY PWR - OPER RES	August	-1	-57.05			
LEPA	P	KCPL SPLY PWR - OPER RES	December	-3	-241.71			
LEPA	P	KCPL SPLY PWR - OPER RES	February	-2	-123.56			
LEPA	P	KCPL SPLY PWR - OPER RES	June	-3	-150.14			
LEPA	P	KCPL SPLY PWR - OPER RES	November	-2	-105.7			
LEPA	P	KCPL SPLY PWR - OPER RES	October	-6	-425.06			
		Total For KCPL SPLY PWR - OPER RES		-24	-1,465.83	-24	-31	-23
LEPA	S	KCPL SPLY PWR - OPER RES	December	2	143			
LEPA	S	KCPL SPLY PWR - OPER RES	February	3	121			
LEPA	S	KCPL SPLY PWR - OPER RES	June	16	1,052.50			
		Total For KCPL SPLY PWR - OPER RES		21	1,316.50			
Total For LEPA				-3	-149.33			
LES	S	KCPL SPLY PWR - OPER RES	April	3	90			
LES	S	KCPL SPLY PWR - OPER RES	August	5	167.5			
LES	S	KCPL SPLY PWR - OPER RES	May	1	50			
LES	S	KCPL SPLY PWR - OPER RES	September	2	92			
		Total For KCPL SPLY PWR - OPER RES		11	399.5			
Total For LES				11	399.5			
LUS	P	KCPL SPLY PWR - OPER RES	April	-5	-258.98			
LUS	P	KCPL SPLY PWR - OPER RES	August	-8	-394.66			
LUS	P	KCPL SPLY PWR - OPER RES	December	-3	-232.35			
LUS	P	KCPL SPLY PWR - OPER RES	February	-4	-243.28			
LUS	P	KCPL SPLY PWR - OPER RES	July	-6	-298.74			
LUS	P	KCPL SPLY PWR - OPER RES	June	-4	-209.11			

LUS	P	KCPL SPLY PWR - OPER RES	May	-1	-59.31			
LUS	P	KCPL SPLY PWR - OPER RES	October	-2	-131.96			
		Total For KCPL SPLY PWR - OPER RES		-33	-1,828.39	-33	-35	-22
LUS	S	KCPL SPLY PWR - OPER RES	August	2	110			
LUS	S	KCPL SPLY PWR - OPER RES	February	28	1,086.00			
LUS	S	KCPL SPLY PWR - OPER RES	June	35	2,043.00			
		Total For KCPL SPLY PWR - OPER RES		65	3,239.00			
Total For LUS				32	1,410.61			
MPS	P	KCPL SPLY PWR - OPER RES	April	-48	-1,831.34			
MPS	P	KCPL SPLY PWR - OPER RES	August	-29	-1,425.55			
MPS	P	KCPL SPLY PWR - OPER RES	December	-8	-367			
MPS	P	KCPL SPLY PWR - OPER RES	February	-7	-269.6			
MPS	P	KCPL SPLY PWR - OPER RES	July	-19	-1,425.00			
MPS	P	KCPL SPLY PWR - OPER RES	June	-28	-1,252.65			
MPS	P	KCPL SPLY PWR - OPER RES	March	-3	-123			
MPS	P	KCPL SPLY PWR - OPER RES	May	-19	-839.24			
MPS	P	KCPL SPLY PWR - OPER RES	October	-18	-551.7			
MPS	P	KCPL SPLY PWR - OPER RES	September	-10	-300			
		Total For KCPL SPLY PWR - OPER RES		-189	-8,385.08	-189	-206	-133
MPS	S	KCPL SPLY PWR - OPER RES	August	9	382.5			
MPS	S	KCPL SPLY PWR - OPER RES	December	9	426.6			
MPS	S	KCPL SPLY PWR - OPER RES	July	9	450.6			
MPS	S	KCPL SPLY PWR - OPER RES	May	8	334.7			
MPS	S	KCPL SPLY PWR - OPER RES	November	8	240			
MPS	S	KCPL SPLY PWR - OPER RES	October	12	360			
MPS	S	KCPL SPLY PWR - OPER RES	September	7	210			
		Total For KCPL SPLY PWR - OPER RES		62	2,404.40			
Total For MPS				-127	-5,980.68			
NPPD	P	KCPL SPLY PWR - OPER RES	April	-85	-4,077.00			
NPPD	P	KCPL SPLY PWR - OPER RES	August	-56	-2,680.00			
NPPD	P	KCPL SPLY PWR - OPER RES	December	-29	-1,615.00			
NPPD	P	KCPL SPLY PWR - OPER RES	July	-33	-2,295.00			
NPPD	P	KCPL SPLY PWR - OPER RES	June	-30	-900			
NPPD	P	KCPL SPLY PWR - OPER RES	May	-34	-1,020.00			
NPPD	P	KCPL SPLY PWR - OPER RES	November	-36	-2,400.00			
NPPD	P	KCPL SPLY PWR - OPER RES	October	-37	-1,450.00			
NPPD	P	KCPL SPLY PWR - OPER RES	September	-20	-600			
		Total For KCPL SPLY PWR - OPER RES		-360	-17,037.00	-360	-365	-233
NPPD	S	KCPL SPLY PWR - OPER RES	April	5	150			
NPPD	S	KCPL SPLY PWR - OPER RES	June	24	1,440.00			
		Total For KCPL SPLY PWR - OPER RES		29	1,590.00			
Total For NPPD				-331	-15,447.00			

NRG	P	KCPL SPLY PWR - OPER RES	April	-73	-3,843.03			
NRG	P	KCPL SPLY PWR - OPER RES	August	-43	-1,833.96			
NRG	P	KCPL SPLY PWR - OPER RES	December	-21	-1,045.00			
NRG	P	KCPL SPLY PWR - OPER RES	February	-13	-552			
NRG	P	KCPL SPLY PWR - OPER RES	July	-34	-1,613.00			
NRG	P	KCPL SPLY PWR - OPER RES	June	-40	-1,714.00			
NRG	P	KCPL SPLY PWR - OPER RES	March	-6	-192			
NRG	P	KCPL SPLY PWR - OPER RES	May	-37	-1,755.48			
NRG	P	KCPL SPLY PWR - OPER RES	November	-25	-857			
NRG	P	KCPL SPLY PWR - OPER RES	October	-28	-1,150.00			
NRG	P	KCPL SPLY PWR - OPER RES	September	-17	-573			
		Total For KCPL SPLY PWR - OPER RES		-337	-15,128.47	-337	-320	-234
NRG	S	KCPL SPLY PWR - OPER RES	August	5	167.75			
NRG	S	KCPL SPLY PWR - OPER RES	May	10	300			
		Total For KCPL SPLY PWR - OPER RES		15	467.75			
Total For NRG				-322	-14,660.72			
OGE	P	KCPL SPLY PWR - OPER RES	April	-183	-9,156.20			
OGE	P	KCPL SPLY PWR - OPER RES	August	-153	-6,998.68			
OGE	P	KCPL SPLY PWR - OPER RES	December	-52	-2,541.77			
OGE	P	KCPL SPLY PWR - OPER RES	February	-31	-929.47			
OGE	P	KCPL SPLY PWR - OPER RES	July	-94	-4,535.74			
OGE	P	KCPL SPLY PWR - OPER RES	June	-112	-4,863.09			
OGE	P	KCPL SPLY PWR - OPER RES	March	-20	-555.84			
OGE	P	KCPL SPLY PWR - OPER RES	May	-78	-2,688.54			
OGE	P	KCPL SPLY PWR - OPER RES	November	-63	-4,091.84			
OGE	P	KCPL SPLY PWR - OPER RES	October	-74	-3,117.29			
OGE	P	KCPL SPLY PWR - OPER RES	September	-41	-1,201.67			
		Total For KCPL SPLY PWR - OPER RES		-901	-40,680.13	-901	-796	-493
OGE	S	KCPL SPLY PWR - OPER RES	April	10	398.9			
OGE	S	KCPL SPLY PWR - OPER RES	August	46	2,318.00			
OGE	S	KCPL SPLY PWR - OPER RES	December	87	3,740.00			
OGE	S	KCPL SPLY PWR - OPER RES	July	2	60			
OGE	S	KCPL SPLY PWR - OPER RES	June	78	3,357.90			
OGE	S	KCPL SPLY PWR - OPER RES	March	72	2,604.05			
OGE	S	KCPL SPLY PWR - OPER RES	November	12	375.9			
OGE	S	KCPL SPLY PWR - OPER RES	October	29	1,108.75			
OGE	S	KCPL SPLY PWR - OPER RES	September	16	527			
		Total For KCPL SPLY PWR - OPER RES		352	14,490.50			
Total For OGE				-549	-26,189.63			
OPPD	P	KCPL SPLY PWR - OPER RES	April	-74	-3,794.24			
OPPD	P	KCPL SPLY PWR - OPER RES	August	-55	-2,159.62			
OPPD	P	KCPL SPLY PWR - OPER RES	December	-22	-957.5			

OPPD	P	KCPL SPLY PWR - OPER RES	July	-27	-1,773.00			
OPPD	P	KCPL SPLY PWR - OPER RES	June	-34	-1,163.77			
OPPD	P	KCPL SPLY PWR - OPER RES	May	-32	-994.28			
OPPD	P	KCPL SPLY PWR - OPER RES	November	-28	-1,595.56			
OPPD	P	KCPL SPLY PWR - OPER RES	October	-31	-1,135.38			
OPPD	P	KCPL SPLY PWR - OPER RES	September	-20	-414.08			
		Total For KCPL SPLY PWR - OPER RES		-323	-13,987.43	-323	-341	-189
OPPD	S	KCPL SPLY PWR - OPER RES	April	55	2,592.00			
OPPD	S	KCPL SPLY PWR - OPER RES	August	11	2,229.00			
OPPD	S	KCPL SPLY PWR - OPER RES	December	27	1,232.07			
OPPD	S	KCPL SPLY PWR - OPER RES	June	7	398.2			
OPPD	S	KCPL SPLY PWR - OPER RES	May	6	369.6			
OPPD	S	KCPL SPLY PWR - OPER RES	September	12	396			
		Total For KCPL SPLY PWR - OPER RES		118	7,216.87			
Total For OPPD				-205	-6,770.56			
SECI	P	KCPL SPLY PWR - OPER RES	April	-25	-1,683.00			
SECI	P	KCPL SPLY PWR - OPER RES	August	-22	-1,448.00			
SECI	P	KCPL SPLY PWR - OPER RES	December	-6	-400			
SECI	P	KCPL SPLY PWR - OPER RES	February	-4	-216			
SECI	P	KCPL SPLY PWR - OPER RES	July	-12	-612			
SECI	P	KCPL SPLY PWR - OPER RES	June	-14	-857			
SECI	P	KCPL SPLY PWR - OPER RES	March	-3	-105			
SECI	P	KCPL SPLY PWR - OPER RES	May	-12	-788			
SECI	P	KCPL SPLY PWR - OPER RES	November	-11	-699			
SECI	P	KCPL SPLY PWR - OPER RES	October	-11	-606			
SECI	P	KCPL SPLY PWR - OPER RES	September	-8	-394			
		Total For KCPL SPLY PWR - OPER RES		-128	-7,808.00	-128	-96	-66
SECI	S	KCPL SPLY PWR - OPER RES	April	32	1,136.30			
SECI	S	KCPL SPLY PWR - OPER RES	August	44	1,980.00			
SECI	S	KCPL SPLY PWR - OPER RES	December	14	731			
SECI	S	KCPL SPLY PWR - OPER RES	July	2	92.4			
SECI	S	KCPL SPLY PWR - OPER RES	June	15	450			
SECI	S	KCPL SPLY PWR - OPER RES	March	4	152			
SECI	S	KCPL SPLY PWR - OPER RES	November	14	1,019.00			
SECI	S	KCPL SPLY PWR - OPER RES	October	10	420			
		Total For KCPL SPLY PWR - OPER RES		135	5,980.70			
Total For SECI				7	-1,827.30			
SMEPA	P	KCPL SPLY PWR - OPER RES	April	-38	-1,842.00			
SMEPA	P	KCPL SPLY PWR - OPER RES	August	-29	-1,387.00			
SMEPA	P	KCPL SPLY PWR - OPER RES	December	-10	-690			
SMEPA	P	KCPL SPLY PWR - OPER RES	February	-7	-345.45			
SMEPA	P	KCPL SPLY PWR - OPER RES	July	-20	-1,130.90			

SMEPA	P	KCPL SPLY PWR - OPER RES	June	-25	-1,379.19			
SMEPA	P	KCPL SPLY PWR - OPER RES	March	-3	-160.5			
SMEPA	P	KCPL SPLY PWR - OPER RES	May	-20	-1,083.20			
SMEPA	P	KCPL SPLY PWR - OPER RES	November	-16	-702.4			
SMEPA	P	KCPL SPLY PWR - OPER RES	October	-21	-1,226.90			
SMEPA	P	KCPL SPLY PWR - OPER RES	September	-10	-474.7			
		Total For KCPL SPLY PWR - OPER RES		-199	-10,422.24	-199	-187	-105
SMEPA	S	KCPL SPLY PWR - OPER RES	December	3	177			
SMEPA	S	KCPL SPLY PWR - OPER RES	June	10	404.4			
SMEPA	S	KCPL SPLY PWR - OPER RES	November	8	384			
SMEPA	S	KCPL SPLY PWR - OPER RES	October	2	61.6			
		Total For KCPL SPLY PWR - OPER RES		23	1,027.00			
Total For SMEPA				-176	-9,395.24			
SPS	P	KCPL SPLY PWR - OPER RES	April	-204	-11,611.10			
SPS	P	KCPL SPLY PWR - OPER RES	August	-134	-6,344.17			
SPS	P	KCPL SPLY PWR - OPER RES	December	-49	-3,076.53			
SPS	P	KCPL SPLY PWR - OPER RES	February	-19	-721.11			
SPS	P	KCPL SPLY PWR - OPER RES	July	-87	-4,249.04			
SPS	P	KCPL SPLY PWR - OPER RES	June	-94	-4,181.75			
SPS	P	KCPL SPLY PWR - OPER RES	March	-19	-698.83			
SPS	P	KCPL SPLY PWR - OPER RES	May	-89	-3,911.42			
SPS	P	KCPL SPLY PWR - OPER RES	November	-70	-2,793.10			
SPS	P	KCPL SPLY PWR - OPER RES	October	-79	-2,778.98			
SPS	P	KCPL SPLY PWR - OPER RES	September	-48	-1,673.85			
		Total For KCPL SPLY PWR - OPER RES		-892	-42,039.88	-892	-698	-461
SPS	S	KCPL SPLY PWR - OPER RES	April	23	930			
SPS	S	KCPL SPLY PWR - OPER RES	August	1	35			
SPS	S	KCPL SPLY PWR - OPER RES	December	3	155.1			
SPS	S	KCPL SPLY PWR - OPER RES	February	13	614.9			
SPS	S	KCPL SPLY PWR - OPER RES	July	11	220			
SPS	S	KCPL SPLY PWR - OPER RES	June	11	330			
SPS	S	KCPL SPLY PWR - OPER RES	May	21	678			
SPS	S	KCPL SPLY PWR - OPER RES	October	2	60			
SPS	S	KCPL SPLY PWR - OPER RES	September	32	990			
		Total For KCPL SPLY PWR - OPER RES		117	4,013.00			
Total For SPS				-775	-38,026.88			
SWPA	P	KCPL SPLY PWR - OPER RES	April	-63	-4,095.00			
SWPA	P	KCPL SPLY PWR - OPER RES	August	-62	-4,030.00			
SWPA	P	KCPL SPLY PWR - OPER RES	December	-21	-1,365.00			
SWPA	P	KCPL SPLY PWR - OPER RES	February	-14	-910			
SWPA	P	KCPL SPLY PWR - OPER RES	July	-31	-2,015.00			
SWPA	P	KCPL SPLY PWR - OPER RES	June	-36	-2,340.00			

SWPA	P	KCPL SPLY PWR - OPER RES	March	-8	-520			
SWPA	P	KCPL SPLY PWR - OPER RES	May	-31	-2,015.00			
SWPA	P	KCPL SPLY PWR - OPER RES	November	-30	-1,950.00			
SWPA	P	KCPL SPLY PWR - OPER RES	October	-19	-1,235.00			
SWPA	P	KCPL SPLY PWR - OPER RES	September	-13	-845			
		Total For KCPL SPLY PWR - OPER RES		-328	-21,320.00	-328	-274	-155
SWPA	S	KCPL SPLY PWR - OPER RES	February	4	120			
SWPA	S	KCPL SPLY PWR - OPER RES	September	3	126			
		Total For KCPL SPLY PWR - OPER RES		7	246			
Total For SWPA				-321	-21,074.00			
WAUE	P	KCPL SPLY PWR - OPER RES	April	-21	-2,100.00			
WAUE	P	KCPL SPLY PWR - OPER RES	August	-15	-990			
WAUE	P	KCPL SPLY PWR - OPER RES	December	-6	-280			
WAUE	P	KCPL SPLY PWR - OPER RES	July	-9	-594			
WAUE	P	KCPL SPLY PWR - OPER RES	June	-10	-660			
WAUE	P	KCPL SPLY PWR - OPER RES	May	-10	-1,000.00			
WAUE	P	KCPL SPLY PWR - OPER RES	November	-9	-405			
WAUE	P	KCPL SPLY PWR - OPER RES	October	-7	-446			
WAUE	P	KCPL SPLY PWR - OPER RES	September	-5	-330			
		Total For KCPL SPLY PWR - OPER RES		-92	-6,805.00	-92	-608	-428
WAUE	S	KCPL SPLY PWR - OPER RES	June	4	120			
		Total For KCPL SPLY PWR - OPER RES		4	120			
Total For WAUE				-88	-6,685.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	April	-138	-10,321.57			
WEI-BU	P	KCPL SPLY PWR - OPER RES	August	-114	-4,440.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	December	-55	-1,963.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	February	-32	-1,420.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	July	-83	-4,680.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	June	-103	-5,038.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	March	-20	-492			
WEI-BU	P	KCPL SPLY PWR - OPER RES	May	-86	-3,497.50			
WEI-BU	P	KCPL SPLY PWR - OPER RES	November	-68	-4,016.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	October	-77	-3,488.00			
WEI-BU	P	KCPL SPLY PWR - OPER RES	September	-45	-1,020.00			
		Total For KCPL SPLY PWR - OPER RES		-821	-40,376.07	-821	-767	-494
WEI-BU	S	KCPL SPLY PWR - OPER RES	April	25	750			
WEI-BU	S	KCPL SPLY PWR - OPER RES	August	14	616			
WEI-BU	S	KCPL SPLY PWR - OPER RES	December	20	1,300.00			
WEI-BU	S	KCPL SPLY PWR - OPER RES	February	17	1,535.32			
WEI-BU	S	KCPL SPLY PWR - OPER RES	March	13	585			
WEI-BU	S	KCPL SPLY PWR - OPER RES	May	6	247			
WEI-BU	S	KCPL SPLY PWR - OPER RES	October	16	517			

		Total For KCPL SPLY PWR - OPER RES		111	5,550.32				
Total For WEI-BU				-710	-34,825.75				
WFEC	P	KCPL SPLY PWR - OPER RES	April	-30	-1,828.80				
WFEC	P	KCPL SPLY PWR - OPER RES	August	-28	-1,422.00				
WFEC	P	KCPL SPLY PWR - OPER RES	December	-12	-880				
WFEC	P	KCPL SPLY PWR - OPER RES	February	-5	-251				
WFEC	P	KCPL SPLY PWR - OPER RES	July	-20	-703				
WFEC	P	KCPL SPLY PWR - OPER RES	June	-19	-860				
WFEC	P	KCPL SPLY PWR - OPER RES	March	-3	-135				
WFEC	P	KCPL SPLY PWR - OPER RES	May	-15	-875				
WFEC	P	KCPL SPLY PWR - OPER RES	November	-13	-572				
WFEC	P	KCPL SPLY PWR - OPER RES	October	-13	-670				
WFEC	P	KCPL SPLY PWR - OPER RES	September	-8	-340				
		Total For KCPL SPLY PWR - OPER RES		-166	-8,536.80		-166	-132	-100
WFEC	S	KCPL SPLY PWR - OPER RES	August	13	428				
WFEC	S	KCPL SPLY PWR - OPER RES	December	19	589.7				
WFEC	S	KCPL SPLY PWR - OPER RES	February	14	751.24				
WFEC	S	KCPL SPLY PWR - OPER RES	July	3	165				
WFEC	S	KCPL SPLY PWR - OPER RES	November	13	535				
		Total For KCPL SPLY PWR - OPER RES		62	2,468.94				
Total For WFEC				-104	-6,067.86				
Grand Total				-8,537	-447,863.16	Total	-9,874	-9,733	-5,998
						Month	12	12	6
Total: 355 records		Average monthly purchased reserve MWhs (Jan 2009 through June 2011)					-823	-811	-1000

Annual transmission expenses for KCPL Reserves range from $39,700 to $44,900
Average annual transmission expense for KCPL Reserves is approximately $42,900

	2014	2015	2016	2017	
	875	875	875	875	(Average MWh from 2009-2011)
SPP non-firm PTP transmission rate for KCPL per Base Plan PtP Rates .xls	3.78	4.28	4.12	4.17	($/MWh)
Average monthly transmission expense	$ 3,308	$ 3,745	$ 3,605	$ 3,649	
Annual transmission expenses for KCPL Reserves	$ 39,690	$ 44,940	$ 43,260	$ 43,785	

1w - Oper Reserve Report - Summary - 2 (generated on 07/06/2011 15:16:23 CPT)

:	Parameters
Date Range:	(01/01/2009 - 12/31/2009)
Time Zone:	CPT
Currency Convert To:	USD
MW Sign Convention:	PURCHASE - SALE +
Price Sign Convention:	PURCHASE - SALE +
:	Conditions
Deal Market:	MPS
Deal Book:	GPES/MPS PWR/MPS PWR - OPER RES

Counter Party	Transaction Type	Deal Book	Month	Total MW	Price	2009	2010	Through June 2011
AECI	P	MPS PWR - OPER RES	April	-12	-521.5			
AECI	P	MPS PWR - OPER RES	August	-19	-708			
AECI	P	MPS PWR - OPER RES	December	-11	-799.95			
AECI	P	MPS PWR - OPER RES	July	-12	-484.5			
AECI	P	MPS PWR - OPER RES	June	-8	-239			
AECI	P	MPS PWR - OPER RES	March	-3	-96			
AECI	P	MPS PWR - OPER RES	May	-16	-666			
AECI	P	MPS PWR - OPER RES	November	-9	-349			
AECI	P	MPS PWR - OPER RES	October	-23	-949.04			
AECI	P	MPS PWR - OPER RES	September	-8	-240			
		Total For MPS PWR - OPER RES		-121	-5052.99			
AECI	S	MPS PWR - OPER RES	April	5	185			
AECI	S	MPS PWR - OPER RES	December	8	470			
AECI	S	MPS PWR - OPER RES	February	20	759.9			
AECI	S	MPS PWR - OPER RES	July	2	60			
AECI	S	MPS PWR - OPER RES	March	18	585			
AECI	S	MPS PWR - OPER RES	May	10	520			
AECI	S	MPS PWR - OPER RES	October	2	88			
AECI	S	MPS PWR - OPER RES	September	10	383			
		Total For MPS PWR - OPER RES		75	3050.9			
Total For AECI				-46	-2002.09			
AEP	P	MPS PWR - OPER RES	April	-25	-2123.2			
AEP	P	MPS PWR - OPER RES	August	-43	-1347.01			
AEP	P	MPS PWR - OPER RES	December	-16	-730.36			
AEP	P	MPS PWR - OPER RES	July	-26	-965.83			
AEP	P	MPS PWR - OPER RES	June	-18	-917.43			
AEP	P	MPS PWR - OPER RES	March	-6	-140.46			
AEP	P	MPS PWR - OPER RES	May	-40	-1719.71			
AEP	P	MPS PWR - OPER RES	November	-17	-574.41			

AEP	P	MPS PWR - OPER RES	October	-39	-1646.82			
AEP	P	MPS PWR - OPER RES	September	-17	-466.42			
		Total For MPS PWR - OPER RES		-247	-10631.65	-247	-442	-123
AEP	S	MPS PWR - OPER RES	December	22	1214.64			-25
AEP	S	MPS PWR - OPER RES	February	16	714			
AEP	S	MPS PWR - OPER RES	July	7	210			
AEP	S	MPS PWR - OPER RES	June	11	467			
AEP	S	MPS PWR - OPER RES	May	4	132			
AEP	S	MPS PWR - OPER RES	November	6	270			
AEP	S	MPS PWR - OPER RES	October	3	103			
AEP	S	MPS PWR - OPER RES	September	30	993			
		Total For MPS PWR - OPER RES		99	4103.64			
Total For AEP				-148	-6528.01			
BPU	P	MPS PWR - OPER RES	April	-4	-469.49			
BPU	P	MPS PWR - OPER RES	August	-2	-148.8			
BPU	P	MPS PWR - OPER RES	March	-2	-67.56			
BPU	P	MPS PWR - OPER RES	May	-3	-223.2			
BPU	P	MPS PWR - OPER RES	November	-1	-51.84			
BPU	P	MPS PWR - OPER RES	October	-1	-51.84			
		Total For MPS PWR - OPER RES		-13	-1012.73	-13	-21	-9
BPU	S	MPS PWR - OPER RES	April	3	90			
BPU	S	MPS PWR - OPER RES	February	8	345.6			
BPU	S	MPS PWR - OPER RES	July	7	269			
BPU	S	MPS PWR - OPER RES	June	3	171			
BPU	S	MPS PWR - OPER RES	May	3	84.78			
		Total For MPS PWR - OPER RES		24	960.38			
Total For BPU				11	-52.35			
CCG	P	MPS PWR - OPER RES	April	-2	-72			
CCG	P	MPS PWR - OPER RES	August	-21	-879			
CCG	P	MPS PWR - OPER RES	December	-4	-188.88			
CCG	P	MPS PWR - OPER RES	July	-4	-144			
CCG	P	MPS PWR - OPER RES	June	-4	-205.44			
CCG	P	MPS PWR - OPER RES	May	-14	-620			
CCG	P	MPS PWR - OPER RES	November	-7	-296.76			
CCG	P	MPS PWR - OPER RES	October	-14	-546.38			
CCG	P	MPS PWR - OPER RES	September	-2	-62			
		Total For MPS PWR - OPER RES		-72	-3014.46	-72	-73	-16
CCG	S	MPS PWR - OPER RES	December	1	63.8			
CCG	S	MPS PWR - OPER RES	June	8	404			
CCG	S	MPS PWR - OPER RES	March	8	398			
CCG	S	MPS PWR - OPER RES	May	6	252			
		Total For MPS PWR - OPER RES		23	1117.8			
Total For CCG (Entergy BA)				-49	-1896.66			

CLEC	P	MPS PWR - OPER RES	April	-1	-50.1			
CLEC	P	MPS PWR - OPER RES	August	-3	-145.54			
CLEC	P	MPS PWR - OPER RES	July	-4	-209.56			
CLEC	P	MPS PWR - OPER RES	June	-1	-53.31			
CLEC	P	MPS PWR - OPER RES	May	-3	-149.38			
CLEC	P	MPS PWR - OPER RES	November	-1	-52.97			
CLEC	P	MPS PWR - OPER RES	October	-7	-368.13			
CLEC	P	MPS PWR - OPER RES	September	-3	-137.34			
		Total For MPS PWR - OPER RES		-23	-1166.33	-23	-88	-28
CLEC	S	MPS PWR - OPER RES	April	5	205.86			-2
CLEC	S	MPS PWR - OPER RES	December	15	1357.64			
CLEC	S	MPS PWR - OPER RES	February	2	70.4			
CLEC	S	MPS PWR - OPER RES	June	4	240			
CLEC	S	MPS PWR - OPER RES	May	16	848.53			
CLEC	S	MPS PWR - OPER RES	November	13	424			
CLEC	S	MPS PWR - OPER RES	October	12	506			
		Total For MPS PWR - OPER RES		67	3652.43			
Total For CLEC				44	2486.1			
DGWD	S	MPS PWR - OPER RES	August	144	6864.48			
DGWD	S	MPS PWR - OPER RES	December	114	8436			
DGWD	S	MPS PWR - OPER RES	July	192	9283.2			
		Total For MPS PWR - OPER RES		450	24583.68			
Total For DGWD				450	24583.68			
EDE	P	MPS PWR - OPER RES	August	-2	-85.8			
EDE	P	MPS PWR - OPER RES	December	-2	-132			
EDE	P	MPS PWR - OPER RES	July	-2	-73.82			
EDE	P	MPS PWR - OPER RES	May	-2	-87			
EDE	P	MPS PWR - OPER RES	November	-2	-85.8			
EDE	P	MPS PWR - OPER RES	October	-4	-171.6			
EDE	P	MPS PWR - OPER RES	September	-1	-40.03			
		Total For MPS PWR - OPER RES		-15	-676.05	-15	-50	-8
EDE	S	MPS PWR - OPER RES	April	2	93.78			
EDE	S	MPS PWR - OPER RES	August	5	314.6			
EDE	S	MPS PWR - OPER RES	December	3	156			
EDE	S	MPS PWR - OPER RES	June	1	55.33			
EDE	S	MPS PWR - OPER RES	March	6	315.3			
EDE	S	MPS PWR - OPER RES	May	2	102.64			
EDE	S	MPS PWR - OPER RES	October	3	127.05			
		Total For MPS PWR - OPER RES		22	1164.7			
Total For EDE				7	488.65			
ESI	P	MPS PWR - OPER RES	April	-69	-2411.36			
ESI	P	MPS PWR - OPER RES	August	-99	-4906.6			
ESI	P	MPS PWR - OPER RES	December	-44	-2766.35			

ESI	P	MPS PWR - OPER RES	July	-62	-3803.19			
ESI	P	MPS PWR - OPER RES	June	-58	-3870.11			
ESI	P	MPS PWR - OPER RES	March	-17	-789.06			
ESI	P	MPS PWR - OPER RES	May	-99	-4974.79			
ESI	P	MPS PWR - OPER RES	November	-47	-2467.09			
ESI	P	MPS PWR - OPER RES	October	-131	-6246.94			
ESI	P	MPS PWR - OPER RES	September	-45	-1662.98			
		Total For MPS PWR - OPER RES		-671	-33898.47	-671	-1,195	-371
ESI	S	MPS PWR - OPER RES	December	13	715			
ESI	S	MPS PWR - OPER RES	June	10	300			
ESI	S	MPS PWR - OPER RES	October	12	910.8			
		Total For MPS PWR - OPER RES		35	1925.8			
Total For ESI				-636	-31972.67			
GRDA	P	MPS PWR - OPER RES	April	-4	-496.54			
GRDA	P	MPS PWR - OPER RES	August	-1	-100			
GRDA	P	MPS PWR - OPER RES	December	-2	-200			
GRDA	P	MPS PWR - OPER RES	July	-5	-500			
GRDA	P	MPS PWR - OPER RES	May	-4	-400			
GRDA	P	MPS PWR - OPER RES	October	-6	-600			
GRDA	P	MPS PWR - OPER RES	September	-3	-300			
		Total For MPS PWR - OPER RES		-25	-2596.54	-25	-56	-15
GRDA	S	MPS PWR - OPER RES	April	2	60			
		Total For MPS PWR - OPER RES		2	60			
Total For GRDA				-23	-2536.54			
INDN	P	MPS PWR - OPER RES	April	-1	-52			
INDN	P	MPS PWR - OPER RES	July	-2	-100.8			
INDN	P	MPS PWR - OPER RES	June	-1	-54.92			
INDN	P	MPS PWR - OPER RES	May	-2	-101.6			
INDN	P	MPS PWR - OPER RES	November	-1	-55.5			
INDN	P	MPS PWR - OPER RES	October	-1	-53			
		Total For MPS PWR - OPER RES		-8	-417.82	-8	-12	0
INDN	S	MPS PWR - OPER RES	August	2	149.6			
INDN	S	MPS PWR - OPER RES	February	1	62			
INDN	S	MPS PWR - OPER RES	June	3	187.33			
		Total For MPS PWR - OPER RES		6	398.93			
Total For INDN				-2	-18.89			
KCPL	P	MPS PWR - OPER RES	August	-9	-382.5			
KCPL	P	MPS PWR - OPER RES	December	-9	-426.6			
KCPL	P	MPS PWR - OPER RES	July	-9	-450.6			
KCPL	P	MPS PWR - OPER RES	May	-8	-334.7			
KCPL	P	MPS PWR - OPER RES	November	-8	-240			
KCPL	P	MPS PWR - OPER RES	October	-12	-360			
KCPL	P	MPS PWR - OPER RES	September	-7	-210			

		Total For MPS PWR - OPER RES		-62	-2404.4	-62	-139	-23
KCPL	S	MPS PWR - OPER RES	April	48	1831.34			
KCPL	S	MPS PWR - OPER RES	August	29	1425.55			
KCPL	S	MPS PWR - OPER RES	December	8	367			
KCPL	S	MPS PWR - OPER RES	February	7	269.6			
KCPL	S	MPS PWR - OPER RES	July	69	2825			
KCPL	S	MPS PWR - OPER RES	June	28	1252.65			
KCPL	S	MPS PWR - OPER RES	March	3	123			
KCPL	S	MPS PWR - OPER RES	May	19	839.24			
KCPL	S	MPS PWR - OPER RES	October	18	551.7			
KCPL	S	MPS PWR - OPER RES	September	10	300			
		Total For MPS PWR - OPER RES		239	9785.08			
Total For KCPL				177	7380.68			
LEPA	P	MPS PWR - OPER RES	August	-3	-162.26			
LEPA	P	MPS PWR - OPER RES	December	-1	-74.97			
LEPA	P	MPS PWR - OPER RES	July	-2	-114.4			
LEPA	P	MPS PWR - OPER RES	June	-2	-101.56			
LEPA	P	MPS PWR - OPER RES	March	-2	-109.7			
LEPA	P	MPS PWR - OPER RES	November	-1	-56.7			
LEPA	P	MPS PWR - OPER RES	October	-2	-123.7			
		Total For MPS PWR - OPER RES		-13	-743.29	-13	-13	-11
LEPA	S	MPS PWR - OPER RES	June	6	366			
		Total For MPS PWR - OPER RES		6	366			
Total For LEPA				-7	-377.29			
LES	S	MPS PWR - OPER RES	April	2	98			
LES	S	MPS PWR - OPER RES	August	1	68			
LES	S	MPS PWR - OPER RES	June	2	110.66			
		Total For MPS PWR - OPER RES		5	276.66			
Total For LES				5	276.66			
LUS	P	MPS PWR - OPER RES	April	-1	-48.34			
LUS	P	MPS PWR - OPER RES	August	-2	-97.1			
LUS	P	MPS PWR - OPER RES	December	-1	-69.64			
LUS	P	MPS PWR - OPER RES	June	-2	-104.52			
LUS	P	MPS PWR - OPER RES	March	-2	-119.62			
LUS	P	MPS PWR - OPER RES	May	-2	-108.78			
LUS	P	MPS PWR - OPER RES	November	-1	-53.26			
LUS	P	MPS PWR - OPER RES	October	-1	-57.29			
		Total For MPS PWR - OPER RES		-12	-658.55	-12	-12	-10
LUS	S	MPS PWR - OPER RES	February	10	330			
LUS	S	MPS PWR - OPER RES	June	17	1080			
		Total For MPS PWR - OPER RES		27	1410			
Total For LUS (Lafayette)				15	751.45			
NPPD	P	MPS PWR - OPER RES	April	-7	-558			

NPPD	P	MPS PWR - OPER RES	August	-11	-430			
NPPD	P	MPS PWR - OPER RES	December	-8	-449			
NPPD	P	MPS PWR - OPER RES	July	-9	-315			
NPPD	P	MPS PWR - OPER RES	June	-6	-180			
NPPD	P	MPS PWR - OPER RES	May	-11	-330			
NPPD	P	MPS PWR - OPER RES	November	-6	-325			
NPPD	P	MPS PWR - OPER RES	October	-15	-636			
NPPD	P	MPS PWR - OPER RES	September	-5	-150			
		Total For MPS PWR - OPER RES		-78	-3373	-78	-132	-54
NPPD	S	MPS PWR - OPER RES	April	2	60			
NPPD	S	MPS PWR - OPER RES	December	2	170			
NPPD	S	MPS PWR - OPER RES	June	11	660			
NPPD	S	MPS PWR - OPER RES	October	2	99			
		Total For MPS PWR - OPER RES		17	989			
Total For NPPD				-61	-2384			
NRG	P	MPS PWR - OPER RES	April	-7	-365.61			
NRG	P	MPS PWR - OPER RES	August	-3	-118			
NRG	P	MPS PWR - OPER RES	December	-6	-330.75			
NRG	P	MPS PWR - OPER RES	July	-7	-330			
NRG	P	MPS PWR - OPER RES	June	-4	-166			
NRG	P	MPS PWR - OPER RES	March	-3	-96			
NRG	P	MPS PWR - OPER RES	May	-13	-661.84			
NRG	P	MPS PWR - OPER RES	November	-4	-143			
NRG	P	MPS PWR - OPER RES	October	-14	-625.9			
NRG	P	MPS PWR - OPER RES	September	-5	-125			
		Total For MPS PWR - OPER RES		-66	-2962.1	-66	-123	-55
NRG	S	MPS PWR - OPER RES	August	2	149.6			
NRG	S	MPS PWR - OPER RES	May	5	260			
		Total For MPS PWR - OPER RES		7	409.6			
Total For NRG (Entergy BA)				-59	-2552.5			
OGE	P	MPS PWR - OPER RES	April	-17	-1591.48			
OGE	P	MPS PWR - OPER RES	August	-31	-1022.22			
OGE	P	MPS PWR - OPER RES	December	-16	-929.02			
OGE	P	MPS PWR - OPER RES	July	-20	-687.64			
OGE	P	MPS PWR - OPER RES	June	-16	-815.6			
OGE	P	MPS PWR - OPER RES	March	-5	-135.71			
OGE	P	MPS PWR - OPER RES	May	-27	-913.72			
OGE	P	MPS PWR - OPER RES	November	-11	-583.42			
OGE	P	MPS PWR - OPER RES	October	-30	-1297.37			
OGE	P	MPS PWR - OPER RES	September	-12	-319.69			
		Total For MPS PWR - OPER RES		-185	-8295.87	-185	-311	-94
OGE	S	MPS PWR - OPER RES	April	2	88			
OGE	S	MPS PWR - OPER RES	August	17	840			

OGE	S	MPS PWR - OPER RES	December	42	3135			
OGE	S	MPS PWR - OPER RES	June	36	1638.63			
OGE	S	MPS PWR - OPER RES	March	25	881			
OGE	S	MPS PWR - OPER RES	November	6	196			
OGE	S	MPS PWR - OPER RES	October	10	404.25			
OGE	S	MPS PWR - OPER RES	September	5	178			
		Total For MPS PWR - OPER RES		143	7360.88			
Total For OGE				-42	-934.99			
OPPD	P	MPS PWR - OPER RES	April	-6	-539.78			
OPPD	P	MPS PWR - OPER RES	August	-11	-257.05			
OPPD	P	MPS PWR - OPER RES	December	-8	-344.32			
OPPD	P	MPS PWR - OPER RES	July	-7	-220			
OPPD	P	MPS PWR - OPER RES	June	-5	-231.8			
OPPD	P	MPS PWR - OPER RES	May	-11	-332.91			
OPPD	P	MPS PWR - OPER RES	November	-6	-268.19			
OPPD	P	MPS PWR - OPER RES	October	-14	-546.58			
OPPD	P	MPS PWR - OPER RES	September	-5	-110			
		Total For MPS PWR - OPER RES		-73	-2850.63	-73	-130	-43
OPPD	S	MPS PWR - OPER RES	April	21	1022			
OPPD	S	MPS PWR - OPER RES	August	5	285			
OPPD	S	MPS PWR - OPER RES	December	13	647.2			
OPPD	S	MPS PWR - OPER RES	June	3	165			
OPPD	S	MPS PWR - OPER RES	May	3	184.8			
OPPD	S	MPS PWR - OPER RES	September	5	168			
		Total For MPS PWR - OPER RES		50	2472			
Total For OPPD				-23	-378.63			
SECI	P	MPS PWR - OPER RES	April	-3	-366			
SECI	P	MPS PWR - OPER RES	August	-5	-292			
SECI	P	MPS PWR - OPER RES	December	-1	-77			
SECI	P	MPS PWR - OPER RES	July	-2	-130			
SECI	P	MPS PWR - OPER RES	June	-3	-198			
SECI	P	MPS PWR - OPER RES	May	-2	-140			
SECI	P	MPS PWR - OPER RES	November	-1	-67			
SECI	P	MPS PWR - OPER RES	October	-4	-245			
SECI	P	MPS PWR - OPER RES	September	-3	-171			
		Total For MPS PWR - OPER RES		-24	-1686	-24	-35	-17
SECI	S	MPS PWR - OPER RES	April	14	460.9			
SECI	S	MPS PWR - OPER RES	August	14	959			
SECI	S	MPS PWR - OPER RES	December	6	339.6			
SECI	S	MPS PWR - OPER RES	July	2	149.6			
SECI	S	MPS PWR - OPER RES	June	7	210			
SECI	S	MPS PWR - OPER RES	March	2	76			
SECI	S	MPS PWR - OPER RES	November	6	453			

SECI	S	MPS PWR - OPER RES	October	3	270.03			
		Total For MPS PWR - OPER RES		54	2918.13			
Total For SECI				30	1232.13			
SMEPA	P	MPS PWR - OPER RES	April	-4	-211.3			
SMEPA	P	MPS PWR - OPER RES	August	-5	-251.2			
SMEPA	P	MPS PWR - OPER RES	December	-3	-220.6			
SMEPA	P	MPS PWR - OPER RES	July	-3	-135.6			
SMEPA	P	MPS PWR - OPER RES	June	-3	-152.33			
SMEPA	P	MPS PWR - OPER RES	March	-2	-107			
SMEPA	P	MPS PWR - OPER RES	May	-5	-272.2			
SMEPA	P	MPS PWR - OPER RES	October	-8	-442.9			
SMEPA	P	MPS PWR - OPER RES	September	-4	-174			
		Total For MPS PWR - OPER RES		-37	-1967.13	-37	-73	-16
SMEPA	S	MPS PWR - OPER RES	June	2	75.35			
SMEPA	S	MPS PWR - OPER RES	November	3	144			
		Total For MPS PWR - OPER RES		5	219.35			
Total For SMEPA				-32	-1747.78			
SPS	P	MPS PWR - OPER RES	April	-20	-1889.62			
SPS	P	MPS PWR - OPER RES	August	-29	-988.64			
SPS	P	MPS PWR - OPER RES	December	-16	-1125.94			
SPS	P	MPS PWR - OPER RES	July	-17	-661.3			
SPS	P	MPS PWR - OPER RES	June	-15	-737.93			
SPS	P	MPS PWR - OPER RES	March	-5	-187.41			
SPS	P	MPS PWR - OPER RES	May	-28	-1272.58			
SPS	P	MPS PWR - OPER RES	November	-14	-572.97			
SPS	P	MPS PWR - OPER RES	October	-36	-2392.08			
SPS	P	MPS PWR - OPER RES	September	-13	-346.74			
		Total For MPS PWR - OPER RES		-193	-10175.21	-193	-261	-92
SPS	S	MPS PWR - OPER RES	April	10	414			
SPS	S	MPS PWR - OPER RES	August	1	35			
SPS	S	MPS PWR - OPER RES	December	2	144.26			
SPS	S	MPS PWR - OPER RES	February	6	283.8			
SPS	S	MPS PWR - OPER RES	July	6	120			
SPS	S	MPS PWR - OPER RES	June	5	255			
SPS	S	MPS PWR - OPER RES	May	11	354			
SPS	S	MPS PWR - OPER RES	September	14	484.5			
		Total For MPS PWR - OPER RES		55	2090.56			
Total For SPS				-138	-8084.65			
SWPA	P	MPS PWR - OPER RES	April	-10	-650			
SWPA	P	MPS PWR - OPER RES	August	-14	-910			
SWPA	P	MPS PWR - OPER RES	December	-5	-325			
SWPA	P	MPS PWR - OPER RES	July	-8	-520			
SWPA	P	MPS PWR - OPER RES	June	-6	-390			

SWPA	P	MPS PWR - OPER RES	March	-3	-195			
SWPA	P	MPS PWR - OPER RES	May	-11	-715			
SWPA	P	MPS PWR - OPER RES	November	-2	-130			
SWPA	P	MPS PWR - OPER RES	October	-9	-585			
SWPA	P	MPS PWR - OPER RES	September	-4	-260			
		Total For MPS PWR - OPER RES		-72	-4680	-72	-121	-31
SWPA	S	MPS PWR - OPER RES	February	1	30			
SWPA	S	MPS PWR - OPER RES	September	2	84			
		Total For MPS PWR - OPER RES		3	114			
Total For SWPA				-69	-4566			
WAUE	P	MPS PWR - OPER RES	August	-6	-396			
WAUE	P	MPS PWR - OPER RES	December	-2	-101			
WAUE	P	MPS PWR - OPER RES	July	-2	-132			
WAUE	P	MPS PWR - OPER RES	June	-1	-66			
WAUE	P	MPS PWR - OPER RES	May	-3	-300			
WAUE	P	MPS PWR - OPER RES	October	-4	-178.65			
WAUE	P	MPS PWR - OPER RES	September	-3	-198			
		Total For MPS PWR - OPER RES		-21	-1371.65	-21	-220	-96
WAUE	S	MPS PWR - OPER RES	June	2	60			
		Total For MPS PWR - OPER RES		2	60			
Total For WAUE				-19	-1311.65			
WEI-BU	P	MPS PWR - OPER RES	April	-17	-1562.05			
WEI-BU	P	MPS PWR - OPER RES	August	-29	-917			
WEI-BU	P	MPS PWR - OPER RES	December	-13	-739			
WEI-BU	P	MPS PWR - OPER RES	July	-20	-849			
WEI-BU	P	MPS PWR - OPER RES	June	-15	-803			
WEI-BU	P	MPS PWR - OPER RES	March	-5	-110			
WEI-BU	P	MPS PWR - OPER RES	May	-29	-1370			
WEI-BU	P	MPS PWR - OPER RES	November	-15	-657			
WEI-BU	P	MPS PWR - OPER RES	October	-31	-1319.8			
WEI-BU	P	MPS PWR - OPER RES	September	-13	-286			
		Total For MPS PWR - OPER RES		-187	-8612.85	-187	-323	-96
WEI-BU	S	MPS PWR - OPER RES	April	15	510			
WEI-BU	S	MPS PWR - OPER RES	August	7	350			
WEI-BU	S	MPS PWR - OPER RES	December	14	880			
WEI-BU	S	MPS PWR - OPER RES	February	7	260.2			
WEI-BU	S	MPS PWR - OPER RES	March	5	225			
WEI-BU	S	MPS PWR - OPER RES	May	3	127			
WEI-BU	S	MPS PWR - OPER RES	October	7	240			
		Total For MPS PWR - OPER RES		58	2592.2			
Total For WEI-BU				-129	-6020.65			
WFEC	P	MPS PWR - OPER RES	April	-2	-102			
WFEC	P	MPS PWR - OPER RES	August	-7	-358			

WFEC	P	MPS PWR - OPER RES	December	-2	-153				
WFEC	P	MPS PWR - OPER RES	July	-3	-150				
WFEC	P	MPS PWR - OPER RES	June	-1	-39				
WFEC	P	MPS PWR - OPER RES	May	-4	-190				
WFEC	P	MPS PWR - OPER RES	November	-1	-44				
WFEC	P	MPS PWR - OPER RES	October	-5	-275				
WFEC	P	MPS PWR - OPER RES	September	-3	-123				
		Total For MPS PWR - OPER RES		-28	-1434		-28	-55	-11
WFEC	S	MPS PWR - OPER RES	August	4	121				
WFEC	S	MPS PWR - OPER RES	December	10	558.2				
WFEC	S	MPS PWR - OPER RES	February	7	329.7				
WFEC	S	MPS PWR - OPER RES	November	6	288				
		Total For MPS PWR - OPER RES		27	1,296.90				
Total For WFEC				-1	-137.1				
Grand Total				-745	-36,303.10	Total	-2125	-3885	-1246
						Months	12	12	6
Total: 314 records		Average monthly purchased reserve MWhs (Jan 2009 through June 2011)					-177	-324	-208

Annual transmission expenses for GMOC Reserves range from $16,500 to $17,700
Average annual transmission expense for GMOC Reserves is approximately $17,000

	2014	2015	2016	2017	
	235	235	235	235	(Average MWh from 2009-2011)
SPP non-firm PTP transmission rate for GMOC per Base Plan PtP Rates .xls	5.85	6.28	6.03	6.02	($/MWh)
Average monthly transmission expense	$ 1,375	$ 1,476	$ 1,417	$ 1,415	
Annual transmission expenses for GMOC Reserves	$ 16,497	$ 17,710	$ 17,005	$ 16,976	

Attachment G

Annual Transmission Revenue Requirement Allocations Projected for Base Plan, Balanced Portfolio, Priority Projects, and ITP

	KCP&L	GMO(1)	Check Totals
2011	$ 10,777,741	$ 6,433,934	$ 17,211,675
2012	$ 17,591,847	$ 8,961,064	$ 26,552,911
2013	$ 21,987,129	$ 10,198,069	$ 32,185,198
2014	$ 42,326,335	$ 19,755,494	$ 62,081,829
2015	$ 37,272,889	$ 15,920,198	$ 53,193,087
2016	$ 36,940,031	$ 14,561,956	$ 51,501,987
2017	$ 46,098,858	$ 19,435,879	$ 65,534,737

Source: Dan Jones with SPP Staff provided the projections, 8/17/11. The numbers include the projected Balanced Portfolio revenue requirement transfers and reflect CWIP recovery where approved by FERC. It assumed the projects are placed in service on January 1 with no rate lag.

Adjusted ATRR Allocation Projections to Reflect Project Schedules and Regulatory Lag

	KCP&L	GMO(1)
2012	$ 12,481,268	$ 7,065,717
2013	$ 18,690,668	$ 9,270,315
2014	$ 27,071,931	$ 12,587,425
2015	$ 41,062,974	$ 18,796,670
2016	$ 37,189,675	$ 15,580,638
2017	$ 39,229,738	$ 15,780,437

Note: The adjusted numbers are weighted averages of the prior and current year values provided by SPP. This is to correct for the assumptions of a January 1 in-service date with no rate lag.

ATRR Lag Weighting Factors

Previous Year	0.75	0.75
Current Year	0.25	0.25

	KCP&L	**GMO**	
Schedule 7	$10,176/MW-yr	$19,248/MW-yr	Assume current tariff rates apply to 2014-2017 (Attachments Q and R)
Schedule 8	$2.45/MWh	$4.63/MWh	On-peak rate
Schedule 1	$.029/MWh	$.015/MWh	Assume current tariff rates apply to 2014-2017 (Attachments Q and R)
Schedule 2	$.001/MWh	$.005/MWh	Assume current tariff rates apply to 2014-2017 (Attachments Q and R)
Schedule 1A	$.283/MWh	$.283/MWh	Assume 2014 rate provided by Scott Smith (SPP) 8/24/11

Projected Point-to-Point Rates Under Schedule 11
$ per MW-Year

	KCP&L	GMO
2012	4,232.30	4,668.64
2013	6,233.29	6,025.90
2014	8,880.39	8,033.99
2015	13,267.79	11,780.17
2016	11,888.46	9,609.98
2017	12,364.60	9,564.43

	Firm Yearly PTP/MW		Non-Firm Hourly PTP/MW	
	KCP&L	GMO	KCP&L	GMO
2012	17,150.18	26,570.92	3.25	5.47
2013	19,151.17	27,928.18	3.47	5.62
2014	21,798.27	29,936.27	3.78	5.85
2015	26,185.67	33,682.45	4.28	6.28
2016	24,806.34	31,512.26	4.12	6.03
2017	25,282.48	31,466.71	4.17	6.02

$ per MW-Hour

2012	0.48	0.53		
2013	0.71	0.69		
2014	1.01	0.92	2.13	1.93
2015	1.51	1.34	3.19	2.83
2016	1.36	1.10	2.86	2.31
2017	1.41	1.09	2.97	2.30
	KCPL - Off Peak	GMO - Off Peak	KCPL - On Peak	GMO - On Peak
	1.32	1.11	2.79	2.34
	0.137	0.137	0.289	0.289
	0.118	0.064	0.249	0.134
	0.255	0.201	0.538	0.423

AEP - KCPL

ZONAL FIRM($)				
Daily	Weekly	Monthly	Annual	Last Updated
39.2	196	848	10176	07/01/2011

ZONAL NON-FIRM($)					
Hourly Off-Peak	Hourly On-Peak	Daily	Weekly	Monthly	Last Updated
1.16	2.45	39.2	196	848	07/01/2011

Schedule Fee($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.029	0.696	4.89	21.2	06/01/2011

Reactive Voltage($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.001	0.012	0.059	0.255	07/01/2011

Base Plan Regional Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.0000	0.0000	5.0800	3.6280	25.398	110.05	1320.6	07/01/2011

Prices based on 1 MW

Base Plan Regional Non Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.3180	0.1510	5.0800	3.6180	25.398	110.05	0.0000	07/01/2011

Base Plan Zonal Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.0000	0.0000	3.7600	2.6850	18.797	81.455	977.46	07/01/2011

Base Plan Zonal Non Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.2350	0.1120	3.7600	2.6780	18.797	81.455	0.0000	07/01/2011

Administration Fee		
Hourly	Daily	Weekly
0.21	5.04	35.28

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Attachment I

AEP - MPS

ZONAL FIRM($)				
Daily	Weekly	Monthly	Annual	Last Updated
74	370	1604	19248	07/01/2011

ZONAL NON-FIRM($)					
Hourly Off-Peak	Hourly On-Peak	Daily	Weekly	Monthly	Last Updated
2.2	4.63	74	370	1604	07/01/2011

Schedule Fee($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.015	0.353	2.48	10.7	06/01/2011

Reactive Voltage($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.005	0.08	0.401	1.735	07/01/2011

Base Plan Regional Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.0000	0.0000	5.0800	3.6280	25.398	110.05	1320.6	07/01/2011

Prices based on 1 MW

Base Plan Regional Non Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.3180	0.1510	5.0800	3.6180	25.398	110.05	0.0000	07/01/2011

Base Plan Zonal Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.0000	0.0000	2.0240	1.4460	10.122	43.862	526.33	07/01/2011

Base Plan Zonal Non Firm							
Hourly On-Peak	Hourly Off-Peak	Daily On-Peak	Daily Off-Peak	Weekly	Monthly	Yearly	Effective Date
0.1270	0.0600	2.0240	1.4420	10.122	43.862	0.0000	07/01/2011

Administration Fee		
Hourly	Daily	Weekly
0.21	5.04	35.28

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Southwest Power Pool

Cost-Benefit Analysis

Performed for the SPP Regional State Committee

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

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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.

[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]

---

[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.

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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)

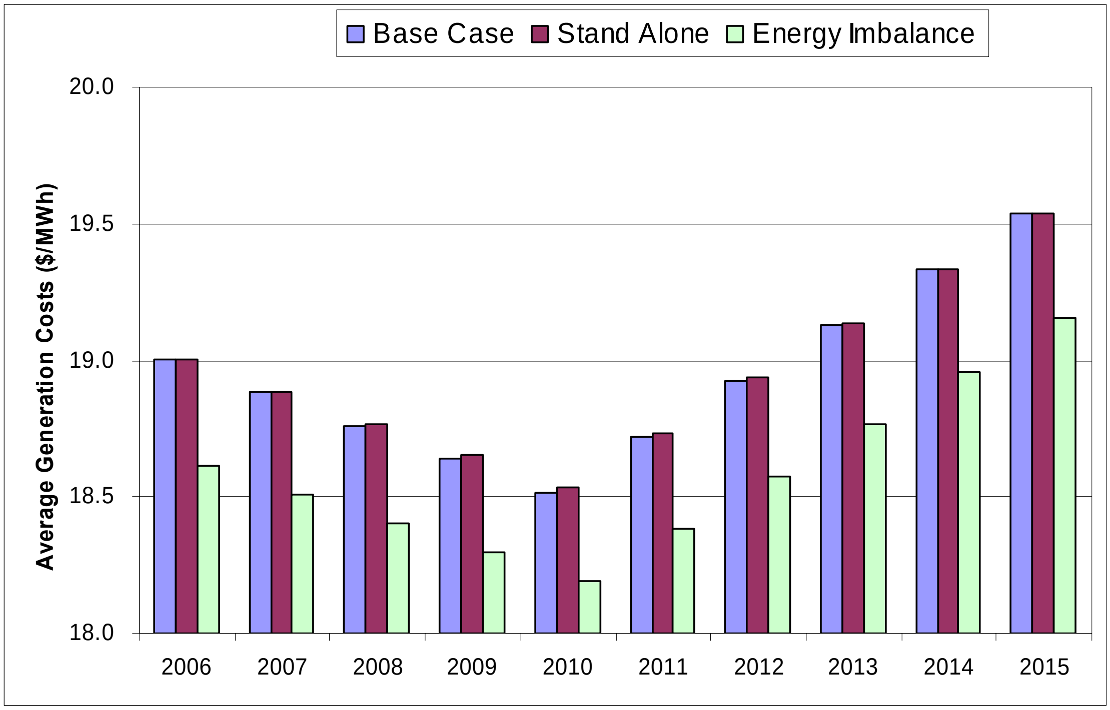
	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

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

[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.

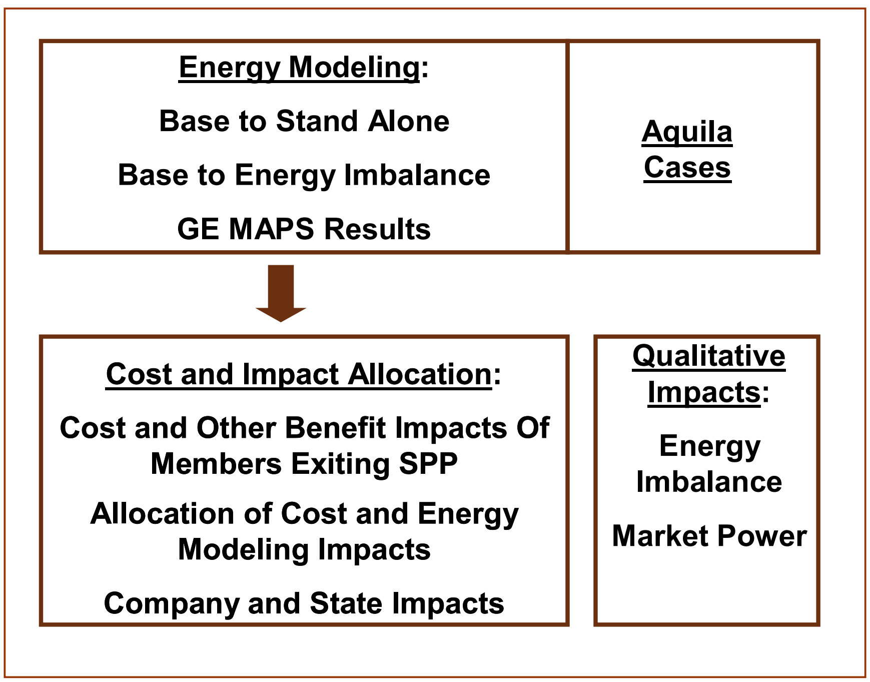
CRA presented status updates and detailed approaches throughout the study period. CRA and the CBTF members reviewed the results and refined the assumptions. This report presents the results of the modeling analyses and of the qualitative Cost-Benefit elements.

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

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[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.

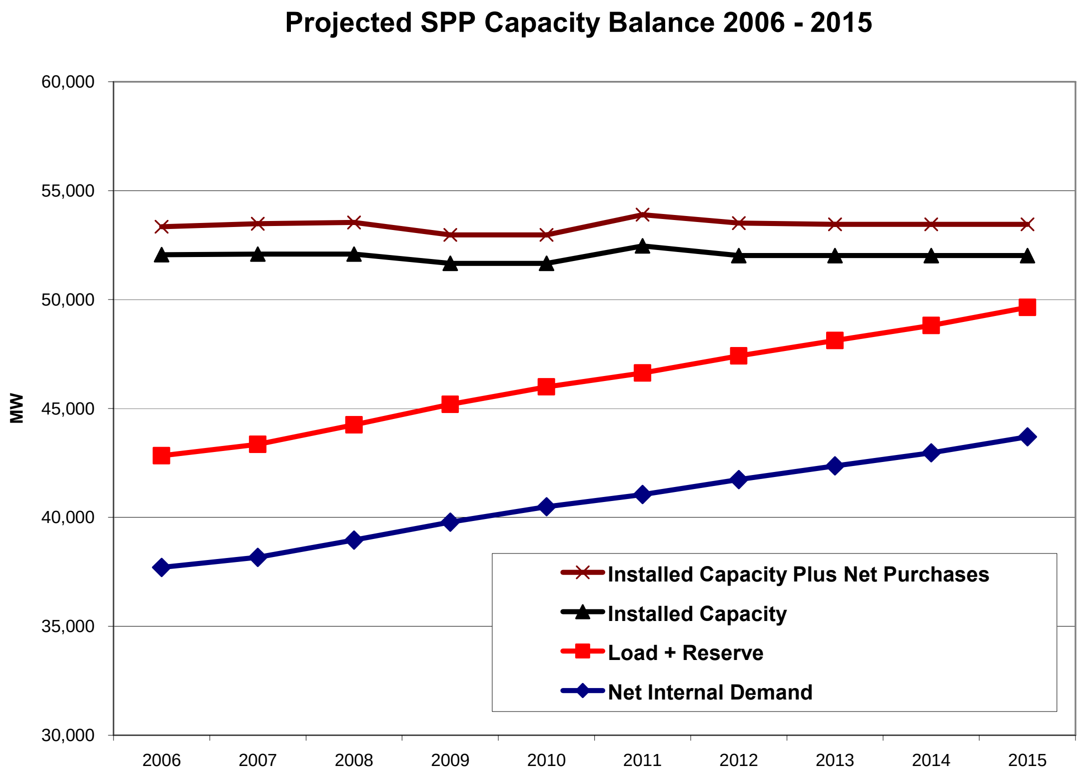
Note also that in each of modeling scenarios it is assumed that the entire volume of the market is cleared through the simulation's spot market. To the extent that transmission owners' self-dispatch and self-deployment is efficient and to the extent that the bilateral market is efficient, the results 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

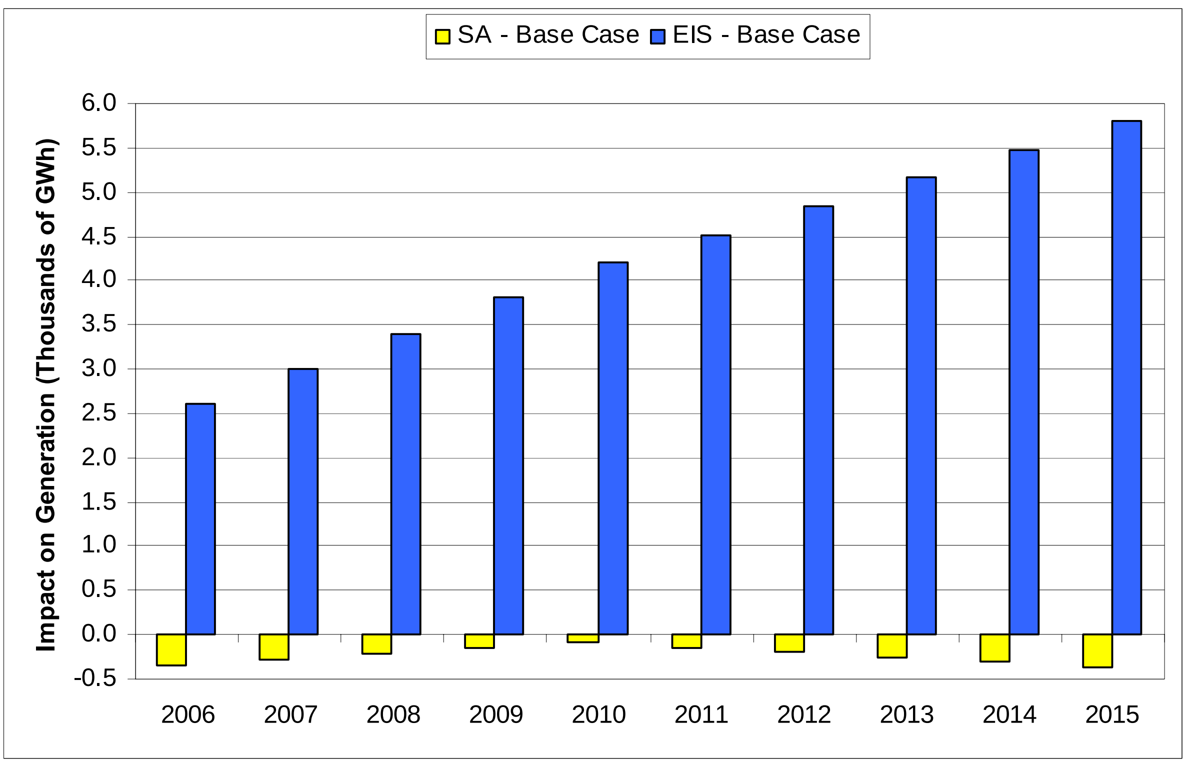
Impact (SA – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	(350)	113	(6)
2007	(284)	296	301
2008	(217)	480	608
2009	(151)	664	915
2010	(85)	848	1,222
2011	(142)	744	1,036
2012	(199)	640	851
2013	(256)	536	666
2014	(314)	433	481
2015	(371)	329	295

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

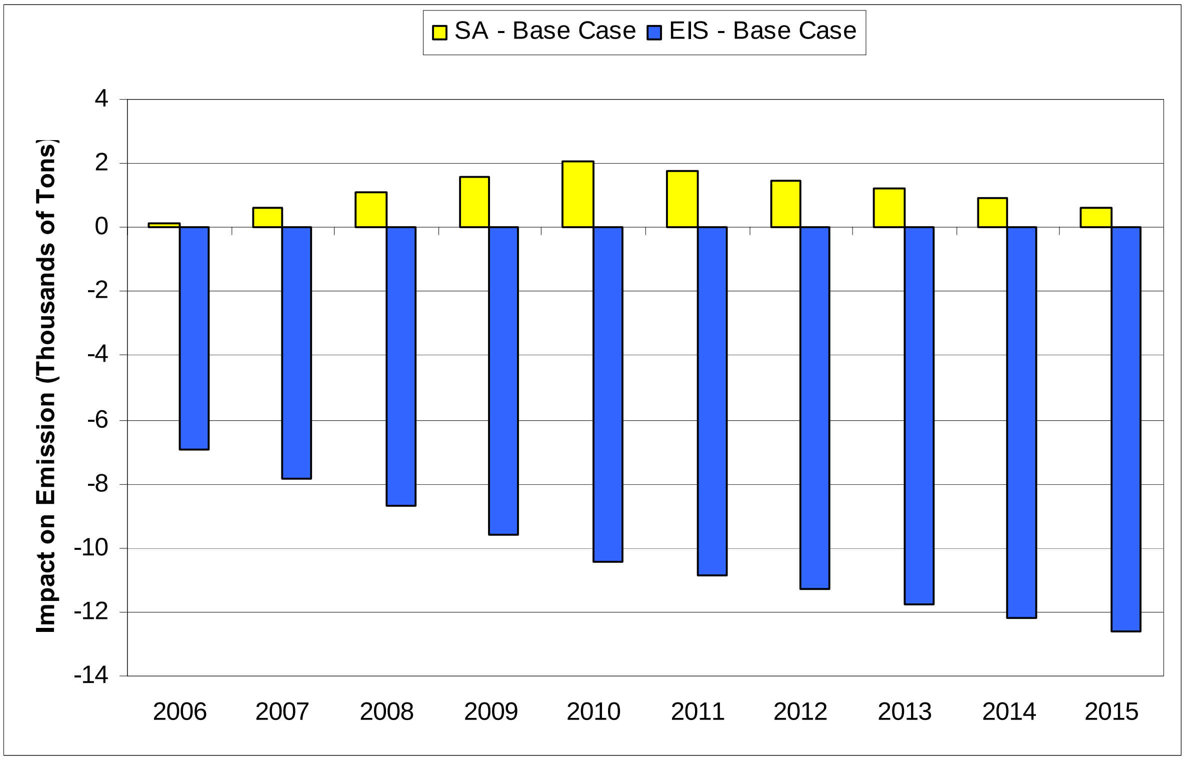


The simulations showed that generation within SPP would decrease were SPP to move from an RTO structure to a Stand-Alone structure in which wheeling rates would again exist between utilities that were previously SPP members. It is likely that with the added wheeling rates, the cost of production plus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

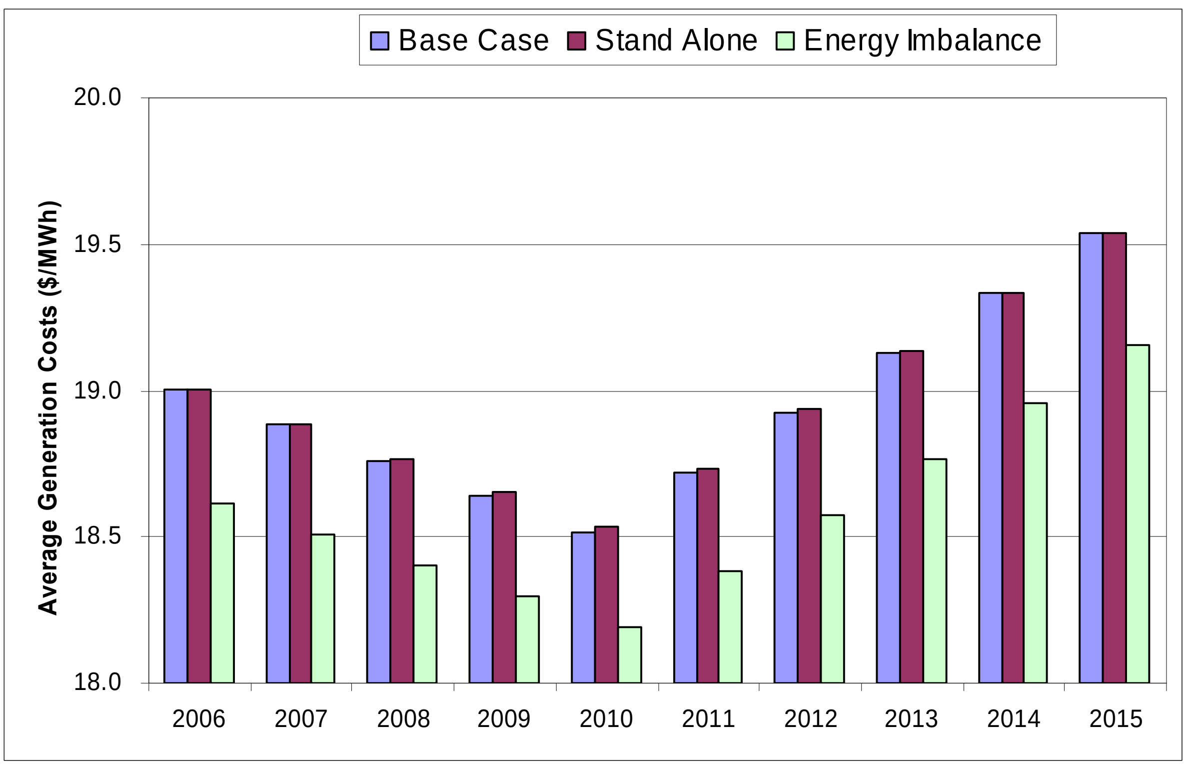
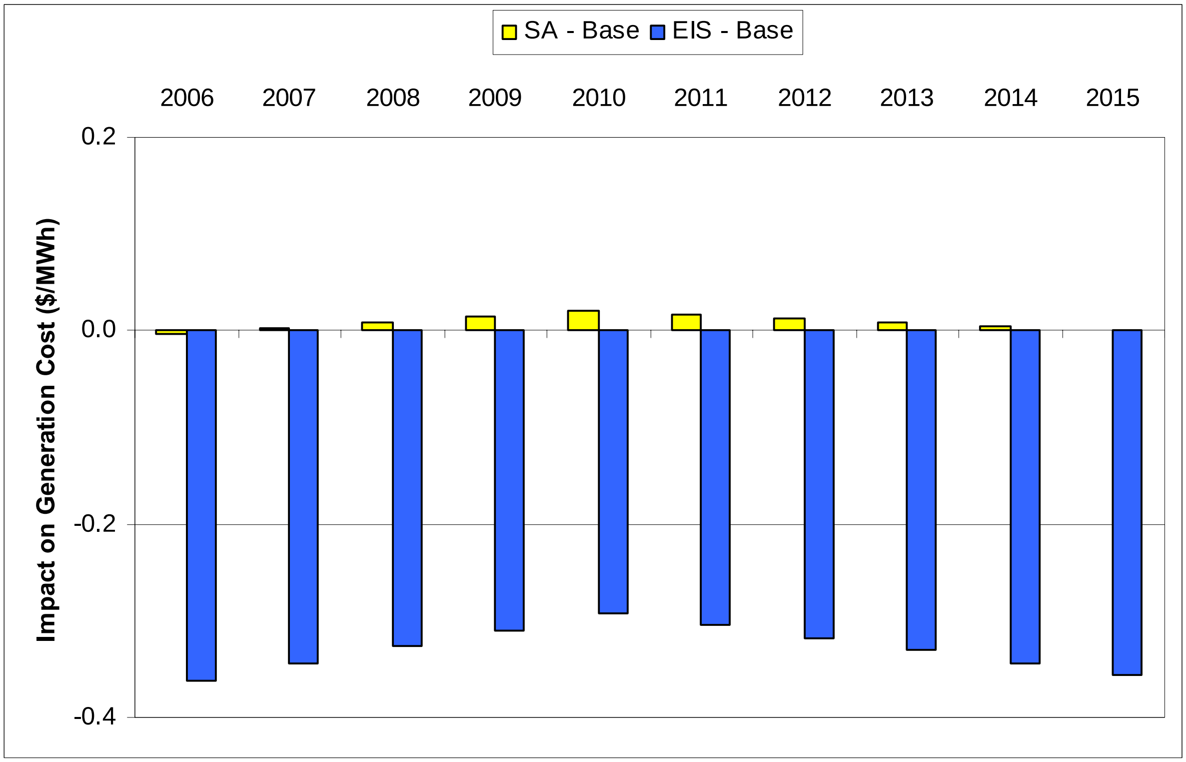


Figure 3-5 SPP Generation Cost ($/MWh) Differences



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

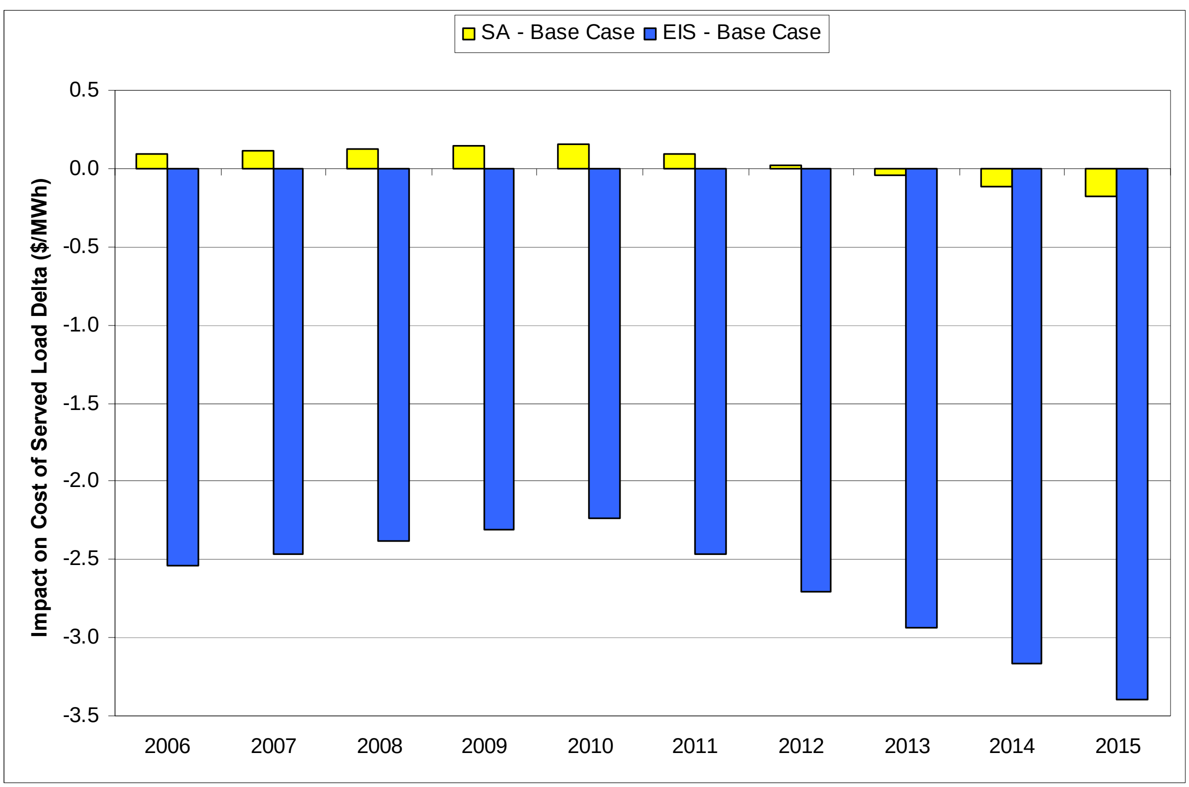
[26] The "spot price" refers to the locational price of energy (in $/MWh) as calculated under the locational marginal price (LMP) system, assuming cost-based, security constrained optimal dispatch of the system. While a spot price can be calculated for any point in the system, it is not generally reflective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

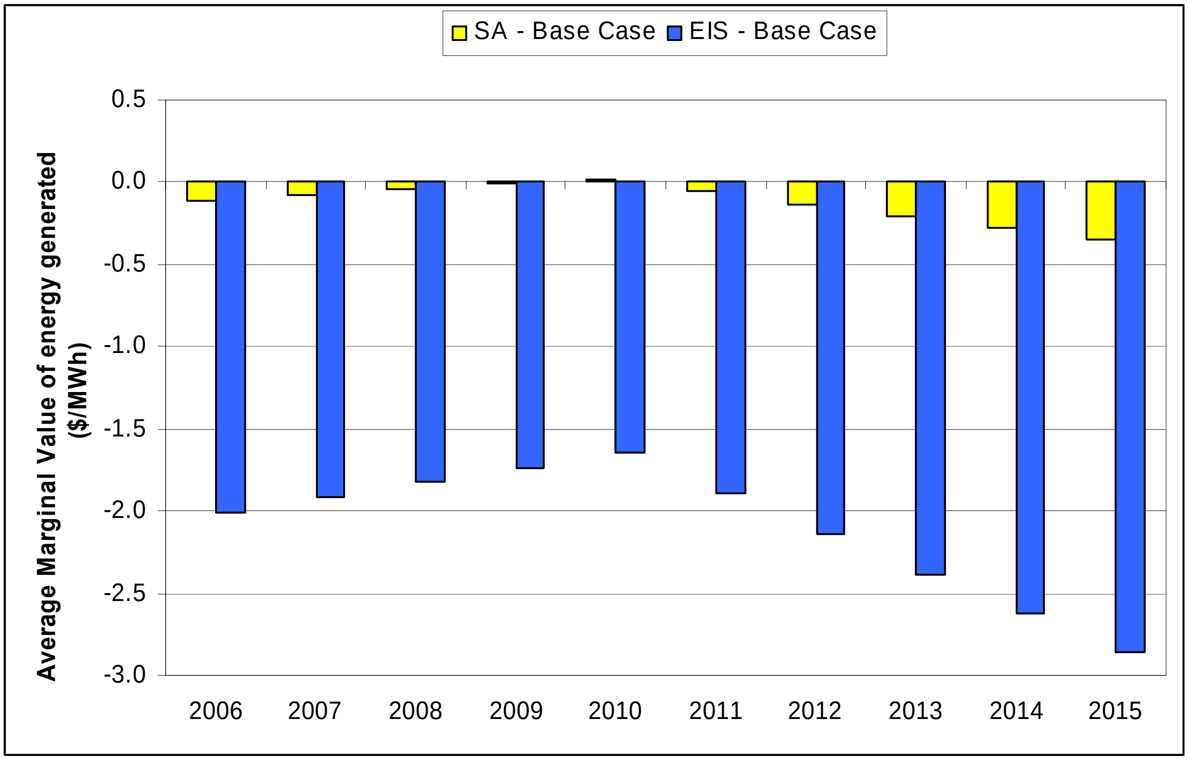
[27] Recall that the simulated values are based on the assumption that generating units bid marginal cost.

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.

Table 4-3 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

4.2.8.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-1. The additional cost of moving to stand-alone status for these four typical members is $4.7 million. The additional cost incurred by SPP merchants when SPP transmission owners under the SPP tariff move to stand-alone status is $8.6 million.

Table 1 in Appendix 4-1 also lists the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff. Considering only trade benefits and wheeling impacts, these utilities incur additional costs of $9.3 million when SPP transmission owners under the SPP tariff move to stand-alone status.

Finally, the rest of the Eastern Interconnect,[33] again considering only trade benefits and wheeling impacts, incurs additional costs of $30.5 million when SPP transmission owners under the SPP tariff move to stand-alone status. As shown in Appendix 4-1, Table 1, the total trade benefits and wheeling impacts across all companies is an additional cost of $53.8 million. As discussed above, this is exactly equal to the increase in production costs across the modeled footprint from the Base to the Stand-Alone case.

4.3 EIS Market Case Results and Discussion

4.3.1 Trade Benefits

Implementation of the EIS Market leads to a more efficient dispatch and thereby yields system-wide production cost savings in comparison to the Base case. Production costs savings for the entire Eastern Interconnect are $1,173 million over the study period. Production cost savings for the

[33] In the CBA the "Eastern Interconnect" includes the majority of the Eastern Interconnect, but excludes—for example—the Northeast markets.

transmission owners under the SPP Tariff are $2,569 million, while, in contrast, SPP merchants have a production cost increase of $2,670 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the trade benefits for the transmission owners under the SPP Tariff in the EIS Market case are $614 million. Thus, transmission owners under the SPP tariff obtain 52% ($614/$1173) of the total trade benefits.

Tables 3, 4 and 5 in Appendix 4-2 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.3.2 Transmission Wheeling Charges

No changes to wheeling rates from the Base case are assumed to take place in the EIS case. However, implementation of the EIS Market does change generation levels and tie-line flows. As noted above, the native load in each control area is assumed to pay the wheeling charges associated with the import of power. The wheeling charges decrease by $24 million over the study period for the transmission owners under the SPP Tariff. Since these are payments, this is a positive benefit to the EIS case. Table 6 in Appendix 4-2 gives annual wheeling charge increases by company over the study period.

4.3.3 Transmission Wheeling Revenues

Similarly, implementation of the EIS market changes also affects wheeling revenues. 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 decrease by $54 million. Since these are revenues, this is a negative benefit to the EIS case. Table 7 in Appendix 4-2 gives annual wheeling revenue increases by company over the study period. Since wheeling rates are unchanged between the Base and EIS market cases, the individual company wheeling impacts for the EIS market case are less affected by loop flow issues than those in the Stand-Alone case. With no change in wheeling rates and no intra-SPP wheeling rates, the loop flows will not significantly impact the change in wheeling impacts between the Base and EIS market cases if the loop flows into and out of SPP are similar in both cases.

4.3.4 SPP EIS Implementation and Operation Costs

SPP will incur considerable expenditures in implementing and operating the EIS market. These expenditures, in turn, will be assessed to the EIS market participants. An evaluation of the SPP budget was performed to project the costs that would be assessed to individual EIS market participants. For the transmission owners under the SPP tariff, the total cost that will be passed through by SPP is $104 million over the study period. Since this is an additional cost, this is a negative benefit to the EIS case. Table 8 in Appendix 4-2 gives the annual costs that would be assessed to EIS market participants.

4.3.5 Participant EIS Implementation and Operation Costs

EIS market participants will incur significant expenditures to participate in the EIS market over and above SPP's assessments for its own expenditures. In response to a request by CRA, EIS market participants provided a detailed annual estimate of the additional labor, O&M, and capital costs they would incur over the study period to participate in the EIS market. Appendix 4-4 gives details on these cost estimates. These costs were converted to annual revenue requirements and are summarized in Table 9 in Appendix 4-2. The total cost to transmission owners under the SPP tariff over the study period is $107 million. Since this is an additional cost, this is a negative benefit to the EIS case.

4.3.6 Total Benefits (Costs)

4.3.6.1 For Transmission Owners under the SPP Tariff

Table 4-4 shows the results by category in aggregate for the transmission owners under the SPP tariff. The aggregate benefit is $373.1 million over the study period.

Table 4-4 EIS Market 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

For each individual transmission owner under the SPP tariff, the total impact of moving to an EIS market is shown in Table 4-5. Table 1 in Appendix 4-2 gives results by company by category. While the aggregate benefit is positive, some companies show net additional costs. For those companies, the additional cost is driven by a relatively limited change in generation dispatch under an EIS market, which limits the accrual of trade benefits under the allocation method used in this study.

Table 4-5 EIS Market 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

4.3.6.2 By State

An allocation by state was performed for the six investor-owned utilities listed in Table 4-5 above. As noted above, 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. [34] Table 4-6 shows aggregate retail customer benefits (costs) by state for these six investor-owned utilities. Table 2 in Appendix 4-2 gives benefits by individual investor-owned utility by state. Again, 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.

Table 4-6 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

4.3.6.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-2. The collective benefit for these four typical members is $45.2 million without consideration of individual implementation costs, and this figure represents almost all of the remaining regulated generation for SPP members paying an SPP assessment.

The benefits to SPP merchants when the transmission owners under the SPP tariff form an EIS market are $123.9 million. The generation of the merchant plants is substantially greater in the EIS market case, and, as discussed above, merchants are attributed 50 percent of the trade benefits that accrue from their participation in the EIS market, with native load receiving the other 50 percent through contractual arrangements.

Table 1 of Appendix 4-2 gives the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff and do not pay an annual assessment to SPP. These entities are not part of the EIS as currently formulated, but will nonetheless be affected by the institution of the EIS. Only trade benefits and wheeling impacts were evaluated for these utilities, which have a collective benefit of $28.6 million.

[34] 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.

The balance of the Eastern Interconnect has a collective benefit of $382.6 million, again considering only trade benefits and wheeling impacts. Table 1 in Appendix 4-2 indicates that the total impact of trade benefits and wheeling impacts across all companies is $1,173 million. As discussed above, this is exactly equal to the decrease in production costs across the modeled footprint from the Base case to the EIS case.

5 Qualitative analysis of Energy Imbalance Market Impacts

This section explores impacts of SPP's implementing an Energy Imbalance Service (EIS) other than those impacts captured elsewhere in this report. (Section 3 addresses the potential energy market impacts that were determined quantitatively; Section 4 addresses expected SPP and market participant costs as part of the allocation.)

This assessment was made by comparing the existing imbalance energy provisions contained in SPP's Open Access Transmission Tariff with the filed tariff provisions and draft protocols describing the Imbalance Energy (IE) market. The following reference documents were relied upon:

Existing Settlement Provisions:

- Open Access Transmission Tariff (OATT) for Service Offered by the Southwest Power Pool, November 1, 2000
- Revised, SPP Board Approved, OATT Section 3 and Schedule 4-A
- Transmission Owner Tariff provisions for Imbalance Energy Settlement, as summarized by SPP staff, November 2004

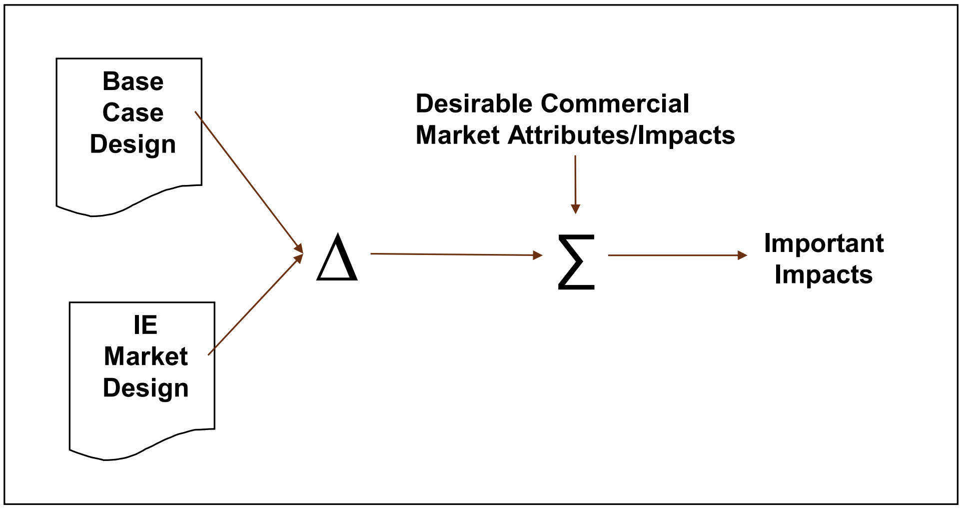
Future-State (EIS) Market Provisions:

- SPP Market Protocols (Draft) v2, January 6, 2005
- RTO Proposal of Southwest Power Pool, Inc., Volume I, October 25, 2003
- Market Working Group Meeting materials - various

5.1 Methodology

Figure 5-1 shows the general approach to assessing qualitative impacts associated with the EIS.

Figure 5-1 EIS Qualitative Assessment Methodology



Generally the existing and proposed EIS market designs were compared to identify significant design changes and underlying drivers of those changes. After a preliminary consideration of the potential impacts of the Significant Design Changes on SPP and the market participants, CRA grouped the potential impacts into nine categories of C*ommercial Impacts*, which are listed and briefly described in Table 5-1.

The subsections that follow present the significant design changes and underlying drivers, followed by the Commercial impacts.

Table 5-1 Commercial Impacts

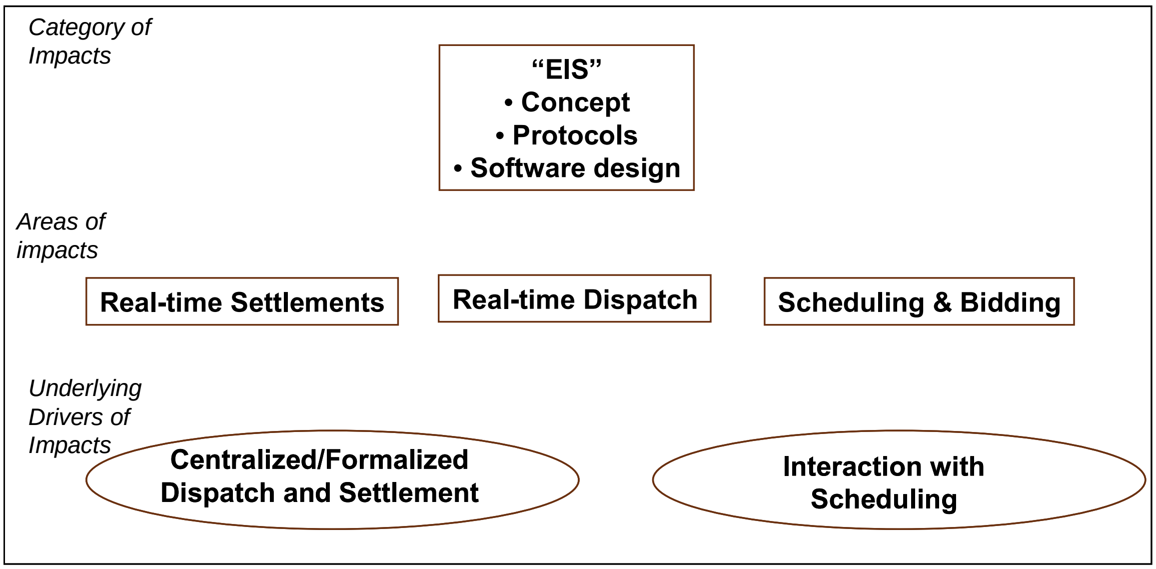
Commercial Impact	Illustrative Description
1. [Facilitate Development of] **Competitive Markets**	Does the Significant Design Change facilitate or hinder competition or market penetration (the ability of new retailers to compete for load)—for example, through complexity, volatility or cost shifting?
2. [Minimize] **Discriminatory Environment**	Does the Significant Design Change reduce perceived or actual barriers that unduly discriminate against small/large players, non-incumbents, etc.?
3. [Increase] **Efficiency of Production**	Does the Significant Design Change encourage the efficient use (dispatch, commitment) of existing facilities and/or promote economic efficiency in the consumption of electricity? (This considers microeconomic principles and also incorporates maximization of social welfare—the sum of consumer and producer surplus.)[35]
4. [Promote] **Efficient Resource Expansion**	Does the Significant Design Change provide proper incentives for resource investment (including Distributed Generation and Demand-Side Management)? This includes the need for site-specific pricing and resource siting signals, and changes in risk and/or uncertainty associated with nodal pricing.
5. [Promote] **Efficient Grid Expansion**	Does the Significant Design Change encourage or discourage investment in the grid by various entities? At the right locations? With the proper trade-offs between wires and resources/Demand Side Management?
6. [Neutralize] **Opportunities to Exercise Market Power**	Does the Significant Design Change increase or decrease the need for mechanisms to mitigate potential abuse of market power?
7. [Enhance] **Grid Reliability**	Does the Significant Design Change recognize the physical realities of the grid, reduce burdens on grid operators, and reduce the potential for (uneconomic) loss of load?
8. [Facilitate] **Ability to Conduct Business**	Does the Significant Design Change make it easier for entities to participate in the SPP market?
9. [Minimize] **Costs and Administrative Burdens**	Does the Significant Design Change reduce or increase costs (that are not already accounted for in the IIA) and burdens on market participants and on SPP?

[35] Note that this metric, as described, reflects Social Welfare generally. However, various impacts tend to affect producer surplus or consumer surplus. Given that which of these may be impacted may be relevant to various stakeholders (and it is not the consultant's role to judge the merits of how the social welfare is experienced), the discussions within the text identify, where possible, how the efficiency gains are expected to be experienced (for example, when Load Serving Entities are better off).

5.2 Market Rule Changes

While the EIS primarily relates to the settlement of imbalance energy, instituting a formal locational balancing energy has additional impacts. These impacts can be viewed on several levels, as shown in Figure 5-2.

Figure 5-2 EIS Changes - Various Views



There are several areas of impacts, and these have some common underlying drivers. The impact areas considered can be summarized as follows:

Real-time market: Impacts of Settlement using Locational Imbalance Pricing (LIP)

The most direct and obvious impacts related to instituting a formal Imbalance Energy market with locational pricing are associated with the changed settlement rules and processes; they include the impacts on loads and on generators of the change in pricing and settlement processes. For example, with the EIS:

- SPP manages, in a centralized way, settlements for inadvertent energy that were previously conducted bilaterally with each Control Area Operator (CAO).
- CAOs settle imbalance energy for load formally with SPP rather than simply load following or settling with neighboring control areas.
- Pricing between supply sources may be different than pricing of load.
- New metering reporting and management requirements are created.

While the fundamental impacts of the pricing changes are addressed in the MAPS modeling aspect of this study, and the infrastructure costs are addressed specifically, the movement to a formal EIS creates other non-monetized impacts.

Real-time: SPP Real-time Resource Deployment

In addition to the financial implications of LIP energy settlement, the EIS design includes the centralized optimization and dispatch of balancing energy sources. This creates the need for specific infrastructure from SPP, and likely for members, and it may substantially change the operational management of generator units in real-time. Each CAO no longer optimizes and deploys resources to balance its own system; instead, generation operators submit bid curves to SPP, which optimizes the balancing energy resources using a Security-Constrained Economic Dispatch (SCED) algorithm and (for units providing balancing energy) determines which units generate to what levels in real-time—providing formal dispatch notices.

Forward Market Impacts: Schedules and Bid Impacts

Given that the EIS creates the need for formal communication of system conditions and of individual participants' expected behavior and input data, the implementation of the EIS creates additional forward scheduling requirements. To operate an EIS, SPP needs specific and timely resource plan information. SPP will use a baseline of forward load and generation schedules as an allocation basis over which to allocate the financial results of the EIS market. Thus, the EIS creates different forward market requirements and may have different settlement impacts related to activities in the forward market. Application of uninstructed deviation charges or penalties to scheduled-to-real time difference and the use of the EIS to manage Firm schedules are examples of these types of impact. In some cases, these impacts are more significant during the period when there will be a locational market-based real-time congestion management system, but no forward congestion management system.[36]

5.3 Underlying Drivers

There appear to be two underlying drivers for the areas of impact just described, and these are essentially operational in nature:

1. Centralized/formal control of real-time balancing

   This driver relates to both operational control and pricing control and seems to be the strongest.

2. Relationship of real-time EIS coupled with scheduling

   The ultimate impacts are considered in the sense of these two underlying drivers.

5.4 Impacts of Underlying Drivers

This discussion presents those commercial impacts resulting from the fundamental drivers.

[36] For example, the issue of overscheduling or under-scheduling counterflow likely falls into this category in the sense that if SPP had a comparably-based congestion management system in the Day Ahead there would be more naturally balancing incentives for scheduling.

Facilitation of Competitive Markets

The long-run impacts of implementing a formal nodal EIS are expected to include improved transparency and improved price signals, and experience in other markets suggests that these will be the predominant impacts. Complexity produces adverse impacts during a transition period—for example, when parties are affected by locational balancing EIS prices yet do not have the operating history of what these prices and respective points' price spreads might be. Such impacts are expected to be alleviated with operating stability and history. That is, the market will eventually establish a pricing history that will provide market participants data reflecting expected pricing risks.

Applying explicit imbalance energy prices creates risks associated with not following schedules. The relative impact depends on the details of what is in place today regarding imbalance energy settlement with the CAOs. Whether the implementation of any test for schedule feasibility[37] when used in isolation without a formal day-ahead or hour-ahead congestion management market, will enhance or impede the competitiveness of the market depends on the effectiveness of the particular mechanisms implemented. Similarly, to the extent that the new centralized LMP algorithms or SCADA systems do not work correctly, there will be adverse impacts on the market until those issues are resolved.[38]

Market monitoring provisions offer the potential for more competitive markets, provided that they are not overly burdensome and that they do not create undue regulatory risk.

Minimize Potential Discriminatory Behavior

The movement to an explicit EIS should increase transparency, which would reduce the potential for discriminatory behavior and improve the competitiveness of markets generally.

Efficiency of Production

The production efficiency impacts of the EIS are measured by the MAPS modeling. To the extent that the EIS is cleared as efficiently as the model assumes, the numerical modeling results are expected to reflect the EIS benefits. To the extent that bilateral schedules do not directly reflect the efficient dispatch, and to the extent that the EIS is not used to manage congestion for the bilateral schedules, the predicted benefits may not be realized.

The movement with the EIS to the centralized management of inadvertent energy will likely have added production efficiencies that are not captured in the quantitative results of the MAPS modeling.[39]

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[37] Note that some of the market design documents have contemplated the possibility that a "feasibility" test for schedules may be necessary to implement a workable real-time EIS. How "feasibility" will be determined, however has not yet been specified.
[38] That SPP intends to have policies related to the quality control and improvement of the EIS algorithms and SCADA systems is seen as a positive indication that any adverse software impacts will be minimized.
[39] The MAPS modeling assumes in all cases that inadvertent energy management is perfectly efficient at the seams of SPP, other than the financial effect of the boundary wheeling rates.

Resource Expansion

Location-specific and transparent pricing at nodes should provide improved price signals for siting. In other markets that CRA has observed, however, institutional barriers have emerged that prevented the market from responding appropriately to such price signals. These barriers include exogenous factors (e.g., NIMBY) that continue to have strong influences, and other market structures—such as capacity market implementation—that may dampen the price signals that are needed to overcome other factors. While specific nodal price signals should be beneficial, realizing their full benefit may take time while such other market structures are modified.

Grid Expansion

The implementation of the EIS is not likely to significantly improve grid planning or expansion. This is because long-term transmission investments must be justified primarily on the basis of anticipated future demand and long-term projections of future costs, rather than on specific historical uses and congestion costs. Most planners already use nodal information to determine the most appropriate transmission upgrades, so that the EIS nodal pricing for balancing energy seems to provide no direct advantage or disadvantage in the area of grid expansion.

Market Power

This study did not include an assessment of the propensity for any participant to exercise market power. One might expect that the EIS would reduce the ability to exercise vertical market power, given that SPP will be operating the EIS market. Participants may fear, however, that the ability to exercise horizontal market power might be greater, or perhaps more specifically that the consequence of the exercise of horizontal market power might be higher given that marginal pricing—as opposed to average pricing or returning “in-kind” energy for example—may have large pricing impacts in the EIS. While these factors are at play, it is not possible to determine whether the resulting impact, combined with the impacts of a market monitoring plan, would be positive or negative overall.

Grid Reliability

The grid is operated reliably today and it will be operated reliably under an EIS. This issue therefore addresses whether there are any factors that provide marginal additional levels of reliability. Here again balancing factors are likely at play. The movement to an SPP centralized real-time dispatch and balancing should afford more visibility and a broader perspective than does individual control area operations. This is a plus. At the same time, however, movement away from CAO balancing creates the possibility that specific knowledge of local grid issues will be lost over time. This loss of expertise is a disadvantage of the EIS in the sense of margins of reliability. Further, the EIS may result in exercise of the generation system in manners not previously experienced[40] and the centralized dispatch of resources may result in more rapid movements that require more regulation control. To the extent that this effect is strong, the reliability margin may be somewhat reduced.

It is not clear that either of these offsetting effects is significantly stronger than the other.

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[40] For example, with the fluid participation of independent generator resources in the EIS, the dispatch of the system will change; in addition, CAOs’ regulation units will no longer be operated in conjunction with the CAO-controlled deployment of balancing energy resources.

Ability to Conduct Business and Administrative Burdens

This study quantitatively captures the costs to participate in the EIS. Both costs to SPP and costs to market participants are estimated. However, it is possible that these costs—especially those born by market participants—are not captured consistently across all market participants. Costs that may be outside the quantified values may include, for example, costs of increased scheduling needs, utilities' costs of hedging new EIS risks, and the costs of regulation unit owners associated with the price risk of regulation energy (the energy provided by the regulating units in real-time in response to frequency-control signals) relative to EIS energy. Similarly, parties that have in the past settled real-time imbalances with one more control areas will be relieved of the administrative costs of performing those settlements. It is not clear whether such costs were included in the quantifications of EIS costs.

5.5 EIS Qualitative Analysis Summary

Overall, it is expected that implementation of the EIS will create additional transparency and efficiency benefits. However the EIS will also increase administrative burdens, though it is likely that a significant fraction of these additional burdens will be transitional, meaning that they will return more or less to today's level once the EIS has been in place for some time (roughly 1 to 3 years). Further, it is likely that the administrative and infrastructure costs borne by participants for the EIS will be "lumpy," in the sense that allowing for the EIS requires significant infrastructure much of which will be useable also for the full day-ahead market and congestion management process if, and when, it is implemented.

6 Qualitative Analysis of Market Power Impacts

The SPP Regional State Committee has asked CRA to address market power issues that might arise in the context of the implementation of the EIS market, in particular. The question is whether the EIS market would provide an increased opportunity to exercise market power on the part of one or more owners of generation resources in the area. In this context, it is useful to recall that market power is the ability and incentive to increase market prices by a significant amount for an extended period. In particular, a generation owner must have both the ability and the incentive to exercise market power in order to be considered as possessing market power at all, regardless of whether it actually exercises that market power.

6.1 Market Monitoring

Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. As part of the institution of an EIS market, SPP will implement a market monitoring process that includes the appointment of an independent contractor to oversee the safe and reliable operation of SPP's transmission system.

The principal functions of SPP's market monitoring process are the following: reporting on compliance and market power issues relating to transmission services, including compliance and market power issues involving congestion management and ancillary services; evaluation and recommendations respecting any required OATT revisions, standards or criteria; ensuring that market monitoring is performed in an independent manner; developing procedures to inform government agencies and others with respect to market activities; monitoring market behavior and market participants to determine whether any activity is constraining transmission or excluding competitors; and ensuring the non-discriminatory provision of transmission service by SPP.

SPP has proposed a Market Monitoring Plan intended to provide for the monitoring of SPP's market and for the mitigation of the potential exercise of horizontal and vertical market power by market participants. The plan will be implemented and maintained by two Market Monitors: a Market Monitoring Unit (MMU) internal to SPP, and an Independent Market Monitor (IMM).

The MMU has primary responsibility for implementing the Plan, with the advice and oversight of the IMM, by (a) continuously monitoring SPP's markets and services provided under SPP's OATT, (b) implementing approved market mitigation measures, (c) taking the lead in investigations and in compliance and corrective actions, and (d) collecting and retaining relevant data and information.

The IMM has several responsibilities. Among these, the IMM: (a) develops, reviews, and recommends updates to the monitoring and mitigation procedures and supports SPP in obtaining FERC approval for such procedures, (b) suggests revisions to the SPP market design and procedures, (c) advises the MMU and monitors its activities, (d) advises the SPP Board, and (e) periodically reports on SPP's market and services.[41]

Together, the SPP MMU and the IMM will monitor SPP's markets and services by analyzing market data and information such as the following: resource and ancillary service plans, schedules and offer curves submitted for generating units; commitment and dispatch of generating units; locational

[41] SPP Market Monitoring Plan, OATT Attachment, Draft 11/8/04

imbalance prices; control area data (e.g., net scheduled interchange, actual net interchange, and forecasts of operating reserves and peak demand); transmission services and rights (e.g., ATC, AFC, tariff administration, operation and maintenance of the transmission system, markets for transmission rights, and reservation and scheduling of transmission service); transmission congestion; and settlement data.[42]

Market participants or government agencies may submit confidential complaints or requests for investigation to the MMU or the IMM. The MMU and/or the IMM may engage in discussions to resolve issues informally, may issue demand letters requesting market participants to discontinue actions as necessary to achieve mitigation and/or compliance, and may implement any FERC-approved mitigation measure. A process is also in place for the MMU or the IMM to recommend changes in market design or procedures as needed to ensure just and reasonable prices. The IMM will publish annual state-of-the-market reports and quarterly reports on instances of market power, if any. The IMM will also provide an annual review of the activities of the MMU.[43]

SPP estimates that market monitoring will cost about $1 million per year, or about $0.005 per megawatt-hour of net annual energy for the SPP region.

6.2 Generation Market Power

CRA has not conducted a formal, quantitative review of the potential impact of the SPP Energy Imbalance Market on the likelihood that market power might be exercised in the generation market within SPP. Such an assessment would be hypothetical and difficult to quantify given the uncertainty concerning future economic conditions and future market behavior of participants.

In CRA's view, the implementation of the Energy Imbalance Market, by itself, is unlikely to increase significantly the likelihood of actual exercises of market power in the SPP generation market. This is because most power delivered within SPP will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners in SPP would have little, if any, incentive to withhold generation from the SPP Energy Imbalance Market for the purpose of increasing the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, which would be lacking under cost-based regulation and long-term contracts, the issue of market power is likely to be a minor consideration under the SPP market conditions.

Nonetheless, it is important that the SPP Market Monitoring Unit and the SPP Independent Market Monitor review the performance of the SPP Energy Imbalance Market and report their findings to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

Given the underlying economic fundamentals of regulation and long-term contracting in the SPP area, and SPP's plans for active and ongoing monitoring of the market, CRA believes that the potential for the exercise of market power in the SPP Energy Imbalance Market is not likely to be significant and

[42] Ibid.
[43] Ibid.

should not be considered a significant risk in the implementation of that market. We have not reviewed the costs versus the reduced-risks/benefits of the market monitoring function itself given that this function is required under current FERC guidelines in any case.

7 Aquila Sensitivity Cases

7.1 Aquila Sensitivity Cases—Methodology

The Aquila Sensitivity cases measured the wholesale energy modeling impact of Aquila being a part of SPP rather than of the MISO RTO during the simulation year 2006. In the balance of the study's wholesale energy modeling, Aquila was assumed to be part of MISO. The Base and EIS cases were simulated.

Aquila consists of two control areas, which in the study are designated as Missouri Public Service (MIPU) and WestPlains Energy (WEPL). To simulate the configuration of SPP with Aquila as a member, the following changes were made to the cases:

- **Wheeling rates.** Wheeling rates between Aquila and other SPP areas were eliminated, while wheeling rates were instituted between Aquila areas and MISO.
- **Reserves.** Because of the formula used to calculate reserve requirements in SPP (largest contingency plus one-half the next largest contingency) the total reserve requirements for SPP do not change between the two cases. With Aquila as a member, however, this requirement is spread over a greater load base, so the reserve requirement for each individual member company is reduced. Because MISO reserves are met on a system-wide basis as a percent of load, the total reserve requirement in MISO is also reduced if Aquila becomes part of SPP. (Though the average load share of reserves in MISO would remain the same.)
- **Commitment.** In the Aquila sensitivity case, units in WEPL and MIPU are committed against load in SPP.

Wholesale energy results were generated for the Aquila case for both the Base and EIS cases. No specific analysis of cost or benefit allocation (such as the allocations described in Section 4) was performed for the Aquila cases.

7.2 Aquila Sensitivity Cases—Results

This section presents the results of the Aquila sensitivity runs. Results are presented such that readers can both compare the impacts for either case (Base or EIS) of Aquila being part of MISO or of SPP, and also see the extent to which the benefits of the EIS case are sensitive to Aquila being in MISO or SPP.

Table 7-1 shows results for the combined SPP and Aquila footprint[44] for four fundamental physical and financial metrics:

- Generation
- Average per MWh generation cost
- Total generation cost, normalized to the generation levels of the Aquila in MISO, Base case
- Average regional spot price of energy

[44] For a consistent comparison, the results are shown inclusive of Aquila regardless of whether Aquila is in SPP or MISO.

Table 7-1 SPP and Aquila Regional Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation in SPP + Aquila (GWh)	204,865	206,637	(1,772)	207,406	209,422	(2,016)	2,541	2,785	(244)
Average Generation Cost ($/MWh)	$ 19.07	$ 19.12	$ (0.05)	$ 18.68	$ 18.74	$ (0.06)	$ (0.39)	$ (0.38)	$ (0.01)
Normalized Generation Costs ($million)	$ 3,907	3,917	$ (10)	$ 3,827	3,839	$ (12)	$ (80)	$ (78)	$ (2)
Per MWh Spot Energy Cost	$ 40.59	$ 40.75	$ (0.16)	$ 38.10	$ 38.35	$ (0.26)	$ (2.49)	$ (2.40)	$ (0.09)

The simulations indicate that the region generates more if Aquila is located with SPP than it does if it is located within MISO under both the Base and EIS cases. Regional generation costs are simulated to be $10 million to $12 million lower if Aquila is in MISO, roughly 0.25% of the region's total generation cost. Spot marginal energy costs are expected to be $0.16/MWh less expensive with Aquila in MISO under the Base case and $0.26/MWh less expensive under the EIS case.

The column entitled EIS-Base, Difference (MISO-SPP) indicates, as shown by the relatively small values for each metric, the benefits of the EIS market for the region as measured in the modeling is not particularly sensitive to whether Aquila is in MISO or SPP.

Table 7-2 shows the impact similar to Table 7-1 on the Aquila companies only.

Table 7-2 Aquila Companies' Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation Aquila (GWh)	6347	6295	52	6280	6307	(27)	(67)	12	(79)
Average Generation Cost Aquila ($/MWh)	$ 21.07	$ 20.80	$ 0.27	$ 20.79	$ 20.71	$ 0.08	$ (0.28)	$ (0.09)	$ (0.19)
Normalized Generation Costs Aquila ($million)	$ 133.72	$131.99	$ 1.73	$ 131.94	$131.43	$ 0.50	$ (1.79)	$ (0.56)	$ (1.22)

Table 7-2 indicates several characteristics of the Aquila impacts as given by the modeling:

- Aquila companies generate more if in MISO under the Base case, but more if in SPP if SPP has an Energy Imbalance market. (In both cases the change in Aquila generation is less than 1%).
- Based on generating costs, Aquila shows benefits of being a member of SPP, and those benefits are higher under the Base case than under the EIS case (1.3% and 0.3%, respectively)

Also notable from the information shown in Tables 7-1 and 7-2 is that while the SPP region's generating costs would be lower with Aquila in MISO ($10 million in the Base case), Aquila's generating costs would be lower with Aquila in SPP ($1.7 million in the Base case).

Table 7-3 shows the impact on NOx and SOx emissions. As with the generation costs, the impacts to the Aquila emissions behave opposite to that of the SPP region to whether Aquila is in SPP or MISO, and in this sense the impacts on emissions between Aquila and SPP are somewhat offsetting. In either case the impact to SPP or to Aquila is approximately a 1% change in emissions.

Both Aquila companies show benefits from being in SPP. Under both the Base and EIS cases, the generator net revenues for MIPU are higher if Aquila is in SPP ($2 million for the Base case, $2.7 million for the EIS case), but the load energy costs are lower if MIPU is in SPP ($2.6 million for the Base case, $2.2 million for the EIS case).

For WEPL, the magnitude of the increase in generation net revenues when WEPL is part of SPP is lower than it is for MIPU ($0.8 million for the Base case, $1.4 million for the EIS case). The impact to load is comparable, a saving if part of SPP of $2.4 million in the Base case, $2 million in the EIS case. Note that the energy cost impact for WEPL is a savings of approximately $1/MWh if Aquila is in SPP. This relatively significant savings is due to the fact that WEPL is entirely within the SPP footprint (as opposed to MIPU, which borders to some extent MISO).

Table 7-3 Emission Impacts of Aquila Cases

	Base Case			EIS Case			EIS - Base		
	NOx Emissions (Tons)			NOx Emissions (Tons)			NOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	283,538	286,624	(3,086)	276,929	279,640	(2,711)	(6,608)	(6,984)	376
Aquila Companies	18,477	18,297	180	18,243	18,296	(52)	(233)	(1)	(232)
Total SPP+ Aquila	302,014	304,920	(2,906)	295,173	297,935	(2,763)	(6,842)	(6,985)	143

	Base Case			EIS Case			EIS - Base		
	SOx Emissions (Tons)			SOx Emissions (Tons)			SOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	449,349	454,883	(5,535)	449,010	453,982	(4,971)	(338)	(902)	563
Aquila Companies	22,173	22,102	71	22,049	22,144	(95)	(124)	43	(166)
Total SPP+ Aquila	471,521	476,985	(5,464)	471,059	476,126	(5,067)	(462)	(859)	397

Appendices 1-1, 1-2, 2-1, 3-1, 3-2, and 3-3

Appendix 1-1: Roster of SPP Regional State Committee (RSC)

RSC President:	Denise Bode Chairman, Oklahoma Corporation Commission
RSC Vice-President:	Sandra Hochstetter Chairman, Arkansas Public Service Commission
RSC Secretary:	Julie Parsley Commissioner, Public Utility Commission of Texas
RSC Member:	Steve Gaw Commissioner, Missouri Public Service Commission
RSC Member:	Brian Moline Chairman, Kansas Corporation Commission.

Appendix 1-2: Roster of SPP RSC Cost Benefit Task Force

Members:

Sam Loudenslager, Arkansas Public Service Commission * *Chairman*
James Watkins, Missouri Public Service Commission
John Cita, Kansas Corporation Commission
Ken Zimmerman/Joyce Davidson, Oklahoma Corporation Commission
Jess Totten, Public Utility Commission of Texas

Richard Spring, Kansas City Power & Light **Vice-Chairman*
Michael Desselle, American Electric Power
Darrell Gilliam, Southwestern Power Administration
Shah Hossain, Westar Energy
Robin Kittle, Xcel Energy
Mel Perkins, Oklahoma Gas and Electric

Jeffrey Price, Southwest Power Pool * *Secretary*

Associate Members:

Ryan Kind, Missouri Office of Public Counsel
Les Dillahunty, Southwest Power Pool

Others Actively Participating:

Burton Crawford, Kansas City Power & Light
Terri Gallup, American Electric Power
Bernard Liu, Xcel Energy
Alan Myers, Aquila
Rick Running, Southwest Power Pool
Mike Sheriff, Oklahoma Gas and Electric
Bary Warren, Empire District Electric Company

Appendix 2-1 Cost-Benefit Studies in Electric Industry Restructuring

Starting in the 1970s and continuing through the 1990s, a number of studies attempted to evaluate, by simulation and other means, the various benefits expected to arise from increased competition and the restructuring of the U.S. electric utility industry.[1]

On December 17, 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000 mandating that utilities join an RTO with certain minimum characteristics. FERC next proposed the creation of a set of RTOs, and in 2001 it commissioned a cost-benefit analysis of RTOs and their markets.[2] This was the first of a wave of specific studies on the benefits and costs of RTOs.[3] This section briefly surveys six of these studies[4] (references for these studies are listed in Appendix 2-2.

1. The ICF FERC Study
2. The CAEM PJM Study
3. The PJM Northeast RTO Study
4. The TCA RTO West Study
5. The CRA SEARUC Study
6. The CAEM PJM Study
7. The TCA ERCOT Study

These studies, summarized in Table 2-1, differ in a number of important respects, addressing different policy questions and comparing market restructuring at various stages of integration. Central to the comparison of these studies is the question being addressed. The ICF FERC study addresses the national policy question "Should we encourage RTO development?" The CRA RTO West and CRA SEARUC studies address the forward-looking benefits of initial new RTO formation. The PJM Northeast RTO Study addresses the integration of existing operational Independent System Operators (ISOs) and RTOs. The CAEM PJM Study is a historical retrospective study, and the TCA ERCOT Study examined a nodal market structure.

[1] See the recent summary by Michaels (September 2004).
[2] ICF FERC Study.
[3] The CRA SEARUC Study, p. 97, has an appendix providing a detailed comparison of six different RTO studies.
[4] In addition to these, two additional studies are under way: one focusing on impacts of stages of RTO Implementation in the WestConnect region, and the measurement of benefits of SPP RTO as well as the measurement of potential benefits of implementing an Energy Imbalance market in that region.

This SPP CBA is similar to those past studies in one respect, namely in its consideration of movement from an RTO structure (the Base case) to the Stand-Alone case: the PJM NE RTO, TCA RTO West, and CRA SEARUC studies assessed the impacts of movement to an RTO.

The analysis of the implementation of the Energy Imbalance market in this CBA is unique in that it isolates impacts of the increased access to the transmission system by non-network resources in addition to measuring the impact of improved management of congested lines under a centralized market.

CHARLES RIVER ASSOCIATES

Table 1 Comparison of Select Industry Cost-Benefit Studies

	ICF FERC Study	PJM NE RTO Study	TCA RTO West Study	CRA SEARUC Study	CAEM PJM Study	TCA ERCOT Study
Market Focus	Nationwide	Integration of NE RTOs	RTO West (and impacts on rest of WSCC)	Formation of multiple sub-region RTOs	Historical examination of PJM benefits	ERCOT energy market
Key Issue Addressed	Economic benefits of FERC RTO Policy change	Economic benefits of ISO and RTO integration	Economic benefits of RTO formation	Economic benefits of RTO formation and coordination	Benefits of PJM RTO in historical context	Impacts of movement to a nodal market design
Benefits	Improvements in transmission system operations, inter-regional trade, congestion management, reliability and coordination; improved performance of energy markets, including greater incentives for efficient generator performance; and enhanced potential for demand response.	Improvements in production cost	Improvements in dispatch with reduction in transmission rate "pancaking"	Improvements in production cost, reflecting implications of transmission funding/ tariff alternatives	Benefits in wholesale, retail, capacity, and demand response markets, based on assumptions that restructuring dominated the price changes in the period and thus illustrate the benefits	Improvements in the ability to manage congestion given resource-specific bidding and scheduling, congestion pricing and generation siting
Costs	RTO formation cost	Cost of RTO/ISO integration	RTO formation costs	RTO formation costs	—	Infrastructure costs
Net Benefit Treatment	No separation of producer surplus gains/losses from consumer surplus impact	Total production cost less formation/integration cost	Gains/losses in producer and consumer surpluses	Native load benefits	Change in consumer surplus; rejects consideration of producer surplus impact	Gains/losses in producer and consumer surpluses less cost impacts
Sub-regional impacts	—	Included	Included	Included	PJM and adjacent states	Included

	ICF FERC Study	PJM NE RTO Study	CRA TCA RTO West Study	CRA SEARUC Study	CAEM PJM Study	TCA ERCOT Study
Long-run benefits	Estimates of improved generator efficiency and demand response	—	—	—	—	Generator Siting
Time Horizon	Forecast 2002–2021	Two years forecast, 2005 and 2010	Single-year forecast, 2004	Forecast 2004–2013	Historical analysis 1997–2002	2004-2014
Primary methodol-ogy	Nationwide LP simulation of power system, fuel markets, and environmental limitations	MAPS generation and transmission modeling	MAPS generation and transmission modeling	MAPS generation and transmission modeling	Ad hoc historical analysis	MAPS generation and transmission modeling, Rate impact allocation sharing trade benefits
Treatment of constraints reduced by shift in policy	Mostly technological change	—	Specific treatment of institutional changes and impact on dispatch	Specific treatment of institutional changes and transmission tariff development	—	Specific treatment of institutional changes and impact on dispatch
Key Conclusion s	Substantial but uncertain benefits from RTO development	Combination of 3 NE RTOs has no net benefit	Modest benefits in core RTO region	Benefits uncertain, negative in some sub-regions	—	Energy benefits seem to exceed cost impacts
Release date	February 2002	January 2002	March 2002	November 2002	Sept/Oct 2003	November 2004

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Appendix 2-2: References for Other Cost Benefit Studies

Robert Michaels, "Vertical Integration and the Restructuring of the U.S. Electricity Industry", (Sept. 2004). http://ssrn.com/abstract=595565

Dr. Ronald J. Sutherland, "Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region," Version 1.1 (October 2003) Center for the Advancement of Energy Markets, http://www.caem.org [The CAEM PJM Study]

Mathew J. Morey, Laurence D. Kirsch, Steven Braithwait, B. Kelly Eakin, "Erecting Sandcastles From Numbers: The CAEM Study of Restructuring Electricity Markets or a Critique of 'Estimating The Benefits Of Restructuring Electricity Markets: An Application To The PJM Region,'" (December 3, 2003) Prepared for National Rural Electric Cooperative Association. Prepared by Laurits R. Christensen Associates, Inc., Madison, WI.

Charles River Associates, "The Benefits and Costs Of Regional Transmission Organizations and Standard Market Design in the Southeast," (November 6, 2002). Prepared for The Southeastern Association of Regulatory Utility Commissioners. [CRA SEARUC Study]

Steve Henderson, "RTO Cost Benefit Analysis" (May 2003). Presentation to Harvard Electricity Policy Group, Charles River Associates.

ICF Consulting, "Economic Assessment of RTO Policy," (February 26, 2002). Prepared for the Federal Energy Regulatory Commission. [ICF FERC Study]

Tabors Caramanis & Associates, "RTO West Benefit/Cost Study," (March 11, 2002). Final Report Presented to RTO West Filing Utilities. http://www.rtowest.com/Stage2BenCstMain.htm [TCA RTO West Study]

PJM, "PJM Cost/Benefit Analysis for Northeast RTO," (January 2002) [PJM NERTO Study]

Tabors Caramanis & Associates and KEMA Consulting, "Electric Reliability Council of Texas Market Restructuring Cost-Benefit Analysis," (November 30, 2004). http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=83&b= [TCA ERCOT Study]

Appendix 3-1: SPP MAPS Inputs

This appendix summarizes MAPS inputs and data sources for the SPP Cost Benefit study. Data sources include specific data from CBTF participants and from SPP and a database compiled from public sources by Charles River Associates (CRA) and Tabors Caramanis & Associates (TCA, now part of CRA). Public-domain data sources include FERC Forms 1, 714, and 715, Form EIA-411, the NERC ES&D and GADS databases, data from the US EPA, various trade press announcements, and planning data from NERC regions, control areas, and ISOs. In addition, CRA purchased transmission contingency constraint data for use outside of the SPP system from General Electric based on GE's in-depth PSS/E transmission system studies. CRA performed extensive in-house analysis to ensure data integrity and validity and to ensure consistency of the system representation with market developments.

Data Item **Page**

1. Load Inputs

Description. MAPS requires an hourly load shape and a forecast of annual peak load and total energy for each load-serving entity or zone. SPP provided CRA with EIA-411 load forecast data for each company within the study region for the study years 2005 through 2013. For 2014, CRA applied linear extrapolation to estimate the peak load and annual energy by company.

MAPS uses a historical hourly load shape for each load area to distribute energy over the course of each forecast year. SPP also provided historical hourly loads for each load area for the base year 2003. However, 2003 load shapes were not readily available for regions outside of SPP, and CRA believed that the use of inconsistent historical load shapes for different regions would lead to unrealistic patterns of interregional power flows. It was thus decided, in consultation with the CBTF, that CRA would apply 2002 load shapes (available from public sources) for all areas in SPP and outside to ensure inter-regional load consistency. MAPS uses hourly load shapes, combined with forecasts for peak load and annual energy for each company, to develop a detailed load forecast by company for each forecast year.

Data Sources. SPP provided EIA-411 data for peak load and annual energy by company, as well as hourly load shapes from FERC 714 filings by company.

2. Thermal Unit Characteristics

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

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

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. For this study, each member company updated and/or validated CRA's list of units and unit characteristics for their own generating assets.

If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used,**Error! Reference source not found.** and Table 2 documents these generic assumptions.[5] As was the case throughout the MAPS analysis, all prices are in real 2003 dollars.

Data Sources. The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, primary and secondary fuel type, and capacity data for existing units. For units within SPP, SPP member

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

companies supplemented and/or updated these data as necessary. Heat rate data were drawn from prior ES&D databases where available. For newer plants, heat rates were based on industry averages for the technology of each unit. The NERC Generation Availability Data System (GADS) database published in October 2003 (data through 2001) was the source for forced and planned outage rates, based on plant type, size, and age.

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

Table 1. Characteristics for Generic Thermal Units

Unit Type & Size	FOM ($/kW-yr)	VOM ($/MWh)	Minimum Downtime (hrs)	Minimum Uptime (hrs)	Heat Rate Shape
Combined Cycle	18.00	2.00	6	6	2 blocks, each 50%@FLHR
Combustion Turbine <100 MW	7.00	7.00	1	1	One block
Combustion Turbine >100 MW	7.00	3.50	1	1	One block
Steam Turbine [coal] <100 MW	38.00	2.00	6	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <200 MW	35.00	2.00	8	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] >200 MW	35.00	1.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [gas] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%

CRA models recently constructed CCGT units at a heat rate of 7100 Btu/kWh. For future CCGT units, CRA generically assumes a lower heat rate of 6900 Btu/kWh. CRA recognizes that such a heat rate for CCGT may not be achievable if the unit operates in a cycling mode with minimum up and down time limited to 6 hours as shown in Table 1. Thus, it is possible that the efficiency of future CCGT generating units might be overstated. However, this will make nearly no impact on the results of this study, because as explained below, no newly constructed CCGT units were modeled within the SPP region.

Table 2. Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start Capability (% of Capacity)	Spinning Reserves (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability (% of Year)	Startup (MMBtu /MW)
Combined Cycle	0.00	30.00	1.50	6.82	8.32	5.00
Combustion Turbine <100 MW	100.00	90.00	4.34	5.21	9.55	0.00
Combustion Turbine >100 MW	100.00	50.00	2.53	7.50	10.03	0.00
Steam Turbine [coal] <100 MW	0.00	10.00	2.96	9.48	12.44	
Steam Turbine [coal] <200 MW	0.00	10.00	3.46	8.66	12.12	20.00
Steam Turbine [coal] >200 MW	0.00	10.00	4.51	9.79	14.30	
Steam Turbine [gas] <100 MW	0.00	10.00	3.09	7.27	10.36	
Steam Turbine [gas] <200 MW	0.00	10.00	3.69	10.50	14.19	10.00
Steam Turbine [gas] >200 MW	0.00	10.00	3.38	12.46	15.84	
Steam Turbine [oil] <100 MW	0.00	10.00	2.14	7.91	10.05	
Steam Turbine [oil] <200 MW	0.00	10.00	4.64	10.95	15.59	
Steam Turbine [oil] >200 MW	0.00	10.00	4.01	12.04	16.05	10.00

3. Nuclear Units

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

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

4. Hydro Units

Description. MAPS has special provisions for modeling hydro units. For conventional or pondage units, CRA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. CRA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. CRA assumes that the maximum capacity for each hydro unit is flat throughout the year, that the minimum capacity is zero (i.e., that there are no stream-flow or other constraints that force a plant to generate), and that the monthly capacity factor is 17%.

For hydro units in the SPP region, CRA developed hydropower schedules based on consultation with and/or data provided by hydro plant owners.

Data Sources. The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database for 2003.

5. Wind Resources

Description. Individual wind resources were modeled either as zero-cost dispatchable energy resources with high (70%) outage rates or as hourly modifiers based on historical production data.

6. Capacity Additions and Retirements

Description. New entry is based on existing projects in development and on projects with signed interconnection agreements. These units are listed in Table 3. For study years 2010 and 2014, CRA had proposed to also add capacity based on economic and/or reliability criteria. However, due to a surplus of capacity in SPP no capacity balance units were required in the region during the study period.

Economic new capacity was added outside of the SPP region to balance regional markets in future years. New capacity was assumed to be based on combined-cycle gas turbines (CCGT) or simple-cycle gas turbines (SCGT), depending on market requirements and the relative economics of these options.

Discussions with the CBTF indicated that no units would be retired in SPP during the study period beyond those listed in Table 4, for which retirements have already been announced.

Table 3 New entry in SPP

Unit Name	State	Area	Type	Installation	Capacity (MW)	Heat Rate
Iatan 2	MO	KACP	STc	1/1/2010	800	9000

Table 4 Retirements in SPP

Unit Name	State	Type	Retirement	Capacity (MW)	Heat Rate
Teche 1	LA	STc	1/1/2008	23	13672
Teche 2	LA	STg	1/1/2008	48	12125
Teche 3	LA	Stgo	1/1/2008	359	10554
Rodemacher	LA	Stgo	1/1/2011	440	10316

Table 5 shows the resulting capacity balance for SPP.

Table 5 SPP Capacity Balance (MW)

Category	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Internal Demand	38,715	39,176	39,976	40,802	41,513	42,083	42,775	43,405	44,016	44,751
Interruptible Demand	1,010	1,014	1,021	1,026	1,030	1,033	1,039	1,044	1,052	1,056
Net Internal Demand	37,705	38,162	38,955	39,776	40,483	41,050	41,736	42,361	42,964	43,695
Required Reserve Margin (%)	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Load + Reserve	42,833	43,352	44,253	45,186	45,989	46,633	47,412	48,122	48,807	49,637
Purchases	2,331	2,377	2,176	2,034	2,044	2,042	2,051	1,947	1,947	1,947
Sales	1,045	982	724	729	734	610	557	511	511	511
New Entry	30	-	-	-	800	-	-	-	-	-
Retirement	-	-	430	-	-	440	-	-	-	-
Installed Capacity	52,059	52,089	52,089	51,659	51,659	52,459	52,019	52,019	52,019	52,019
Balance	10,512	10,132	9,288	7,778	6,980	7,258	6,101	5,333	4,648	3,818

7. Fuel Price Forecasts

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

Dual-fuel generators are simulated as follows:

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

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

Coal prices are drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States.

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

Specific oil and gas price forecasts used in this study are provided in Appendix 3-2.

8. Transmission System Representation

Description. The MAPS analysis is based on load-flow cases that include the entire eastern interconnect transmission system—transformers, lines, phase shifters, and buses—based on SPP's Market Development Working Group (MDWG) load flow cases for 2005 (used in the year-2006 analysis) and 2010 (used in the 2010 and 2014 analyses.) Potentially binding lines, interfaces, and contingency constraints are monitored. Within the SPP system, constraints and flow limits were represented as provided by SPP. Outside of SPP, constraints were drawn from the CRA database, which is derived and maintained from public data sources. Flow limits were based either on the thermal ratings of lines as provided in the load flow case (normal limit for interfaces, emergency limits for line-loss contingencies) or on regional reliability studies.

Data Sources. Load flow cases from the MDWG process were provided by SPP. SPP flowgate constraints were applied for the SPP Region. Outside of SPP, an updated set of potentially binding contingencies was prepared under contract to CRA by General Electric, based on GE's exhaustive contingency analysis, and was updated and validated by CRA.

9. Environmental Regulations

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

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. MAPS allocates the cost of the SO_2 trading permits to energy throughout the year. NO_x emissions permit prices are based on market trading data published by Cantor Fitzgerald.

Emission quantities are do not account for any projected future environmental controls required under the current Clean Air Interstate Rules, Clean Air Mercury Regulations, nor were any additional environmental controls included for pending regulation and/or legislation.

Data Sources. The EPA's Clean Air Markets database (2002) provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. NO_x permit prices are obtained from a Cantor Fitzgerald on-line resource.

10. External Region Supply

Description. The modeling footprint includes SPP, SERC, FRCC, MISO, Western PJM (Allegheny, Duquesne, AEP, ComEd), Ontario, and those portions of ECAR and MAPP that are not in MISO nor in PJM West. CRA did not explicitly model regions external to this footprint, such as ERCOT, the WECC, and the northeast power pools such as Eastern MAAC, NYISO, and ISO NE. Economic transactions with these outlying pools were generally represented as price-sensitive supply and demand curves to reflect historical patterns. The power flows between SPP and the WECC were represented as an hourly flow schedule, as to agreed with the CBTF following its review of interregional flows from the first set of model runs. The switchable units within SPP's footprint (Kiowa and Gateway, switchable to ERCOT) were not considered to be SPP capacity for purposes of the wholesale market study. The Oklaunion unit was reflected as a jointly owned unit.

11. Dispatchable Demand (Interruptible Load)

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

Data Sources. Data were drawn from the EIA-411 report data, as provided by SPP.

12. Market Model Assumptions

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

- *Operating Reserves Requirement (spinning and standby).* Operating reserves are based on requirements instituted by SPP and are based on the sum of the largest single contingency and one-half of the second largest contingency in the system. This requirement is distributed through the system on a load-share basis to form individual company reserve requirements. The spinning reserves market affects the energy prices because when capacity is reserved for spin it is not available for electricity production to serve load. Energy prices are higher when reserves markets are modeled. Outside of SPP, reserve requirements were implemented on a pool-wide basis according to pool-specific operating requirements.

- *Transmission Losses.* Transmission losses are modeled at average rates.

Wheeling rates. Within SPP, no wheeling rates between control areas are assumed for the Base and EIS cases. Wheeling rates between control areas for the Stand-Alone case are based on company-specific firm transmission rates as detailed in the individual transmission tariffs. Wheeling rates do apply between Cleco and other SPP companies as well as between SPP and SERC, SPP and MISO, and between MISO and SERC. Region-to-region wheeling rates are detailed in Table 6; company-specific wheel-out rates for SPP companies (Stand-Alone case) are shown in Table 7.

Table 6 Wheeling rate overview

		TO					
	Region	Scenario	SPP	MISO	SERC	Aquila	Cleco
FROM	SPP	IE & BC	-	Tariff	Tariff	Tariff	Tariff
		SA	Tariff	Tariff	Tariff	Tariff	Tariff
	MISO	IE & BC	$2	-	$2	-	NA
		SA	$2	-	$2	-	NA
	SERC	IE & BC	$2	$2	-	$2	-
		SA	$2	$2	-	$2	-
	Aquila	IE & BC	Tariff	-	Tariff	-	NA
		SA	Tariff	-	Tariff	-	NA
	Cleco	IE & BC	$4	NA	$4	NA	-
		SA	$4	NA	$4	NA	-

Table 7 Wheel-out rates for SPP and Aquila companies

Company	Commitment	Dispatch
Public Service Company of Oklahoma and Southwestern Electric Power Company	$2	$2
City Utilities of Springfield, Missouri	$2	$3
Empire	$2	$2
Grand River Dam Authority	$3	$7
Kansas City Power and Light Company	$2	$2
Mid-West Energy	$4	$6
Oklahoma Gas & Electric Company	$2	$2
Southwestern Power Administration	$1	$2
Southwestern Public Service	$2	$3
Western Resources, Inc	$2	$2
Western Farmers Electric Cooperative	$3	$3
Aquila Companies		
Missouri Public Service	$1	$1
West Plaines	$2	$3

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Appendix 3-2: Fuel Price Assumptions

MEMORANDUM

TO: SPP CBTF

FROM: Alex Rudkevich, Charles River Associates

SUBJECT: Fuel Price Forecast

DATE: August 30, 2004

The purpose of this memo is to document the Base Case scenario for the electricity generation fuels price forecast. The forecast includes prices for natural gas, distillate (#2), residual (#6) fuel oil and coal. Note that all prices are in real 2003 dollars. Also all figures are detailed in the Excel workbook accompanying this memo along with the underlying numerical data.

Coal Price Forecast

Long-term forecast of coal prices by power plant has been provided by CRA which purchased this forecast from Platt's RDI. CRA will rely on this forecast in its entirety.

Fuel Oil and Natural Gas Price Forecast

CRA develops an in-house forecast of natural gas and fuel oil prices discussed in the balance of this memorandum.

Geographical Markets

The regionalization of fuel markets follows natural gas trading points rather than markets for fuel oil. The forecast covers the following areas in the US and Canada.

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Table 1 Forecast Regions

Midwestern Regions	**South Atlantic South**	**IA/MO/NE**	**Appalachia**	**South Atlantic East**	**Midcon**	**Canada**
Illinois	Alabama	Iowa	Kentucky	Georgia	Kansas	East Ontario
Indiana	Arkansas	Missouri	Ohio	North Carolina	Oklahoma	West Ontario
Michigan	Louisiana	Nebraska	Pennsylvania	South Carolina		
Minnesota	Mississippi		West Virginia	Virginia		
Wisconsin	Tennessee			South Maryland		
				Delaware		
Florida	**Texas non-ERCOT**			DC		
Florida	East TX non ERCOT					
	North TX non ERCOT					

Forecasts Drivers

The principal drivers of CRA fuel forecasts are projected prices for crude oil (Light Sweet Crude) and for natural gas at Henry Hub and selected regional hubs traded forward on NYMEX. All other forecasts are derived from these driving projections using forecast and/or historical basis differentials as explained later in this memo.

Generally CRA develops the base case forecast of crude oil prices as a composition of NYMEX futures prices in the short term and EIA's forecast in the long-term as published in EIA's *Annual Energy Outlook 2004*.

Similarly, CRA develops the forecast for the spot price of natural gas at Henry Hub as a composition of futures prices in the near-term and a long-term forecast from EIA's *Annual Energy Outlook 2004*.[6] In addition, CRA relies on forward basis differentials for the following natural gas hubs traded on NYMEX Clearport (NYMEX hubs):

- ANR OK
- Chicago
- Columbia Gulf Onshore
- Dominion
- MichCon
- NGPL Midcon
- NGPL TexOk
- NGPL Louisiana

6 *AEO-2004* does not forecast Henry Hub prices but instead predicts prices at the wellhead. A historical multiplication factor of 1.129 is used to derive the Henry Hub price forecast.

- Permian
- Northern Natural Demarcation
- Panhandle
- TCO (Columbia Gas)
- TETCO East LA
- TETCO Zone M3
- Transco Zone 3
- Transco Zone 6
- Ventura

Basis differentials to these hubs from the Henry Hub are traded for a relatively short period, typically between 12 and 24 months. For those periods, CRA derives summer and winter basis differentials to those hubs using NYMEX data. Beyond those periods, CRA scales these basis differentials in proportion to the Henry Hub price forecast. Forecast prices at each hub are derived as a sum of the Henry Hub price forecast and a hub-specific basis differential.

Natural Gas Pricing Points

For the purpose of modeling electricity markets, CRA recognizes multiple pricing points within each region. All pricing points are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with NYMEX hubs, hence the forecast for these pricing points are given by the forecast for NYMEX hubs described above. CRA derives forecasts for pricing points that do not coincide with NYMEX hub using regression models calibrated with historical data. Table 2 below lists all relevant pricing points and maps points to NYMEX hubs used as drivers for those points in the CRA regression model.

Table 2 Pricing Points

Natural Gas Regions	Pricing Points	NYMEX Hubs used for regression
E. Ontario	Niagara	MichCon Transco Z6
Midwest	Chicago	Chicago
	MichCon	MichCon
S. Atlantic South	Henry Hub	Henry Hub
IA/MO/NE	Ventura	Ventura
W. Ontario	Dawn	Dominion MichCon
Appalachia	Columbia Gas (TCO)	Columbia Gas (TCO)
	Dominion	Dominion
	CNGL	Dominion
Midcon	NGPL Midcon	NGPL Midcon
S. Atlantic East	FGTMB	Tetco East LA
	KochM	Transco Z3
	Tetco M-1	Tetco East LA
	TRS85	Tetco East LA
	Transco Z6 (Non-NY)	Transco Z6 Columbia Gas (TCO)
	TETCO M-3	TETCO M-3
Texas Non-ERCOT East	Carthage	Henry Hub
Texas Non-ERCOT North	NGPL Midcon	NGPL Midcon
	NGPL Permian	Permian
Florida	Florida Gas Transm	Henry Hub

Basis Forecasts

As stated earlier, the key underlying forecasts are projected prices for crude oil (WTI) and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected and/or historical basis differentials.

Figure 1 below presents the CRA proposed base case forecast of crude oil prices in comparison with:

- historical prices,
- NYMEX futures prices for the light sweet crude oil (as of August 26, 2004), and
- a long term forecast for crude oil prices from EIA's *Annual Energy Outlook-2004*.

As one can see, CRA's proposed forecast is a composition of futures prices in the short term (2005-2009) and EIA's forecast in the long-run (2013-2020). Years 2010 through 2012 are interpolated.

Similarly, Figure 2 presents the CRA proposed forecast for the spot price of natural gas at Henry Hub. The forecast is shown in comparison with average NYMEX futures prices (as of August 26, 2004[7]) and a long-term forecast per EIA's Annual Energy Outlook-2004.[8] CRA's proposed forecast is a composition of futures prices in the near-term (2005-2009), and EIA's long-term forecast in the long-run (2012-2020). Years 2010 and 2011 are interpolated.

Generation Fuel Prices

Generation fuel prices are derived from the basis forecasts. Figures 3 through 8 present comparisons of monthly generation fuel prices for the Midwestern region, South Atlantic South, South Atlantic East, Appalachia, Midcon and IA/MO/NE for the period 2005-2015. Figure 9 provides a comparison of regional natural gas prices. The methodologies associated with these forecasts are explained below.

Fuel Oil Prices – Methodology

To derive fuel oil prices for electric generation, an in-house linear regression model, which links crude oil prices with #6 and #2 fuel oil in the Northeastern US (New York Harbor), was used. For petroleum prices in other regions, state-specific basis differentials using EIA Form 423 data for 1997-2000 and historical spot prices for #2 and #6 fuel oil at New York Harbor were used. CRA assumes a modest seasonal pattern for #2 fuel oil prices, the same in all regions. Prices for #6 fuel oil are assumed flat. Table 3 shows the fuel oil basis differentials.

7 The NYMEX Clearport futures data available for the NYMEX hubs are usually one day old while the NYMEX futures data are available in real time.

8 *AEO-2003* does not forecast Henry Hub prices, instead it predicts prices at the wellhead. To come up with the Henry Hub price forecast a historical multiplication factor of 1.14 is applied.

Table 3 Basis Differentials from NY Harbor to the Burner-tip by State

State	FO2 Basis ($/MMBtu)	FO6 Basis ($/MMBtu)
IL	0.62	0.53
IN	0.52	
MI	0.39	0.38
MN	0.82	
WI	0.56	
AL	-0.10	
AR	0.42	
LA	0.37	0.05
MS	0.18	-0.31
TN	0.28	
FL	0.49	0.01
IA	0.39	
MO	0.38	-0.35
NE	0.69	
OH	0.38	
GA	0.48	0.18
SC	0.47	
NC	0.26	
DE	0.34	0.11
DC	0.38	
VA	0.33	-0.07
MD	0.23	0.10
PA	0.31	0.11
KY	0.85	
WV	0.77	
OK	0.21	
KS	0.54	-0.29
TX	0.37	0.81

Natural Gas Prices – Methodology

1. The burner-tip price for natural gas is a sum of two components – regional price and local delivery price.
2. Local delivery price is differentiated by state based on the American Gas Association's statistics. This price is applied **to existing plants only** (see Table 4 below for details).
3. For new gas-fired plants, the local component is set at $0.07/MMbtu to reflect pipeline lateral charges. (This is CRA's "best-guess" estimate.)
4. Forecast regional gas prices are derived from the NYMEX Hubs forecast using CRA in-house regression models calibrated on historical regional prices vs. prices at Henry Hub. The modeling structure by region is outline in Table 2.
5. Seasonal patterns are developed in the following manner:

   For Henry Hub, CRA uses seasonal pattern revealed in futures prices. Revealed pattern for 2009 is assumed for all years from 2010 onward.

Regional seasonal patterns appear automatically by applying the regression model to the monthly Henry Hub forecast.

Table 4. LDC Charges Applied for Older Gas-fired Plants by State

State	LDC Charge ($/MMBtu)
IL	0.09
IN	0.36
MI	0.59
MN	0.12
WI	0.49
AL	0.37
AR	0.23
LA	0.09
MS	0.19
TN	0.37
FL	0.23
GA	0.32
SC	0.96
NC	0.47
VA	0.52
MD	0
DE	0
DC	0
IA	0.31
MO	0.01
NE	0.13
OH	0.53
PA	0.11
KY	0.69
WV	0.26
OK	0.24
KS	0.31
TX	0.03

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Figure 1. Crude Oil Prices: History and Projections (2003$/BBL)

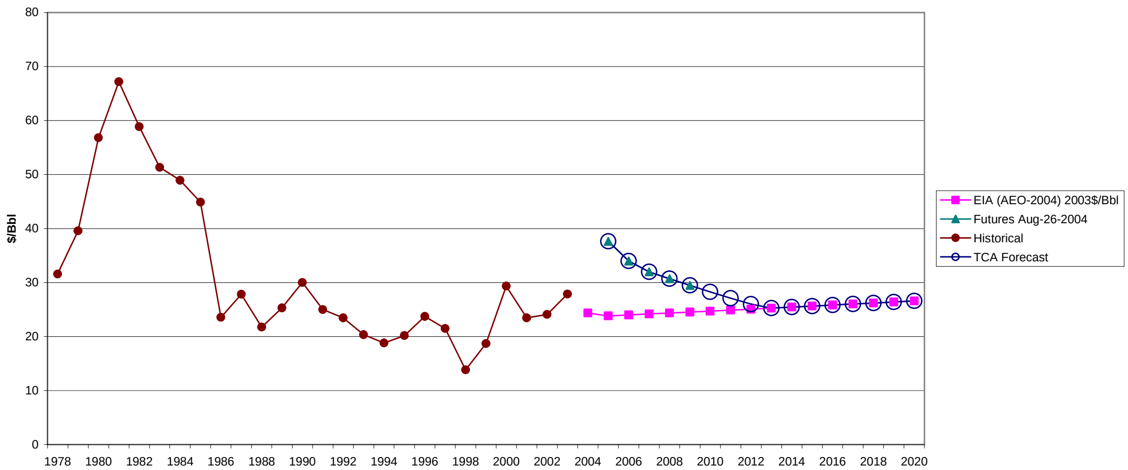

Figure 2. Natural Gas Spot Prices at Henry Hub: History and Projections (2003$/MMBtu)

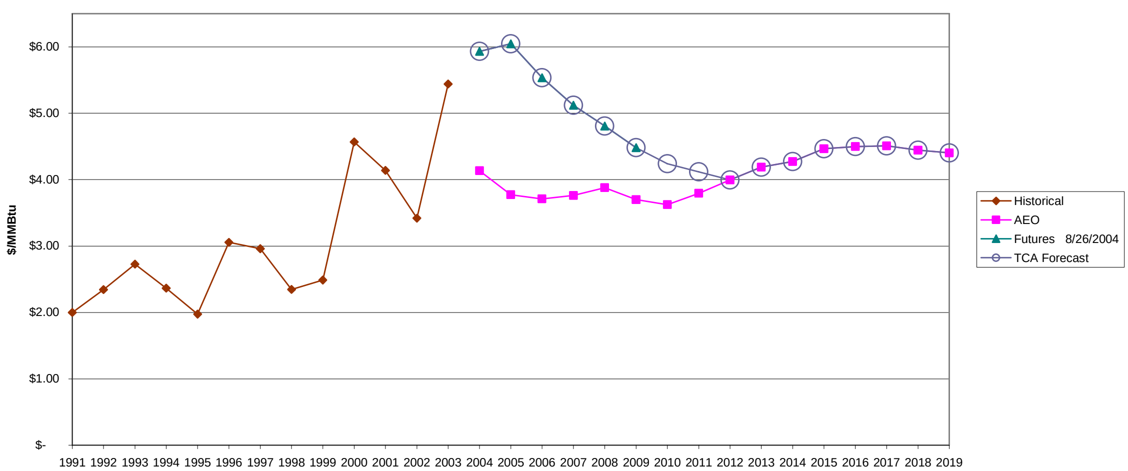

Figure 3. Fuel Price Forecast: Midwest Region (MI, IL, WI, IN, MN)

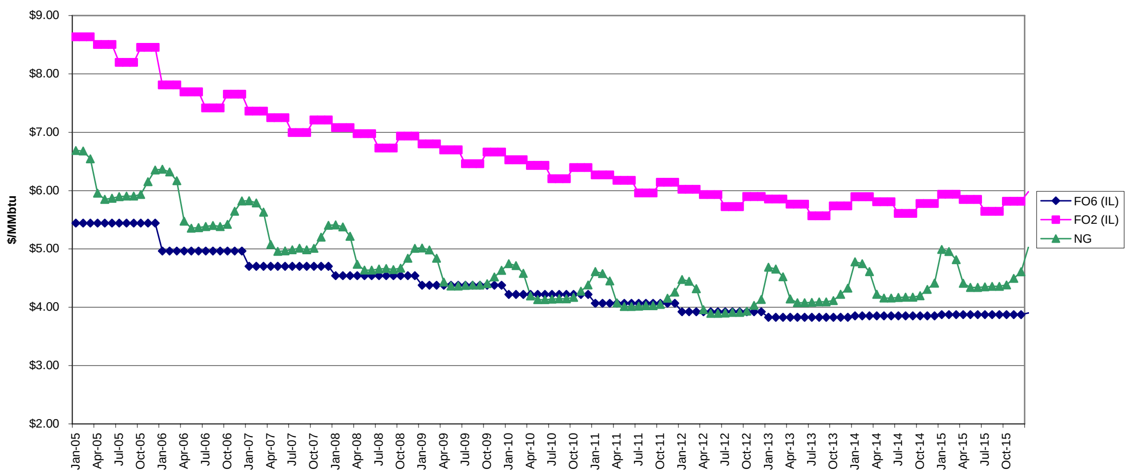

Figure 4. Fuel Price Forecast: South Atlantic - South (AL, AR, LA, MS, TN)

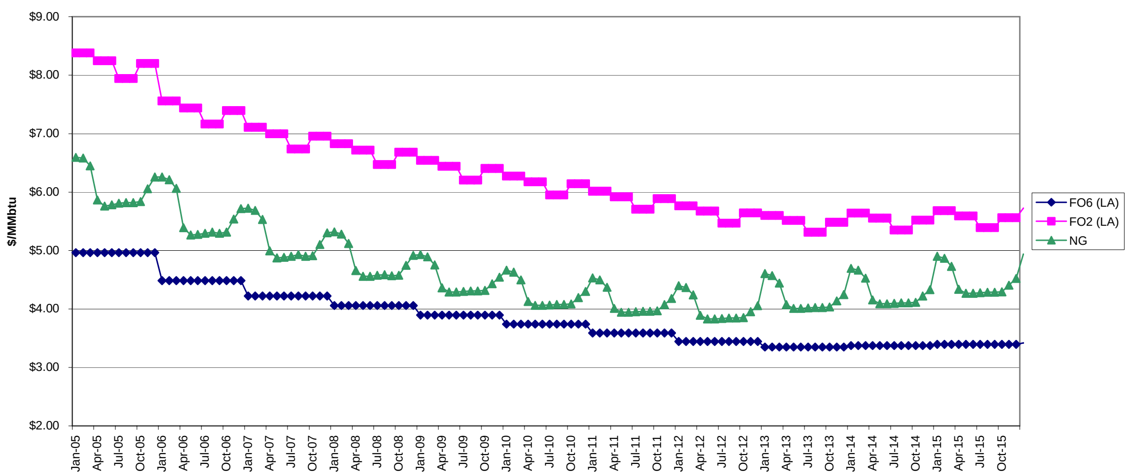

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Figure 5. Fuel Price Forecast: South Atlantic East

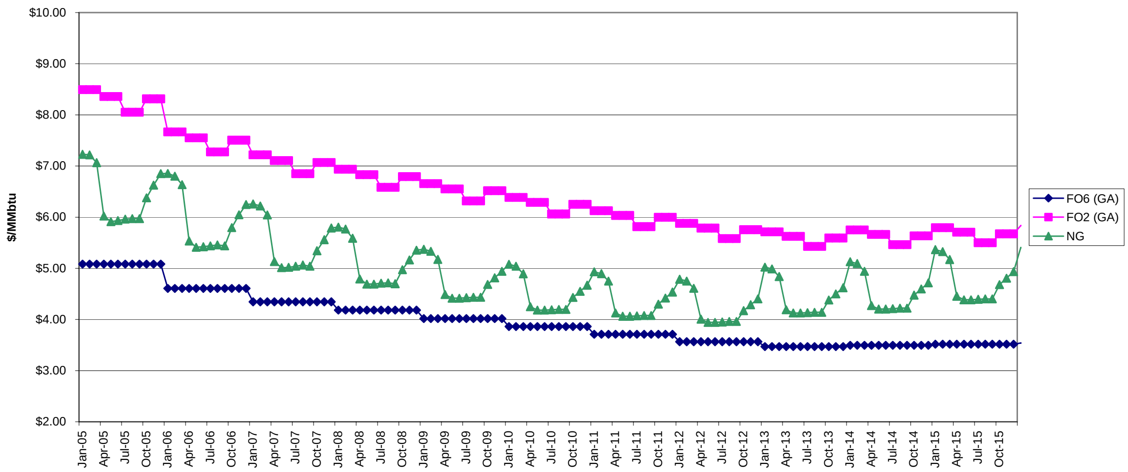

Figure 6. Fuel Price Forecast: Appalachia (W. PA, WV, OH, KY)

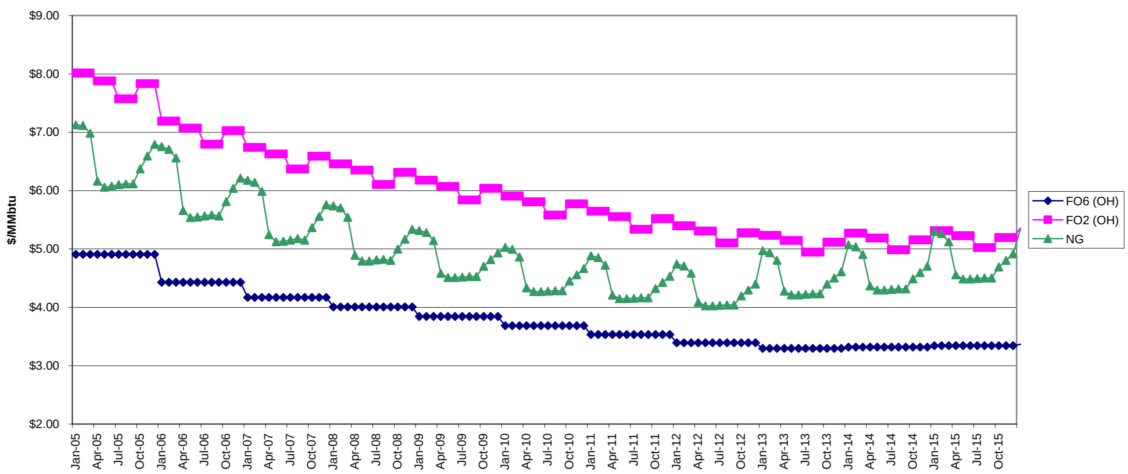

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Figure 7. Fuel Price Forecast: Midcon (OK, KS)

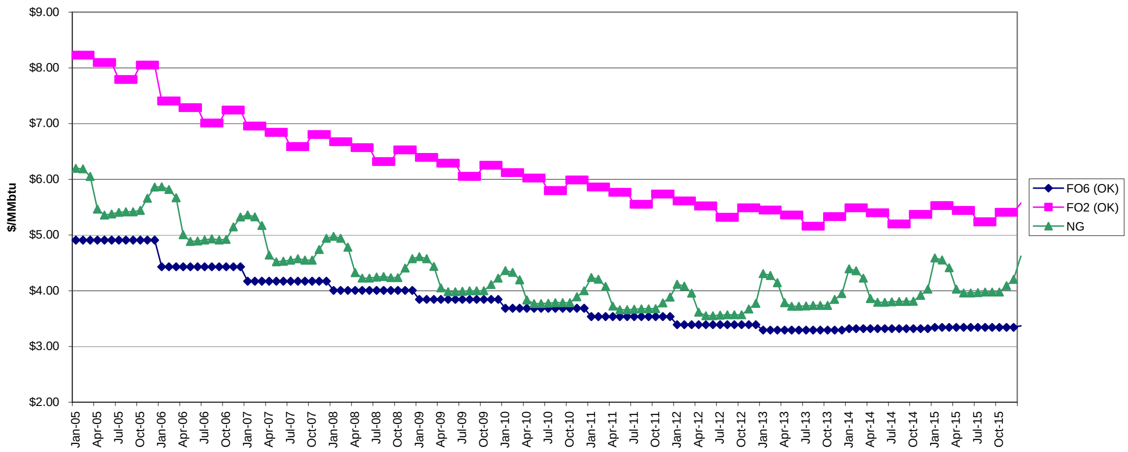


Figure 8. Fuel Price Forecast: Iowa-Missouri-Nebraska

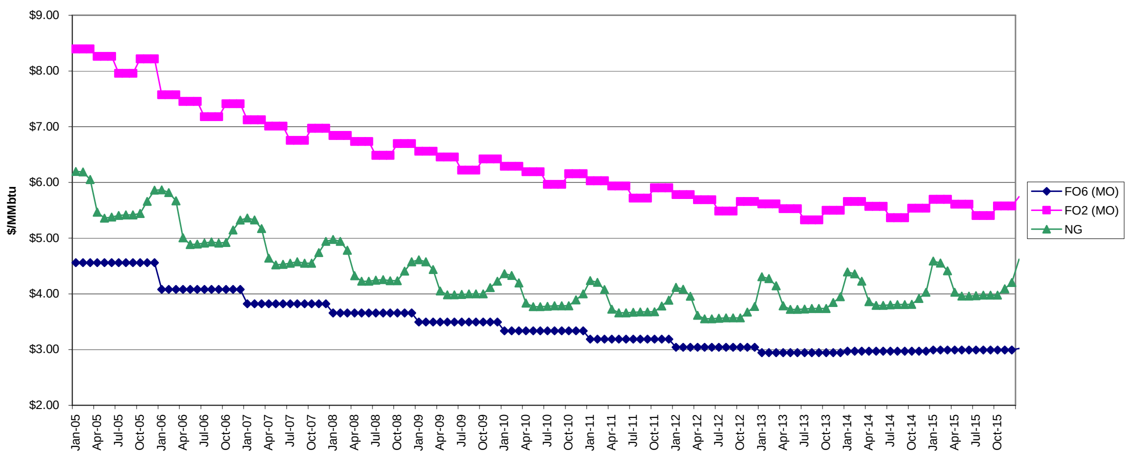
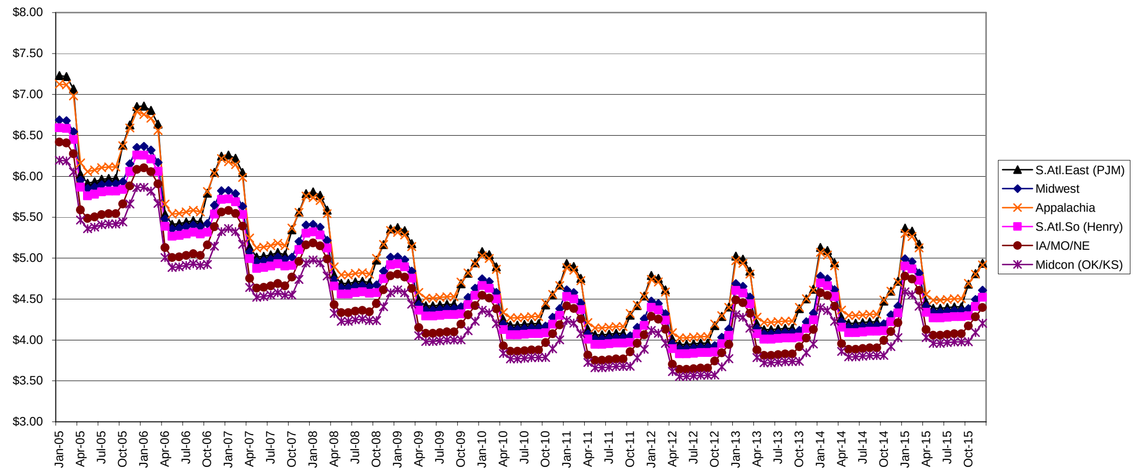


Figure 9. Comparison of Regional Monthly Natural Gas Prices (2005-2015)



Appendix 3-3: Wheeling Rates

Wheeling rates are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, wheeling rates are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch. For the current analysis, the wheeling rates for commitment were based on the day-ahead firm transmission rates in the individual companies' tariffs, while the rate for dispatch was based on the real-time rates. As it is impossible to precisely replicate the transmission tariffs in MAPS, the resulting rates were vetted for reasonableness with the CBTF.

Table 3-3.1 gives an overview of the wheeling rates between SPP, MISO, SERC and the Aquila and Cleco control areas for the Base and EIS cases; Table 3-3.2 shows these rates for the Aquila case. Table 3-3.3 shows control area specific wheel-out rates for SPP areas. These rates are used as the inter-area wheeling rates in the Stand Alone case.

Table 3-3.1 Wheeling Rates (Dispatch) in Base and EIS Cases

	TO						
FROM	Region	Scenario	SPP	MISO	SERC	Aquila	Cleco
	SPP	EIS & BC	-	Tariff	Tariff	Tariff	Tariff
		SA	Tariff	Tariff	Tariff	Tariff	Tariff
	MISO	EIS & BC	$2	-	$2	-	NA
		SA	$2	-	$2	-	NA
	SERC	EIS & BC	$2	$2	-	$2	-
		SA	$2	$2	-	$2	-
	Aquila	EIS & BC	Tariff	-	Tariff	-	NA
		SA	Tariff	-	Tariff	-	NA
	Cleco	EIS & BC	$4	NA	$4	NA	-
		SA	$4	NA	$4	NA	-

Table 3-3.2 Wheeling Rates (Dispatch) in Aquila Base and EIS Cases

	TO						
FROM	Region	Scenario	SPP	MISO	SERC	Aquila	Cleco
	SPP	EIS & BC	-	Tariff	Tariff	-	Tariff
	MISO	EIS & BC	$2	-	$2	$2	NA
	SERC	EIS & BC	$2	$2	-	$2	-
	Aquila	EIS & BC	-	$2	$2	-	NA
	Cleco	EIS & BC	$4	NA	$4	NA	-

Table 3-3.3 Wheel-out rates for SPP and Aquila companies

Company	Commitment	Dispatch
Public Service Company of Oklahoma and Southwestern Electric Power Company	$2	$2
City Utilities of Springfield, Missouri	$2	$3
Empire	$2	$2
Grand River Dam Authority	$3	$7
Kansas City Power and Light Company	$2	$2
Mid-West Energy	$4	$6
Oklahoma Gas & Electric Company	$2	$2
Southwestern Power Administration	$1	$2
Southwestern Public Service	$2	$3
Western Resources, Inc	$2	$2
Western Farmers Electric Cooperative	$3	$3
Aquila Companies		
Missouri Public Service	$1	$1
West Plaines	$2	$3

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Appendices 4-1, 4-2, 4-3, and 4-4

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Appendix 4-1 Benefits (Costs) by Company for the Stand-Alone Case

Table 1

Benefits/(Costs) of Moving from Base Case to Stand Alone Case

(2006-2015, thousands of January 2006 present value dollars; positive numbers are benefits)

	Source:	*Table 3*	*Table 6*	*Table 7*	*Table 8*	*Table 9*	*Table 10*	*Table 11*	
		Trade Benefits	**Wheeling Charges**	**Wheeling Revenues**	**Costs to Provide Functions**	**FERC Charges**	**Transm. Constr. Costs**	**With-drawal Oblig.**	**Total**
TOs Under SPP Tariff									
AEP	IOU	(8,259)	(139,645)	136,610	69	6,260	(5,502)	(12,377)	(22,845)
Empire	IOU	(3,565)	(40,370)	20,573	(707)	1,106	(829)	(1,803)	(25,595)
KCPL	IOU	(4,582)	(5,057)	73,733	(10,815)	3,166	(823)	(4,731)	50,891
OGE	IOU	(1,025)	(87,249)	76,844	(3,536)	5,383	(811)	(8,187)	(18,580)
SPS	IOU	(1,114)	(26,670)	76,126	(3,252)	5,239	1,400	(7,229)	44,500
Westar Energy	IOU	(471)	(67,678)	67,847	(13,614)	1,874	1,345	(6,183)	(16,879)
Midwest Energy	Coop	(10)	(2,818)	6,767	(7,822)	295	327	(670)	(3,931)
Western Farmers	Coop	(962)	(70,356)	17,903	1,071	1,684	1,543	(2,050)	(51,168)
SWPA	Fed	(26)	(33,261)	12,409	(9)	370	2,159	(1,297)	(19,655)
GRDA	State	(179)	(26,182)	20,201	(4,814)	1,087	603	(1,485)	(10,769)
Springfield, MO	Muni	(672)	(511)	6,574	(2,543)	853	1,080	(1,234)	3,547
Sub-Total		(20,864)	(499,797)	515,585	(45,970)	27,315	494	(47,246)	(70,484)
Other Typical Assessment Paying Members									
AECC	Coop	(3,133)	(10,344)	10,119	5	934	(405)	(1,298)	(4,121)
Kansas City, KS	Muni	(1,975)	(651)	9,487	(1,479)	652	-	(1,084)	4,950
OMPA	Muni	(666)	(8,378)	6,549	(160)	781	(89)	(1,022)	(2,985)
Independence, MO	Muni	(219)	(953)	(83)	(455)	344	-	(688)	(2,054)
Sub-Total		(5,993)	(20,326)	26,073	(2,089)	2,711	(494)	(4,092)	(4,210)
Total of Above		(26,857)	(520,124)	541,657	(48,060)	30,027	-	(51,338)	(74,694)
Others									
Cleco Power		(1,471)	(107)	(659)					(2,238)
City of Lafayette, LA		(68)	(21)	(132)					(221)
LEPA		(2)	(12)	(75)					(90)
Aquila - MPS/SJ		(464)	(5,694)	(494)					(6,653)
Sunflower		(144)	595	-					452
Aquila - West Plains		(561)	(6,427)	6,443					(545)
Merchants in SPP		(8,645)	-	-					(8,645)
Rest of Eastern Interconnect		(15,585)	(11,808)	(3,141)					(30,534)
Grand Total		(53,797)	(543,599)	543,599					

Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 2

State Allocation for Multi-State Utilities

Benefits/(Costs) of Moving from Base Case to Stand Alone Case

(2006-2015, thousands of January 2006 present value dollars; positive numbers are benefits)

State Allocation for Multi-State Investor-Owned Utilities

		Retail							
	Wholesale	Arkansas	Louisiana	Kansas	Missouri	New Mexico	Oklahoma	Texas	Total
AEP	12.7%	10.8%	14.1%				44.6%	17.8%	100.0%
Empire	6.4%	3.0%		5.2%	82.7%		2.7%		100.0%
KCPL - Trade	1.0%			41.4%	57.7%				100.0%
KCPL - Other	13.5%			38.8%	47.7%				100.0%
OGE	9.4%	10.5%					80.1%		100.0%
SPS	40.1%			0.1%		13.3%	1.2%	45.3%	100.0%
Westar Energy	12.7%			87.3%					100.0%

Allocations are based on net energy for load, except for KCPL - Other which is based on 4 summer months coincident peak and applies to all KCPL cost-benefit components other than Trade Benefits

In the calculation below, AEP trade benefits are subdivided between PSO and Swepco using the generation of each operating company before the allocation by state. PSO is in Oklahoma only, and Swepco is in Arkansas, Lousiana and Texas.

Benefits/(Costs) of Moving from Base Case to Stand-Alone Case (K$)

		Retail							
	Wholesale	Arkansas	Louisiana	Kansas	Missouri	New Mexico	Oklahoma	Texas	Total
AEP	(2,901)	(2,307)	(3,012)				(10,822)	(3,802)	(22,845)
Empire	(1,633)	(773)		(1,326)	(21,167)		(696)	-	(25,595)
KCPL	7,430			19,637	23,824				50,891
OGE	(1,743)	(1,958)					(14,879)		(18,580)
SPS	17,853			44		5,914	521	20,167	44,500
Westar Energy	(2,144)			(14,735)					(16,879)
Total	16,863	(5,038)	(3,012)	3,621	2,657	5,914	(25,877)	16,365	11,492

Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 3
Trade Benefits - Stand Alone Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	(8,259)	(2,267)	(1,860)	(1,433)	(985)	(516)	(667)	(823)	(987)	(1,158)	(1,185)
Empire	IOU	(3,565)	(1,077)	(866)	(644)	(413)	(170)	(235)	(304)	(376)	(451)	(461)
KCPL	IOU	(4,582)	(1,324)	(1,058)	(779)	(486)	(179)	(307)	(440)	(579)	(725)	(741)
OGE	IOU	(1,025)	(224)	(182)	(139)	(93)	(45)	(94)	(145)	(198)	(254)	(260)
SPS	IOU	(1,114)	(29)	(61)	(95)	(131)	(168)	(217)	(269)	(322)	(378)	(387)
Westar Energy	IOU	(471)	(148)	(116)	(82)	(47)	(10)	(24)	(39)	(55)	(71)	(73)
Midwest Energy	Coop	(10)	(4)	(3)	(2)	(1)	(0)	(0)	(1)	(1)	(1)	(1)
Western Farmers	Coop	(962)	(306)	(238)	(166)	(90)	(11)	(45)	(80)	(117)	(156)	(160)
SWPA	Fed	(26)	(5)	(5)	(4)	(3)	(2)	(3)	(4)	(4)	(5)	(5)
GRDA	State	(179)	(50)	(40)	(30)	(19)	(7)	(13)	(18)	(24)	(31)	(31)
Springfield, MO	Muni	(672)	(228)	(180)	(130)	(77)	(22)	(33)	(44)	(55)	(66)	(68)
Sub-Total		(20,864)	(5,662)	(4,608)	(3,503)	(2,345)	(1,131)	(1,638)	(2,167)	(2,719)	(3,296)	(3,372)
Other Typical Assessment Paying Members												
AECC	Coop	(3,133)	(976)	(780)	(575)	(359)	(134)	(191)	(252)	(315)	(380)	(389)
Kansas City, KS	Muni	(1,975)	(657)	(519)	(373)	(221)	(62)	(98)	(137)	(177)	(219)	(224)
OMPA	Muni	(666)	(204)	(162)	(118)	(72)	(23)	(40)	(57)	(75)	(94)	(96)
Independence, MO	Muni	(219)	(54)	(44)	(34)	(24)	(13)	(20)	(26)	(33)	(40)	(41)
Sub-Total		(5,993)	(1,891)	(1,505)	(1,100)	(676)	(232)	(349)	(472)	(600)	(733)	(750)
Total of Above		(26,857)	(7,553)	(6,113)	(4,603)	(3,021)	(1,363)	(1,987)	(2,638)	(3,319)	(4,029)	(4,122)
Others												
Cleco Power		(1,471)	(645)	(497)	(342)	(180)	(9)	(9)	(9)	(8)	(8)	(8)
City of Lafayette, LA		(68)	(26)	(20)	(14)	(7)	(1)	(2)	(3)	(5)	(6)	(6)
LEPA		(2)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)
Aquila - MPS/SJ		(464)	(108)	(90)	(71)	(52)	(31)	(44)	(58)	(73)	(88)	(90)
Sunflower		(144)	(30)	(26)	(23)	(18)	(14)	(17)	(19)	(22)	(24)	(25)
Aquila - West Plains		(561)	(206)	(161)	(113)	(64)	(12)	(19)	(28)	(36)	(45)	(46)
Merchants in SPP		(8,645)	1,473	1,355	1,230	1,100	962	(1,353)	(3,775)	(6,308)	(8,956)	(9,162)
Rest of Eastern Interconnect		(15,585)	(5,125)	(4,035)	(2,891)	(1,693)	(438)	(777)	(1,131)	(1,501)	(1,888)	(1,931)
Grand Total		(53,797)	(12,220)	(9,588)	(6,827)	(3,935)	(906)	(4,208)	(7,662)	(11,273)	(15,045)	(15,391)

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Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 4

Increase in Owned Generation Production Cost -- Moving from Base Case to StandAlone Case

(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	116,690	8,307	12,399	16,674	21,140	25,802	24,223	22,559	20,805	18,958	19,395
Empire	IOU	48,428	5,938	6,597	7,283	7,997	8,741	8,489	8,221	7,936	7,634	7,810
KCPL	IOU	(37,496)	(3,665)	(4,039)	(4,428)	(4,833)	(5,254)	(6,287)	(7,363)	(8,487)	(9,657)	(9,880)
OGE	IOU	(11,099)	440	(24)	(509)	(1,017)	(1,547)	(2,348)	(3,185)	(4,060)	(4,972)	(5,087)
SPS	IOU	39,436	1,355	3,241	5,213	7,273	9,426	8,927	8,401	7,846	7,261	7,428
Westar Energy	IOU	10,724	1,231	1,353	1,479	1,611	1,748	1,834	1,923	2,015	2,111	2,159
Midwest Energy	Coop	146	32	28	23	18	13	16	19	22	25	25
Western Farmers	Coop	7,313	2,175	1,395	577	(278)	(1,174)	(96)	1,032	2,212	3,445	3,525
SWPA	Fed	(2)	(0)	(0)	(0)	(1)	(1)	(1)	(0)	(0)	0	0
GRDA	State	(359)	(40)	(50)	(60)	(71)	(83)	(71)	(59)	(47)	(33)	(34)
Springfield, MO	Muni	(8,403)	(2,745)	(2,216)	(1,663)	(1,082)	(474)	(517)	(562)	(609)	(657)	(672)
Sub-Total		165,378	13,029	18,683	24,589	30,758	37,197	34,170	30,985	27,635	24,114	24,669
Other Typical Assessment Paying Members												
AECC	Coop	30,583	3,929	4,290	4,666	5,056	5,463	5,281	5,089	4,884	4,668	4,775
Kansas City, KS	Muni	(11,030)	(1,710)	(1,686)	(1,660)	(1,632)	(1,602)	(1,668)	(1,736)	(1,806)	(1,878)	(1,922)
OMPA	Muni	11,589	1,642	1,650	1,657	1,664	1,670	1,797	1,929	2,065	2,207	2,258
Independence, MO	Muni	3,840	481	516	553	591	630	645	661	677	693	709
Sub-Total		34,981	4,342	4,770	5,216	5,679	6,161	6,056	5,942	5,821	5,690	5,821
Total of Above		200,359	17,372	23,453	29,805	36,437	43,358	40,226	36,927	33,455	29,804	30,490
Others												
Cleco Power		(11,358)	(3,705)	(3,075)	(2,415)	(1,723)	(998)	(839)	(673)	(498)	(315)	(322)
City of Lafayette, LA		900	236	189	140	89	35	68	102	138	175	180
LEPA		(86)	(1)	(12)	(23)	(35)	(47)	(30)	(13)	6	26	26
Aquila - MPS/SJ		(9,371)	(1,571)	(1,623)	(1,676)	(1,731)	(1,788)	(1,544)	(1,289)	(1,020)	(739)	(756)
Sunflower		4,865	271	491	721	962	1,213	1,087	955	817	671	687
Aquila - West Plains		6,384	1,377	1,213	1,040	858	668	740	815	893	975	997
Merchants in SPP		(107,281)	(6,064)	(10,408)	(14,948)	(19,692)	(24,645)	(23,135)	(21,542)	(19,863)	(18,096)	(18,512)
Rest of Eastern Interconnect		(30,614)	4,306	(640)	(5,816)	(11,230)	(16,889)	(12,364)	(7,622)	(2,656)	2,543	2,602
Grand Total		53,797	12,220	9,588	6,827	3,935	906	4,208	7,662	11,273	15,045	15,391

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Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 5
Increase in Owned Generation -- Moving from Base Case to StandAlone Case
(Thousands of MWh)

		Total	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	5,243	337	425	513	600	688	634	579	525	470	470
Empire	IOU	1,946	160	177	193	210	226	215	205	194	183	183
KCPL	IOU	(2,479)	(197)	(208)	(218)	(229)	(239)	(253)	(267)	(281)	(294)	(294)
OGE	IOU	(683)	(33)	(40)	(46)	(53)	(60)	(70)	(81)	(92)	(103)	(103)
SPS	IOU	1,423	(4)	53	110	167	224	206	189	171	154	154
Westar Energy	IOU	209	22	20	18	15	13	17	21	25	29	29
Midwest Energy	Coop	3	1	0	0	0	0	0	0	0	0	0
Western Farmers	Coop	277	46	31	15	0	(15)	5	24	44	63	63
SWPA	Fed	(22)	(1)	(1)	(2)	(3)	(3)	(3)	(3)	(2)	(2)	(2)
GRDA	State	(99)	(7)	(8)	(8)	(9)	(9)	(10)	(11)	(12)	(13)	(13)
Springfield, MO	Muni	(299)	(34)	(33)	(32)	(31)	(30)	(29)	(28)	(28)	(27)	(27)
Sub-Total		5,519	289	416	542	669	796	712	628	545	461	461
Other Typical Assessment Paying Members												
AECC	Coop	1,616	145	153	162	170	178	172	166	160	155	155
Kansas City, KS	Muni	(884)	(98)	(94)	(90)	(86)	(82)	(84)	(85)	(87)	(89)	(89)
OMPA	Muni	334	30	31	31	31	31	33	35	36	38	38
Independence, MO	Muni	148	8	10	13	15	18	17	17	17	16	16
Sub-Total		1,214	86	100	115	130	145	139	132	126	120	120
Total of Above		6,733	375	516	658	799	941	851	761	671	581	581
Others												
Cleco Power		(302)	(96)	(75)	(54)	(33)	(13)	(10)	(8)	(6)	(3)	(3)
City of Lafayette, LA		21	4	3	2	1	1	1	2	2	3	3
LEPA		(1)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	0	0	0
Aquila - MPS/SJ		(330)	(16)	(22)	(29)	(35)	(41)	(40)	(38)	(37)	(36)	(36)
Sunflower		122	4	8	12	15	19	17	14	12	10	10
Aquila - West Plains		203	31	27	23	19	16	16	17	18	18	18
Merchants in SPP		(4,432)	(156)	(276)	(395)	(514)	(633)	(582)	(532)	(482)	(432)	(432)
Rest of Eastern Inter/Other		(2,013)	(145)	(181)	(217)	(253)	(289)	(252)	(215)	(178)	(141)	(141)
Grand Total		-	-	-	-	-	-	-	-	-	-	-

Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 6

Increase in Transmission Wheeling Charges -- Moving from Base Case to StandAlone Case

(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	139,645	19,552	20,688	21,866	23,088	24,353	23,367	22,323	21,218	20,050	20,511
Empire	IOU	40,370	6,625	6,499	6,364	6,220	6,065	6,064	6,060	6,053	6,042	6,181
KCPL	IOU	5,057	1,002	902	798	688	572	632	694	758	825	844
OGE	IOU	87,249	14,408	13,998	13,562	13,098	12,606	12,883	13,166	13,455	13,750	14,067
SPS	IOU	26,670	2,337	2,996	3,684	4,401	5,150	5,106	5,057	5,002	4,943	5,057
Westar Energy	IOU	67,678	7,071	8,094	9,160	10,272	11,429	11,954	12,497	13,059	13,640	13,953
Midwest Energy	Coop	2,818	294	337	381	428	476	498	520	544	568	581
Western Farmers	Coop	70,356	8,952	9,542	10,154	10,789	11,448	11,744	12,047	12,358	12,676	12,968
SWPA	Fed	33,261	5,103	5,089	5,071	5,050	5,026	5,122	5,220	5,319	5,421	5,545
GRDA	State	26,182	2,821	3,178	3,551	3,939	4,343	4,567	4,799	5,039	5,288	5,409
Springfield, MO	Muni	511	205	135	61	(16)	(96)	(29)	41	114	191	196
Sub-Total		499,797	68,369	71,458	74,652	77,956	81,372	81,906	82,422	82,918	83,394	85,312
Other Typical Assessment Paying Members												
AECC	Coop	10,344	1,448	1,532	1,620	1,710	1,804	1,731	1,654	1,572	1,485	1,519
Kansas City, KS	Muni	651	129	116	103	88	74	81	89	98	106	109
OMPA	Muni	8,378	1,267	1,277	1,286	1,295	1,304	1,311	1,317	1,323	1,328	1,358
Independence, MO	Muni	953	123	131	139	147	155	159	162	165	169	173
Sub-Total		20,326	2,967	3,056	3,147	3,241	3,337	3,282	3,222	3,157	3,088	3,159
Total of Above		520,124	71,336	74,514	77,800	81,197	84,710	85,188	85,644	86,076	86,482	88,471
Others												
Cleco Power		107	(3)	2	8	14	20	24	29	34	39	40
City of Lafayette, LA		21	(1)	0	2	3	4	5	6	7	8	8
LEPA		12	(0)	0	1	2	2	3	3	4	4	5
Aquila - MPS/SJ		5,694	734	780	828	877	929	948	968	988	1,009	1,032
Sunflower		(595)	(26)	(50)	(76)	(103)	(130)	(128)	(126)	(124)	(121)	(124)
Aquila - West Plains		6,427	671	769	870	975	1,085	1,135	1,187	1,240	1,295	1,325
Merchants in SPP		-	-	-	-	-	-	-	-	-	-	-
Rest of Eastern Interconnect		11,808	1,529	1,573	1,618	1,665	1,712	1,881	2,057	2,240	2,431	2,487
Grand Total		543,599	74,241	77,588	81,050	84,630	88,332	89,057	89,768	90,465	91,147	93,243

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Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 7
Increase in Transmission Wheeling Revenues -- Moving from Base Case to Stand Alone Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	136,610	18,640	19,496	20,382	21,299	22,246	22,405	22,558	22,707	22,851	23,377
Empire	IOU	20,573	2,807	2,936	3,069	3,207	3,350	3,374	3,397	3,420	3,441	3,520
KCPL	IOU	73,733	10,061	10,523	11,001	11,496	12,007	12,092	12,175	12,256	12,334	12,617
OGE	IOU	76,844	10,485	10,967	11,465	11,981	12,514	12,603	12,689	12,773	12,854	13,150
SPS	IOU	76,126	10,387	10,864	11,358	11,869	12,397	12,485	12,571	12,654	12,734	13,027
Westar Energy	IOU	67,847	9,258	9,683	10,123	10,578	11,049	11,127	11,203	11,277	11,349	11,610
Midwest Energy	Coop	6,767	923	966	1,010	1,055	1,102	1,110	1,117	1,125	1,132	1,158
Western Farmers	Coop	17,903	2,443	2,555	2,671	2,791	2,915	2,936	2,956	2,976	2,995	3,064
SWPA	Fed	12,409	1,693	1,771	1,851	1,935	2,021	2,035	2,049	2,063	2,076	2,123
GRDA	State	20,201	2,756	2,883	3,014	3,150	3,290	3,313	3,336	3,358	3,379	3,457
Springfield, MO	Muni	6,574	897	938	981	1,025	1,071	1,078	1,086	1,093	1,100	1,125
Sub-Total		515,585	70,351	73,583	76,926	80,384	83,961	84,558	85,138	85,701	86,244	88,227
Other Typical Assessment Paying Members												
AECC	Coop	10,119	1,381	1,444	1,510	1,578	1,648	1,660	1,671	1,682	1,693	1,732
Kansas City, KS	Muni	9,487	1,294	1,354	1,415	1,479	1,545	1,556	1,567	1,577	1,587	1,623
OMPA	Muni	6,549	894	935	977	1,021	1,067	1,074	1,081	1,089	1,096	1,121
Independence, MO	Muni	(83)	(6)	(9)	(12)	(15)	(18)	(17)	(16)	(15)	(14)	(14)
Sub-Total		26,073	3,563	3,724	3,891	4,063	4,241	4,273	4,303	4,333	4,361	4,462
Total of Above		541,657	73,914	77,307	80,817	84,447	88,202	88,831	89,441	90,033	90,605	92,689
Others												
Cleco Power		(659)	(211)	(170)	(127)	(83)	(36)	(42)	(48)	(54)	(60)	(62)
City of Lafayette, LA		(132)	(42)	(34)	(25)	(17)	(7)	(8)	(9)	(11)	(12)	(12)
LEPA		(75)	(24)	(19)	(15)	(9)	(4)	(5)	(5)	(6)	(7)	(7)
Aquila - MPS/SJ		(494)	(36)	(53)	(70)	(88)	(107)	(102)	(95)	(89)	(82)	(84)
Sunflower		-	-	-	-	-	-	-	-	-	-	-
Aquila - West Plains		6,443	879	920	961	1,005	1,049	1,057	1,064	1,071	1,078	1,103
Merchants in SPP		-	-	-	-	-	-	-	-	-	-	-
Rest of Eastern Interconnect		(3,141)	(239)	(362)	(490)	(625)	(765)	(674)	(579)	(480)	(375)	(384)
Grand Total		543,599	74,241	77,588	81,050	84,630	88,332	89,057	89,768	90,465	91,147	93,243

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Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 8
Costs Incurred for Provision of SPP Functions, 2006-2015

			SPP Provides Functions	Transmission Owners Provide/Procure SPP Functions	Additional Cost Incurred If StandAlone	Additional Cost Net of Allocation Below
Transmission Owners Under SPP Tariff						
AEP	IOU		28,881	28,806	(75)	(69)
Empire	IOU		4,372	5,079	707	707
KCPL	IOU		13,846	24,661	10,815	10,815
OGE	IOU		22,570	26,292	3,722	3,536
SPS	IOU		21,589	24,842	3,252	3,252
Westar Energy	IOU		21,551	35,165	13,614	13,614
Midwest Energy	Coop		879	8,701	7,822	7,822
Western Farmers	Coop		5,020	3,924	(1,096)	(1,071)
SWPA	Fed		1,102	1,111	9	9
GRDA	State	A	3,241	8,055	4,814	4,814
Springfield, MO	Muni	A	2,542	5,085	2,543	2,543
	Total		125,595	171,720	46,125	45,970
Other Typical Assessment Paying Members:						
Control Area Operators:						
Kansas City, KS	Muni	A	1,944	3,424	1,479	1,479
Independence, MO	Muni	A	1,026	1,481	455	455

Others within Control Areas:

		Avg Load Ratio Share of Control Area				Allocated Share of Addtl Cost
		AEP	OGE	Westar	WFEC	
AECC	Coop	6.8%				(5)
OMPA	Muni	1.4%	5.0%		2.3%	160
	Total	8.1%	5.0%	0.0%	2.3%	155

	Additional Cost Incurred If StandAlone	Additional Cost Net of Allocation Below
Total of Above	48,060	48,060

A: Based on average $/MWh costs for MIDW, WFEC, and SWPA.

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Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 9
Savings in FERC Fees if Stand Alone and Not Part of SPP RTO
Thousands of Dollars

		FERC Fees Based on 1999-2003 Average		Allocated FERC Fees if Part of SPP RTO		Savings in FERC Fees if Not Part of SPP RTO	
		2006	PV2006-15	2006	PV2006-15	2006	PV2006-15
TOs Under SPP Tariff							
AEP	IOU	487	3,426	1,377	9,686	889	6,260
Empire	IOU	51	360	208	1,466	157	1,106
KCPL	IOU	210	1,477	660	4,643	450	3,166
OGE	IOU	311	2,186	1,076	7,569	765	5,383
SPS	IOU	285	2,001	1,029	7,240	745	5,239
Westar Energy	IOU	762	5,354	1,027	7,228	266	1,874
Midwest Energy	Coop	0	0	42	295	42	295
Western Farmers	Coop	0	0	239	1,684	239	1,684
SWPA	Fed	0	0	53	370	53	370
GRDA	State	0	0	155	1,087	155	1,087
Springfield, MO	Muni	0	0	121	853	121	853
Sub-Total		2,106	14,805	5,988	42,120	3,881	27,315
Other Typical Assessment Paying Members							
AECC	Coop	0	0	133	934	133	934
Kansas City, KS	Muni	0	0	93	652	93	652
OMPA	Muni	0	0	111	781	111	781
Independence, MO	Muni	0	0	49	344	49	344
Sub-Total		0	0	385	2,711	385	2,711
Total of Above		2,106	14,805	6,373	44,831	4,267	30,027

Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 10

Savings/(Additional Costs) Under Stand Alone Cost Allocation Method vs. Base Case Method for 2006-2010 Transmission Projects

(thousands of revenue requirements dollars)

	2006-2010 Annual Average	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value	Present Value Net of Allocation Below
Estimated Ramp-up (A)		20%	40%	60%	80%	100%	100%	100%	100%	100%	100%		
Transmission Owners Under SPP Tariff													
AEP	(1,274)	(255)	(509)	(764)	(1,019)	(1,274)	(1,274)	(1,274)	(1,274)	(1,274)	(1,274)	(5,990)	(5,502)
Empire	(176)	(35)	(70)	(106)	(141)	(176)	(176)	(176)	(176)	(176)	(176)	(829)	(829)
KCPL	(175)	(35)	(70)	(105)	(140)	(175)	(175)	(175)	(175)	(175)	(175)	(823)	(823)
OGE	(181)	(36)	(73)	(109)	(145)	(181)	(181)	(181)	(181)	(181)	(181)	(853)	(811)
SPS	298	60	119	179	238	298	298	298	298	298	298	1,400	1,400
Westar	286	57	114	172	229	286	286	286	286	286	286	1,345	1,345
Midwest Energy	70	14	28	42	56	70	70	70	70	70	70	327	327
Westar Energy	336	67	134	201	269	336	336	336	336	336	336	1,579	1,543
SWPA	459	92	184	275	367	459	459	459	459	459	459	2,159	2,159
GRDA	128	26	51	77	103	128	128	128	128	128	128	603	603
Springfield, MO	230	46	92	138	184	230	230	230	230	230	230	1,080	1,080
Total	-	-	-	-	-	-	-	-	-	-	-	-	494

Other Typical Assessment Paying Members	Load Share of Control Area				Pres Value Allocated Share
	AEP	OGE	Westar	WFEC	
AECC	6.8%				(405)
OMPA	1.4%	5.0%		2.3%	(89)
	8.1%	5.0%	0.0%	2.3%	(494)

CRA assumed that the 2006-2010 transmission projects would enter service on a pro-rata annual basis over the 5-year period.

Appendix 4-1: Benefits (Costs) by Company for the Stand-Alone Case (cont.)

Table 11
SPP Withdrawal Obligations
(thousands of dollars)

Transmission Owners Under SPP Tariff		
AEP	IOU	12,377
Empire	IOU	1,803
KCPL	IOU	4,731
OGE	IOU	8,187
SPS	IOU	7,229
Westar Energy	IOU	6,183
Midwest Energy	Coop	670
Western Farmers	Coop	2,050
SWPA	Fed	1,297
GRDA	State	1,485
Springfield, MO	Muni	1,234
Sub-Total		47,246
Other Typical Assessment Paying Members		
AECC	Coop	1,298
Kansas City, KS	Muni	1,084
OMPA	Muni	1,022
Independence, MO	Muni	688
Sub-Total		4,092
Total of Above		51,338

Source: July 27, 2004 SPP Finance Committee Recommendation to the Board of Directors

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Revised 7/27/05

Appendix 4-2 Benefits (Costs) by Company for the EIS Market Case

Table 1
Benefits/(Costs) of Moving from Base Case to EIS Market Case
(2006-2015, thousands of January 2006 present value dollars; positive numbers indicate benefits)

	Source:	Table 3	Table 6	Table 7	Table 8	Table 9	
		Trade Benefits	Transmission Charges Paid	Transmission Charges Collected	SPP IE Implementation Costs	Participant IE Implementation Costs	Total
TOs Under SPP Tariff							
AEP	IOU	106,541	17,012	(14,092)	(24,099)	(26,860)	58,502
Empire	IOU	61,646	(66)	(2,122)	(3,648)	(7,936)	47,874
KCPL	IOU	31,082	1,249	(7,606)	(11,553)	(15,328)	(2,156)
OGE	IOU	126,375	10,435	(7,927)	(18,833)	(14,739)	95,310
SPS	IOU	100,178	2,738	(7,853)	(18,015)	(7,676)	69,372
Westar Energy	IOU	73,009	(1,221)	(6,999)	(17,983)	(19,394)	27,412
Midwest Energy	Coop	925	(51)	(698)	(733)	(132)	(689)
Western Farmers	Coop	86,958	(722)	(1,847)	(4,189)	(4,989)	75,211
SWPA	Fed	5,627	239	(1,280)	(920)	(2,472)	1,194
GRDA	State	11,775	(6,992)	(2,084)	(2,705)	(4,967)	(4,971)
Springfield, MO	Muni	10,160	1,767	(678)	(2,121)	(3,135)	5,992
	Sub-Total	614,277	24,388	(53,185)	(104,801)	(107,629)	373,050
Other Typical Assessment Paying Members							
AECC	Coop	26,131	1,260	(1,044)	(2,325)	-	24,023
Kansas City, KS	Muni	6,209	161	(979)	(1,622)	-	3,768
OMPA	Muni	17,768	792	(676)	(1,943)	-	15,941
Independence, MO	Muni	3,200	(847)	(9)	(856)	-	1,487
	Sub-Total	53,308	1,365	(2,708)	(6,746)	-	45,220
Total of Above		667,585	25,754	(55,893)	(111,547)	(107,629)	418,270
Others							
Cleco Power		12,462	1,023	10,592			24,077
City of Lafayette, LA		2,106	204	2,116			4,426
LEPA		608	117	1,211			1,936
Aquila - MPS/SJ		1,811	(5,061)	(56)			(3,307)
Sunflower		451	(1,820)	-			(1,369)
Aquila - West Plains		3,640	(116)	(665)			2,860
Merchants in SPP		123,868	-	-			123,868
Rest of Eastern Interconnect		360,049	38,589	(15,995)			382,643
Grand Total		1,172,581	58,690	(58,690)			

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 2
State Allocation for Multi-State Utilities
Benefits/(Costs) of Moving from Base Case to EIS Market Case
(2005-2014, thousands of January 2006 present value dollars)

State Allocation for Multi-State Utilities

		Retail							
	Wholesale	**Arkansas**	**Louisiana**	**Kansas**	**Missouri**	**New Mexico**	**Oklahoma**	**Texas**	**Total**
AEP	12.7%	10.8%	14.1%				44.6%	17.8%	100.0%
Empire	6.4%	3.0%		5.2%	82.7%		2.7%		100.0%
KCPL - Trade	1.0%			41.4%	57.7%				100.0%
KCPL - Other	13.5%			38.8%	47.7%				100.0%
OG&E	9.4%	10.5%					80.1%		100.0%
SPS	40.1%			0.1%		13.3%	1.2%	45.3%	100.0%
Westar Energy	12.7%			87.3%					100.0%

Allocations are based on net energy for load, except for KCPL - Other which is based on 4 summer months coincident peak and applies to all KCPL cost-benefit components other than Trade Benefits
In the calculation below, AEP trade benefits are subdivided between PSO and Swepco using the generation of each operating company before the allocation by state. PSO is in Oklahoma only, and Swepco is in Arkansas, Lousiana and Texas.

Benefits/(Costs) of Moving from Base Case to EIS Case

		Retail							
	Wholesale	**Arkansas**	**Louisiana**	**Kansas**	**Missouri**	**New Mexico**	**Oklahoma**	**Texas**	**Total**
AEP	7,430	(2,942)	(3,840)				62,703	(4,848)	58,502
Empire	3,054	1,446		2,480	39,592		1,302	-	47,874
KCPL	(4,183)			(46)	2,073				(2,156)
OG&E	8,940	10,046					76,324		95,310
SPS	27,832			69		9,219	812	31,439	69,372
Westar Energy	3,481			23,930					27,412
Total	46,555	8,550	(3,840)	26,433	41,664	9,219	141,141	26,591	296,313

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 3
Trade Benefits - EIS Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	106,541	7,263	10,281	13,434	16,726	20,163	20,905	21,670	22,459	23,274	23,809
Empire	IOU	61,646	8,663	8,881	9,105	9,334	9,569	9,847	10,133	10,427	10,728	10,975
KCPL	IOU	31,082	3,284	4,132	5,018	5,943	6,907	6,121	5,295	4,428	3,518	3,599
OGE	IOU	126,375	12,900	15,050	17,292	19,630	22,066	22,700	23,352	24,022	24,710	25,279
SPS	IOU	100,178	7,468	10,428	13,521	16,751	20,122	19,902	19,660	19,397	19,112	19,551
Westar Energy	IOU	73,009	7,011	9,135	11,353	13,668	16,084	14,549	12,935	11,239	9,458	9,676
Midwest Energy	Coop	925	80	100	120	141	163	171	180	188	197	202
Western Farmers	Coop	86,958	7,603	9,406	11,288	13,252	15,300	16,075	16,877	17,708	18,568	18,995
SWPA	Fed	5,627	573	668	767	871	979	1,010	1,042	1,075	1,108	1,134
GRDA	State	11,775	1,021	1,286	1,564	1,853	2,155	2,212	2,270	2,330	2,391	2,446
Springfield, MO	Muni	10,160	821	1,081	1,353	1,636	1,932	1,956	1,980	2,004	2,028	2,074
Sub-Total		614,277	56,686	70,450	84,816	99,806	115,440	115,447	115,393	115,276	115,092	117,739
Other Typical Assessment Paying Members												
AECC	Coop	26,131	2,840	3,820	4,844	5,913	7,029	5,594	4,090	2,513	861	881
Kansas City, KS	Muni	6,209	1,378	1,290	1,197	1,100	997	842	679	509	330	338
OMPA	Muni	17,768	2,470	2,636	2,808	2,988	3,173	3,008	2,833	2,649	2,454	2,511
Independence, MO	Muni	3,200	259	329	404	481	562	598	635	674	715	731
Sub-Total		53,308	6,946	8,075	9,254	10,482	11,761	10,042	8,238	6,345	4,360	4,461
Total of Above		667,585	63,632	78,525	94,069	110,287	127,202	125,489	123,631	121,621	119,453	122,200
Others												
Cleco Power		12,462	1,835	1,587	1,326	1,053	766	1,511	2,289	3,103	3,953	4,044
City of Lafayette, LA		2,106	233	224	214	204	193	305	422	544	672	687
LEPA		608	28	49	71	94	119	125	132	139	146	150
Aquila - MPS/SJ		1,811	1,094	767	425	67	(308)	(209)	(106)	3	116	118
Sunflower		451	(136)	(101)	(64)	(25)	16	115	219	328	441	451
Aquila - West Plains		3,640	15	305	608	925	1,256	1,009	750	479	194	199
Merchants in SPP		123,868	4,184	9,353	14,757	20,406	26,306	26,785	27,273	27,769	28,274	28,924
Rest of Eastern Interconnect		360,049	34,304	42,047	50,129	58,559	67,352	67,200	67,005	66,766	66,480	68,009
Grand Total		1,172,581	105,189	132,756	161,537	191,571	222,901	222,330	221,616	220,751	219,729	224,783

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 4
Increase in Owned Generation Production Costs -- Moving from Base Case to EIS Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	(888,481)	(127,063)	(126,334)	(125,505)	(124,570)	(123,527)	(135,638)	(148,241)	(161,352)	(174,988)	(179,012)
Empire	IOU	(169,838)	(24,840)	(24,857)	(24,861)	(24,853)	(24,831)	(26,222)	(27,665)	(29,160)	(30,710)	(31,416)
KCPL	IOU	(71,448)	(6,856)	(8,991)	(11,219)	(13,546)	(15,973)	(14,330)	(12,603)	(10,788)	(8,884)	(9,088)
OGE	IOU	(699,283)	(98,264)	(98,391)	(98,472)	(98,505)	(98,487)	(107,805)	(117,499)	(127,583)	(138,067)	(141,243)
SPS	IOU	(340,068)	(31,438)	(39,043)	(46,982)	(55,266)	(63,905)	(63,893)	(63,847)	(63,765)	(63,645)	(65,109)
Westar Energy	IOU	(63,341)	(7,997)	(7,003)	(5,959)	(4,864)	(3,715)	(8,038)	(12,559)	(17,283)	(22,218)	(22,729)
Midwest Energy	Coop	(307)	(49)	(49)	(48)	(47)	(46)	(46)	(47)	(47)	(48)	(49)
Western Farmers	Coop	(304,676)	(31,269)	(35,139)	(39,171)	(43,369)	(47,740)	(52,557)	(57,571)	(62,788)	(68,214)	(69,783)
SWPA	Fed	(2)	(0)	(0)	(0)	(1)	(1)	(1)	(0)	0	0	0
GRDA	State	802	111	110	109	107	106	121	138	155	172	176
Springfield, MO	Muni	(32,096)	(4,936)	(4,807)	(4,670)	(4,524)	(4,369)	(4,753)	(5,151)	(5,565)	(5,996)	(6,134)
Sub-Total		(2,568,737)	(332,602)	(344,505)	(356,780)	(369,437)	(382,488)	(413,162)	(445,045)	(478,176)	(512,596)	(524,385)
Other Typical Assessment Paying Members												
AECC	Coop	(68,569)	(8,018)	(9,710)	(11,475)	(13,317)	(15,237)	(13,254)	(11,171)	(8,986)	(6,694)	(6,848)
Kansas City, KS	Muni	8,086	2,042	1,860	1,667	1,465	1,253	999	733	454	162	166
OMPA	Muni	(95,492)	(11,767)	(12,758)	(13,788)	(14,859)	(15,973)	(16,231)	(16,493)	(16,759)	(17,028)	(17,419)
Independence, MO	Muni	(11,562)	(966)	(1,186)	(1,415)	(1,654)	(1,904)	(2,101)	(2,307)	(2,521)	(2,743)	(2,806)
Sub-Total		(167,537)	(18,708)	(21,794)	(25,011)	(28,365)	(31,861)	(30,587)	(29,238)	(27,811)	(26,303)	(26,908)
Total of Above		(2,736,273)	(351,310)	(366,299)	(381,791)	(397,803)	(414,349)	(443,749)	(474,283)	(505,987)	(538,898)	(551,293)
Others												
Cleco Power		(337,351)	(44,777)	(49,600)	(54,620)	(59,845)	(65,281)	(59,740)	(53,908)	(47,777)	(41,336)	(42,286)
City of Lafayette, LA		(10,562)	(1,214)	(1,095)	(970)	(839)	(701)	(1,411)	(2,152)	(2,927)	(3,737)	(3,823)
LEPA		(4,351)	(233)	(374)	(522)	(677)	(838)	(880)	(923)	(968)	(1,015)	(1,038)
Aquila - MPS/SJ		(11,834)	(4,462)	(3,531)	(2,556)	(1,534)	(463)	(457)	(451)	(443)	(436)	(446)
Sunflower		(10,206)	(1,188)	(1,176)	(1,163)	(1,148)	(1,133)	(1,535)	(1,955)	(2,393)	(2,851)	(2,916)
Aquila - West Plains		(688)	(1,470)	(839)	(178)	514	1,237	853	451	29	(412)	(421)
Merchants in SPP		2,670,459	304,351	330,856	358,419	387,075	416,859	450,306	485,070	521,195	558,725	571,576
Rest of Eastern Interconnect		(731,775)	(4,886)	(40,698)	(78,155)	(117,314)	(158,232)	(165,718)	(173,464)	(181,479)	(189,771)	(194,136)
Grand Total		(1,172,581)	(105,189)	(132,756)	(161,537)	(191,571)	(222,901)	(222,330)	(221,616)	(220,751)	(219,729)	(224,783)

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 5
Increase in Owned Generation -- Moving from Base Case to EIS Case
(Thousands of MWh)

		Total	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	(27,688)	(2,351)	(2,426)	(2,502)	(2,578)	(2,654)	(2,790)	(2,926)	(3,063)	(3,199)	(3,199)
Empire	IOU	(6,483)	(688)	(661)	(633)	(606)	(579)	(609)	(639)	(669)	(700)	(700)
KCPL	IOU	(1,774)	(160)	(194)	(228)	(262)	(296)	(235)	(175)	(115)	(54)	(54)
OGE	IOU	(18,714)	(1,650)	(1,678)	(1,706)	(1,735)	(1,763)	(1,861)	(1,958)	(2,056)	(2,154)	(2,154)
SPS	IOU	(8,732)	(426)	(573)	(719)	(866)	(1,012)	(1,018)	(1,023)	(1,028)	(1,033)	(1,033)
Westar Energy	IOU	164	(66)	21	109	196	284	155	27	(102)	(230)	(230)
Midwest Energy	Coop	(7)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Western Farmers	Coop	(9,255)	(567)	(652)	(737)	(823)	(908)	(982)	(1,055)	(1,128)	(1,202)	(1,202)
SWPA	Fed	(282)	(24)	(25)	(25)	(26)	(26)	(28)	(30)	(31)	(33)	(33)
GRDA	State	(506)	(35)	(40)	(45)	(50)	(55)	(55)	(56)	(57)	(57)	(57)
Springfield, MO	Muni	(774)	(44)	(55)	(65)	(76)	(86)	(88)	(89)	(90)	(91)	(91)
Sub-Total		(74,052)	(6,012)	(6,283)	(6,554)	(6,825)	(7,096)	(7,510)	(7,925)	(8,339)	(8,754)	(8,754)
Other Typical Assessment Paying Members												
AECC	Coop	(3,114)	(242)	(307)	(373)	(438)	(503)	(413)	(322)	(232)	(142)	(142)
Kansas City, KS	Muni	645	116	104	92	80	68	57	46	35	24	24
OMPA	Muni	(3,166)	(274)	(292)	(310)	(328)	(346)	(338)	(330)	(322)	(314)	(314)
Independence, MO	Muni	(391)	(22)	(26)	(30)	(34)	(38)	(42)	(45)	(49)	(53)	(53)
Sub-Total		(6,027)	(422)	(521)	(621)	(720)	(820)	(736)	(652)	(568)	(484)	(484)
Total of Above		(80,079)	(6,433)	(6,804)	(7,175)	(7,545)	(7,916)	(8,246)	(8,577)	(8,907)	(9,238)	(9,238)
Others												
Cleco Power		(12,347)	(1,065)	(1,194)	(1,322)	(1,450)	(1,579)	(1,425)	(1,271)	(1,117)	(963)	(963)
City of Lafayette, LA		(275)	(20)	(18)	(16)	(15)	(13)	(22)	(31)	(40)	(50)	(50)
LEPA		(76)	(2)	(4)	(5)	(7)	(8)	(9)	(9)	(10)	(11)	(11)
Aquila - MPS/SJ		(315)	(114)	(84)	(55)	(26)	3	(1)	(5)	(8)	(12)	(12)
Sunflower		(263)	(18)	(18)	(19)	(19)	(19)	(25)	(30)	(35)	(40)	(40)
Aquila - West Plains		394	1	22	43	64	85	67	50	32	14	14
Merchants in SPP		115,285	8,309	9,102	9,895	10,689	11,482	12,082	12,682	13,281	13,881	13,881
Rest of Eastern Inter/Other		(22,324)	(657)	(1,002)	(1,347)	(1,691)	(2,036)	(2,422)	(2,809)	(3,196)	(3,582)	(3,582)
Grand Total		-	-	-	-	-	-	-	-	-	-	-

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 6
Increase in Transmission Wheeling Charges -- Moving from Base Case to EIS Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	(17,012)	(1,946)	(2,163)	(2,388)	(2,622)	(2,866)	(2,948)	(3,032)	(3,118)	(3,207)	(3,281)
Empire	IOU	66	122	89	55	18	(20)	(37)	(56)	(76)	(96)	(98)
KCPL	IOU	(1,249)	(121)	(143)	(166)	(189)	(214)	(225)	(236)	(248)	(260)	(266)
OGE	IOU	(10,435)	(746)	(985)	(1,235)	(1,496)	(1,768)	(1,956)	(2,152)	(2,356)	(2,568)	(2,627)
SPS	IOU	(2,738)	-	(161)	(329)	(504)	(688)	(663)	(637)	(608)	(579)	(592)
Westar Energy	IOU	1,221	240	228	214	200	185	171	157	141	125	128
Midwest Energy	Coop	51	10	9	9	8	8	7	7	6	5	5
Western Farmers	Coop	722	74	82	89	97	106	122	138	155	173	177
SWPA	Fed	(239)	37	13	(11)	(36)	(63)	(71)	(79)	(87)	(96)	(98)
GRDA	State	6,992	930	975	1,023	1,072	1,123	1,148	1,175	1,201	1,228	1,257
Springfield, MO	Muni	(1,767)	(104)	(126)	(149)	(172)	(197)	(299)	(405)	(516)	(632)	(646)
Sub-Total		(24,388)	(1,504)	(2,180)	(2,886)	(3,624)	(4,394)	(4,750)	(5,121)	(5,506)	(5,906)	(6,042)
Other Typical Assessment Paying Members												
AECC	Coop	(1,260)	(144)	(160)	(177)	(194)	(212)	(218)	(225)	(231)	(238)	(243)
Kansas City, KS	Muni	(161)	(16)	(18)	(21)	(24)	(28)	(29)	(30)	(32)	(33)	(34)
OMPA	Muni	(792)	(67)	(83)	(99)	(116)	(134)	(145)	(156)	(168)	(180)	(184)
Independence, MO	Muni	847	116	118	120	121	123	133	143	154	165	169
Sub-Total		(1,365)	(111)	(144)	(178)	(214)	(251)	(259)	(268)	(277)	(286)	(292)
Total of Above		(25,754)	(1,615)	(2,324)	(3,064)	(3,838)	(4,645)	(5,010)	(5,389)	(5,782)	(6,191)	(6,334)
Others												
Cleco Power		(1,023)	(10)	(54)	(100)	(148)	(199)	(222)	(246)	(271)	(297)	(304)
City of Lafayette, LA		(204)	(2)	(11)	(20)	(30)	(40)	(44)	(49)	(54)	(59)	(61)
LEPA		(117)	(1)	(6)	(11)	(17)	(23)	(25)	(28)	(31)	(34)	(35)
Aquila - MPS/SJ		5,061	694	704	714	724	734	794	856	921	988	1,011
Sunflower		1,820	80	157	237	321	408	396	383	369	354	362
Aquila - West Plains		116	23	22	20	19	18	16	15	13	12	12
Merchants in SPP		-	-	-	-	-	-	-	-	-	-	-
Rest of Eastern Interconnect		(38,589)	(6,159)	(6,268)	(6,380)	(6,493)	(6,608)	(6,167)	(5,702)	(5,212)	(4,696)	(4,804)
Grand Total		(58,690)	(6,990)	(7,781)	(8,605)	(9,462)	(10,354)	(10,262)	(10,160)	(10,047)	(9,925)	(10,153)

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 7
Increase in Transmission Wheeling Revenues -- Moving from Base Case to EIS Case
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	(14,092)	(2,046)	(2,120)	(2,197)	(2,276)	(2,357)	(2,296)	(2,230)	(2,160)	(2,086)	(2,134)
Empire	IOU	(2,122)	(308)	(319)	(331)	(343)	(355)	(346)	(336)	(325)	(314)	(321)
KCPL	IOU	(7,606)	(1,104)	(1,144)	(1,186)	(1,228)	(1,272)	(1,239)	(1,204)	(1,166)	(1,126)	(1,152)
OGE	IOU	(7,927)	(1,151)	(1,193)	(1,236)	(1,280)	(1,326)	(1,291)	(1,254)	(1,215)	(1,173)	(1,200)
SPS	IOU	(7,853)	(1,140)	(1,182)	(1,224)	(1,268)	(1,313)	(1,279)	(1,243)	(1,204)	(1,163)	(1,189)
Westar Energy	IOU	(6,999)	(1,016)	(1,053)	(1,091)	(1,130)	(1,171)	(1,140)	(1,108)	(1,073)	(1,036)	(1,060)
Midwest Energy	Coop	(698)	(101)	(105)	(109)	(113)	(117)	(114)	(110)	(107)	(103)	(106)
Western Farmers	Coop	(1,847)	(268)	(278)	(288)	(298)	(309)	(301)	(292)	(283)	(273)	(280)
SWPA	Fed	(1,280)	(186)	(193)	(200)	(207)	(214)	(209)	(203)	(196)	(189)	(194)
GRDA	State	(2,084)	(303)	(314)	(325)	(337)	(349)	(339)	(330)	(319)	(308)	(316)
Springfield, MO	Muni	(678)	(98)	(102)	(106)	(110)	(113)	(110)	(107)	(104)	(100)	(103)
Sub-Total		(53,185)	(7,723)	(8,002)	(8,291)	(8,589)	(8,895)	(8,664)	(8,416)	(8,153)	(7,873)	(8,055)
Other Typical Assessment Paying Members												
AECC	Coop	(1,044)	(152)	(157)	(163)	(169)	(175)	(170)	(165)	(160)	(155)	(158)
Kansas City, KS	Muni	(979)	(142)	(147)	(153)	(158)	(164)	(159)	(155)	(150)	(145)	(148)
OMPA	Muni	(676)	(98)	(102)	(105)	(109)	(113)	(110)	(107)	(104)	(100)	(102)
Independence, MO	Muni	(9)	(6)	(5)	(4)	(3)	(1)	0	2	3	5	5
Sub-Total		(2,708)	(398)	(411)	(424)	(438)	(453)	(439)	(425)	(410)	(395)	(404)
Total of Above		(55,893)	(8,121)	(8,413)	(8,715)	(9,027)	(9,348)	(9,103)	(8,842)	(8,564)	(8,268)	(8,458)
Others												
Cleco Power		10,592	1,695	1,487	1,269	1,040	800	1,298	1,819	2,364	2,932	3,000
City of Lafayette, LA		2,116	339	297	253	208	160	259	363	472	586	599
LEPA		1,211	194	170	145	119	91	148	208	270	335	343
Aquila - MPS/SJ		(56)	(37)	(30)	(23)	(16)	(8)	1	10	19	29	30
Sunflower		-	-	-	-	-	-	-	-	-	-	-
Aquila - West Plains		(665)	(97)	(100)	(104)	(107)	(111)	(108)	(105)	(102)	(98)	(101)
Merchants in SPP		-	-	-	-	-	-	-	-	-	-	-
Rest of Eastern Interconnect		(15,995)	(963)	(1,191)	(1,430)	(1,679)	(1,938)	(2,757)	(3,613)	(4,507)	(5,440)	(5,565)
Grand Total		(58,690)	(6,990)	(7,781)	(8,605)	(9,462)	(10,354)	(10,262)	(10,160)	(10,047)	(9,925)	(10,153)

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 8
Annual SPP Assessments for Implementation and Operation of EIS Market
(Thousands of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	24,099	3,806	4,492	4,491	3,574	3,610	3,649	3,080	3,151	3,224	3,298
Empire	IOU	3,648	576	680	680	541	547	552	466	477	488	499
KCPL	IOU	11,553	1,825	2,154	2,153	1,713	1,731	1,749	1,476	1,511	1,545	1,581
OGE	IOU	18,833	2,974	3,510	3,510	2,793	2,822	2,851	2,407	2,462	2,519	2,577
SPS	IOU	18,015	2,845	3,358	3,357	2,671	2,699	2,728	2,302	2,355	2,410	2,465
Westar Energy	IOU	17,983	2,840	3,352	3,352	2,667	2,694	2,723	2,298	2,351	2,406	2,461
Midwest Energy	Coop	733	116	137	137	109	110	111	94	96	98	100
Western Farmers	Coop	4,189	662	781	781	621	628	634	535	548	560	573
SWPA	Fed	920	145	171	171	136	138	139	118	120	123	126
GRDA	State	2,705	427	504	504	401	405	410	346	354	362	370
Springfield, MO	Muni	2,121	335	395	395	315	318	321	271	277	284	290
Sub-Total		104,801	16,550	19,534	19,532	15,541	15,701	15,867	13,392	13,702	14,019	14,343
Other Typical Assessment Paying Members												
AECC	Coop	2,325	367	433	433	345	348	352	297	304	311	318
Kansas City, KS	Muni	1,622	256	302	302	241	243	246	207	212	217	222
OMPA	Muni	1,943	307	362	362	288	291	294	248	254	260	266
Independence, MO	Muni	856	135	160	159	127	128	130	109	112	114	117
Sub-Total		6,746	1,065	1,257	1,257	1,000	1,011	1,021	862	882	902	923
Total of Above		111,547	17,616	20,792	20,789	16,541	16,711	16,889	14,254	14,584	14,921	15,266
Tariff Admin Fees by others		17,266	2,743	3,215	3,214	2,558	2,584	2,611	2,204	2,255	2,307	2,360
Total EIS Costs		128,813	20,359	24,007	24,003	19,098	19,295	19,500	16,458	16,839	17,228	17,626

CHARLES RIVER ASSOCIATES

Appendix 4-2: Benefits (Costs) by Company for the EIS Market Case (cont.)

Table 9
Costs Incurred Internally by EIS Market Participants
(Thousand of Dollars)

		Present Value	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Transmission Owners Under SPP Tariff												
AEP	IOU	26,860	6,063	5,128	4,909	4,692	4,476	2,522	2,580	2,639	2,700	2,762
Empire	IOU	7,936	1,727	1,091	1,106	1,122	1,138	1,154	1,171	1,189	1,207	1,226
KCPL	IOU	15,328	2,624	2,203	2,232	2,283	2,291	2,343	2,397	2,453	2,509	2,567
OGE	IOU	14,739	2,524	2,366	2,356	2,357	2,359	2,021	2,067	2,115	2,163	2,213
SPS	IOU	7,676	1,638	1,452	1,404	1,356	1,308	748	766	783	801	820
Westar Energy	IOU	19,394	3,670	2,986	2,950	2,957	2,966	2,976	2,987	2,605	2,665	2,727
Midwest Energy	Coop	132	138	-	-	-	-	-	-	-	-	-
Western Farmers	Coop	4,989	931	691	707	723	739	756	774	792	810	829
SWPA (A)	Fed	2,472	479	354	353	360	366	371	375	379	383	388
GRDA (A)	State	4,967	942	697	707	721	736	749	763	777	791	805
Springfield, MO (A)	Muni	3,135	595	440	446	455	464	473	481	490	499	508
Sub-Total		107,629	21,330	17,407	17,169	17,026	16,844	14,114	14,361	14,221	14,529	14,844
Other Typical Assessment Paying Members												
AECC	Coop	-										
Kansas City, KS	Muni	-										
OMPA	Muni	-										
Independence, MO	Muni	-										
Sub-Total		-	-	-	-	-	-	-	-	-	-	-
Total of Above		107,629	21,330	17,407	17,169	17,026	16,844	14,114	14,361	14,221	14,529	14,844

A: Estimated based on the cost per mWh of Net Energy for Load of Western Farmers

Appendix 4-3 Costs Incurred for Provision of SPP's Current Functions

1. Introduction

In addition to its long-running role as a NERC reliability council, SPP performs six additional reliability/transmission provider functions for transmission-owning members: reliability coordination, tariff administration, OASIS administration, ATC/TTC calculations, scheduling agent, and regional transmission planning. As part of this cost-benefit study, CRA was asked to evaluate the costs and benefits to SPP transmission owners that result from SPP's provision of these additional functions.

Overall, SPP's provision of these additional functions is estimated to provide cost savings to the eleven transmission owners under the SPP tariff of $46.1 million (January 1, 2006 present value) over the 2006–2015 period. However, as discussed below, individual transmission owner savings vary depending in large part on the extent to which transmission provider functions and responsibilities have been transferred from the transmission owning member's facilities and resources to the SPP. The level of transmission provider functions and responsibilities maintained by an individual transmission owner provides the foundation for self-provision of all transmission provider functions. This foundation varies among the transmission owning members in the SPP.

To perform this evaluation, (1) the specific functions currently performed by SPP were defined, (2) the projected annual charges to each transmission owner for SPP to supply the additional reliability/transmission provider functions were estimated, (3) the annual costs each transmission owner would incur to perform or procure these additional reliability/transmission provider functions if SPP did not provide them were estimated, and (4) the difference between these two sets of costs was calculated to derive the cost saving that each transmission owner obtains from SPP provision of these additional functions. Each of these four steps is described in detail below.

1.1. Additional Functions Currently Performed by SPP

For purposes of this study, SPP's role as a NERC reliability council is defined as SPP Function 1, and it is assumed that SPP would continue to provide this function for member companies. The additional reliability/transmission provider functions currently performed by SPP are categorized as SPP Functions 2 through 7, defined below.

SPP Function 2: Reliability Coordination

As a NERC-recognized reliability coordinator, SPP maintains the reliability of the electric transmission system of its members and has the authority to direct actions required to maintain adequate regional generation capacity, adequate system voltage levels, and transmission system loading within specified limits. SPP also coordinates planned transmission and generation outages with its members and neighbors. The primary method utilized by SPP to relieve excessive loading on transmission facilities is NERC's Transmission Loading Relief (TLR) procedure.

SPP Function 3: Tariff Administration

SPP administers an Open Access Transmission Tariff (OATT) providing regional transmission service in all or part of eight southwestern states. Tariff-related services are as follows: calculating and posting ATC, which is broken out as a separate function below; processing requests for service; performing impact and facility studies; performing generation interconnection studies; providing tariff billing; providing revenue and transmission construction cost recovery distribution; and providing regulatory assistance.

SPP Function 4: OASIS Administration

SPP administers an Open Access Same-time Information System (OASIS) for administration of transmission service, including provision of qualified staff and supervision for day and night coverage and procurement and maintenance of the necessary telecommunications infrastructure to support the service. SPP also maintains and updates various transmission information and OATT business practice documents.

SPP Function 5: ATC/AFC/TTC Calculations

SPP calculates and maintains current and projected ATC/AFC/TTC/TRM figures. SPP utilizes these data to respond to requests for transmission service. SPP also maintain a "Scenario Analyzer" that allows a transmission customer to estimate available transmission capacity.

SPP Function 6: Scheduling Agent

SPP administers and approves regional scheduling through an electronic scheduling system known as RTO_SS (Regional Transmission Organization Scheduling System). SPP acts as a scheduling entity for all interchange transactions using SPP regional transmission service. For one transmission-owning member, SPP provides Control Area level scheduling approval service.

SPP Function 7: Regional Transmission Planning

SPP is responsible for planning, and for directing or arranging, transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and non-discriminatory transmission service across the SPP region. SPP also coordinates planning efforts with transmission owners and appropriate state authorities.

1.2 SPP Charges to Transmission Owners for Provision of Functions 2 through 7

SPP estimated the costs it incurs to provide Functions 2 through 7 based directly on its annual budgeting process. In making this estimate, SPP deducted from its total annual budgeted expenditures the budgeted costs associated with the following:

1) Reliability council activities (SPP Function 1)
2) FERC fees that will be assessed directly to SPP rather than to SPP members once SPP is an RTO
3) SPP market development activities related to implementation of an energy imbalance market and other market/RTO development activities

As noted above, it is assumed for purposes of this study that SPP continues to serve as a NERC reliability council (SPP Function 1); these costs are therefore removed from the total SPP budget in arriving at the net cost for SPP provision of Functions 2 through 7. The FERC fees payable to FERC by member companies will be assessed directly to SPP when SPP is an RTO, and then in turn assessed by SPP to member companies. These fees must therefore be removed from the total SPP budget in arriving at the net cost for SPP provision of Functions 2 through 7. Finally, the SPP budget includes significant expenditures to develop and implement the Energy Imbalance market and further market/RTO development. These costs must therefore also be removed from the total SPP budget in arriving at the net cost for SPP provision of Functions 2 through 7.

The SPP budgets for 2006 and 2007 were analyzed. The total SPP budget for 2006 is $55.7 million. The net amount attributable to provision of SPP Functions 2 through 7 was estimated to be $21.6 million. Similarly, the total SPP budget for 2007 is $63.0 million, of which $23.2 million was estimated to be attributable to provision of SPP Functions 2 through 7. SPP annual budget projections are available only through 2007. Expenditures by SPP for Functions 2 through 7 thereafter are assumed to increase at the general rate of inflation.

The eleven transmission-owning members under the SPP tariff pay membership fees, NERC assessments, and SPP assessments to SPP. The membership fees and NERC assessments are intended to compensate SPP for expenditures related to reliability council activities (SPP Function 1). Remaining SPP expenditures are recovered through an SPP assessment for many SPP members (including all eleven transmission owners under the SPP tariff) along with Schedule 1 tariff fees for other SPP members and customers.[1]

The total SPP projected costs for Functions 2 through 7 were allocated individually to the eleven SPP transmission owners under the SPP tariff using each owner's share of the annual total SPP Assessment.[2] For example, American Electric Power was allocated 18.7%, or $4.0 million, of the $21.6 million in SPP costs incurred in providing Functions 2 through 7 in 2006.

1.3 Transmission Owner Costs to Perform/Procure SPP Functions 2 Through 7 if Not Provided by SPP

To perform this evaluation, each SPP transmission owner was asked to estimate the additional costs it would incur over the 2006–2015 period to perform or procure the six additional functions currently performed by SPP.

These additional costs were separated into salaries, benefits, other O&M, and capital additions. By default, SPP budget estimates for the provision of Functions 2 through 7 include administrative and general (A&G) expenditures (e.g., office space and supplies) incurred at SPP. A similar application of A&G expenditures must therefore be added to the transmission owner costs. Using historical A&G (net of benefits) to salary ratios at each transmission owner, A&G expenditures were estimated by applying these ratios to the salary costs estimated by each transmission owner.[3]

CRA converted these wage, benefits, other O&M, capital additions, and A&G inputs into the annual revenue that would be required for each transmission owner to perform or procure the six additional functions currently performed by SPP. To arrive at the annual revenue requirement, capital additions were depreciated over the expected book life of each asset acquired, and return, associated income taxes, and property taxes were applied.

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[1] Those members paying a SPP Assessment are also assessed Schedule 1 charges; payment of these Schedule 1 charges is credited against the member's SPP Assessment.

[2] Each member's SPP Assessment is based on the member's share of the total SPP Schedule 1 billing units and total SPP member load eligible to take, but not taking, Network Integration Transmission Service.

[3] A similar method is traditionally used to assign A&G expenditures to the transmission function in developing OATT transmission rates, meaning that these additional A&G costs would be assigned to transmission in determining transmission rates if these costs were incurred by the transmission owner. While it is plausible that incremental short-term expenditures at the transmission owner would not cause a commensurate increase in transmission owner A&G costs, given that this study encompasses a 10-year horizon and that transmission owner costs are being compared to SPP costs that include a full allocation of A&G, a full allocation of A&G was also applied to transmission owner costs.

To refine the data, CRA made follow-up data requests and met with respondents to evaluate the assumptions applied by each transmission owner.

Each transmission owner faces a unique situation in performing these additional functions, depending on the tasks it currently performs. Some transmission owners, such as Midwest Energy, perform little in the way of transmission-related operating functions, and would have to expend considerable sums to develop the capabilities to perform these functions. Others, based on particular aspects of their control area, continue to perform some transmission-related tasks, and adding new functions would require smaller incremental expenditures.

Summarized below are some of the key factors that drive the additional costs that would be incurred by each transmission owner.[4] The transmission owners are grouped first by those currently under the SPP tariff, and next by other responding transmission owners.

1.3.1 Transmission Owners Under the SPP Tariff

American Electric Power (AEP)

The AEP-west control area located in SPP comprises Public Service of Oklahoma, Southwestern Electric Power Company, and a small portion of AEP Texas North Company. For Functions 2 (Reliability Coordinator) and 5 (ATC/AFC calculations), AEP estimated its additional costs for the AEP-west control area if SPP did not provide these functions using the amounts it paid PJM to provide similar services in the AEP-east control area. For Function 3 (Tariff Administration), SPP had performed these services under contract for the AEP-east control area, and these costs were used as an estimate for the AEP-west control area. In addition, it was estimated that one full-time equivalent (FTE) employee would be required to perform the incremental billing functions associated with Function 3. With regard to Function 4 (OASIS Administration), AEP's hardware and support costs for the AEP-east OASIS were used to estimate the cost if AEP-west were to perform this function. AEP estimates that it would require eight additional FTEs in the AEP-west control area to perform Functions 6 (Scheduling) and 7 (Regional Transmission Planning). Due to the combined operation of the AEP-west control area, cost and staffing figures were developed jointly for the three individual AEP-west operating companies.

Empire

SPP provides complete tariff services for Empire. Empire's five transmission operators spend only a small fraction of their time on Reliability Coordination (Function 2), and approximately three Empire District FTEs complement the services SPP provides to Empire for Functions 3 through 7. If SPP were to not supply Functions 2 through 7 to Empire, the utility estimates that nine additional FTEs would be needed. In addition, $250,000 in capital costs would be incurred for computer hardware, software, and licenses in 2006.

Grand River Dam Authority

Grand River Dam Authority did not provide information for Part 1 of this study. For purposes of this study, costs were estimated using the average cost per net energy of load derived for the other non-investor-owned transmission owners under the SPP tariff (Midwest Energy, Southwestern Power Administration, and Western Farmers).

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[4] The assumptions provided are solely for the analytic purposes defined in this study, and do not imply that any entity would be adding or removing staff based upon any outcome of this study.

Kansas City Power & Light

Kansas City Power & Light currently sells only network service under its existing OATT. It estimates that its would require nineteen additional FTEs to perform the services now provided by SPP for Functions 2 through 7. In addition, $975,000 would be required for the purchase of OASIS, tariff administration, and accounting hardware and software in 2006.

Midwest Energy

Midwest Energy relies on SPP for provision of Functions 2 through 7, and has minimal staff and associated equipment related to these functions. Midwest Energy does not sell any new service under its existing tariff, and does not operate its own independent OASIS site. Midwest Energy estimates that it would require seven FTEs to perform these SPP functions internally. In addition, $670,000 in capital costs would be incurred for computer hardware and software in 2006.

Oklahoma Gas & Electric

Oklahoma Gas & Electric currently uses Open Access Technology International (OATI) and RTO_SS on its system, and estimates that it would require seventeen additional FTEs if it were to perform Functions 2 through 7 internally. Some additional payments to OATI would be required. In addition, an estimated $700,000 in start-up costs and expenditures for new computer hardware and software would be required in 2006.

Southwestern Public Service

An additional thirteen FTEs would be required at Southwestern Public Service to perform Functions 2 through 5 and Function 7. Scheduling (Function 6) would probably be procured from OATI at roughly $35,000 per year if not obtained from SPP. Some additional labor would be required to coordinate with OATI. OASIS administration would require labor for set-up and maintenance in addition to hardware/software expenses. Additional expenditures of $25,000 for computer hardware and software in 2006 also would be required to perform these functions.

Southwestern Power Administration

The costs that Southwestern Power Administration would incur for Function 2 (Reliability Coordination) and Function 4 (OASIS Administration) were estimated on the assumption that these functions would be procured from the Tennessee Valley Authority. Existing Southwestern Power Administration staff would perform the four other SPP functions without a further increase in staffing.

Springfield, Missouri

City Utilities of Springfield, Missouri did not provide information for Part 1 of this study. For purposes of this study, costs were estimated using the average cost per net energy of load derived for the other non-investor-owned transmission owners currently under the SPP tariff (Midwest Energy, Southwestern Power Administration, and Western Farmers).

Westar Energy

Westar Energy does not sell any new service under its existing tariff, performs few functions on its OASIS system, and does only minor work with respect to calculating ATC/AFC on its system.[5] It estimates that it would require nineteen additional FTEs, including IT support, to perform Functions 2 through 7. In addition, roughly $1 million in capital costs would be incurred for the purchase of OASIS, tariff administration, scheduling, and accounting hardware and software in 2006.

Western Farmers

Western Farmers estimates that it would require three additional FTEs, $35,000 per year in additional O&M, and capital investment of $160,000 to provide Functions 2 through 7.

1.3.2 Other Control Area Operators Paying a SPP Assessment

The Board of Public Utilities of Kansas City, Kansas, and City Power and Light, of Independence, Missouri, did not provide information for Part 1 of this study. For purposes of this study, costs were estimated using the average cost per net energy of load derived for the other non-investor-owned transmission owners currently under the SPP tariff (Midwest Energy, Southwestern Power Administration, and Western Farmers).

1.4 Results

Table 1 lists the cost savings over 2006–2015 that would result from the SPP provision of Functions 2 through 7.[6] The total cost savings to the Transmission Owners under the SPP Tariff are $46.1 million (January 2006 present value) over this period. Table 2 provides annual detail for the cost savings over the 2006-2015 period. Table 3 gives further details on the calculation of the SPP charges for Functions 2 through 7.

Savings vary from owner to owner because of the specific characteristics noted above regarding their respective control areas. Midwest Energy and Westar rely on SPP for nearly all responsibilities related to Functions 2 through 7 and thus would incur considerable additional costs if SPP were no longer to supply these functions. Oklahoma Gas & Electric and Southwestern Public Service continue to supply certain transmission-related functions that could be used as a foundation for performing Functions 2 through 7, and thus their resulting savings, while significant, are lower. On the low end of cost savings, AEP's costs to procure or supply Functions 2 through 7 are roughly in line with the costs that AEP would be charged by SPP for provision of these functions, and Western Farmers' costs would be somewhat lower under self-provision.

As a general observation, most transmission owner projections are based on a presumption that transmission functions currently performed internally by each owner would continue over the next 10 years. However, over the longer term, additional responsibilities might be transferred to SPP, creating opportunities for greater cost savings than estimated here.

[5] Westar Energy administers only a few grandfathered Transmission Service Agreements. All new requests for transmission service in the Westar Energy system are submitted to and processed by SPP according to the SPP OATT.
[6] A discount rate of 10% was applied to obtain present values.

Table 1

Costs Incurred for Provision of SPP Functions 2 through 7, 2005-2014

Millions of January 1, 2006 Present Value Revenue Requirement Dollars

		SPP Provides Functions 2 to 7	Transmission Owners Provide/Procure Functions 2 to 7	Additional Cost If StandAlone
Transmission Owners Under SPP Tariff				
AEP	IOU	28.9	28.8	(0.1)
Empire District	IOU	4.4	5.1	0.7
Kansas City Power & Light	IOU	13.8	24.7	10.8
Oklahoma Gas & Electric	IOU	22.6	26.3	3.7
Southwestern Public Service	IOU	21.6	24.8	3.3
Westar	IOU	21.6	35.2	13.6
Midwest Energy	Coop	0.9	8.7	7.8
Western Farmers	Coop	5.0	3.9	(1.1)
Southwestern Power Authority	Fed	1.1	1.1	0.0
Grand River Dam Authority	State	3.2	8.1	4.8
City of Springfield	Muni	2.5	5.1	2.5
Total		125.6	171.7	46.1
Other Control Area Operators				
Board of Public Util.,Kansas City	IOU	1.9	3.4	1.5
City P&L, Independence, MO	IOU	1.0	1.5	0.5

Table 2: Cost Incurred for Provision of SPP Functions 2 Through 7

STAND ALONE COST FOR UTILITY TO PERFORM/PROCURE FUNCTIONS 2-7 (000$)

			PrValue	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
TOs Under the SPP Tariff													
	IOU	AEP	28,806	4,337	4,154	4,250	4,348	4,448	4,550	4,654	4,762	4,871	4,983
	IOU	Empire District	5,079	819	821	824	721	737	754	771	789	807	826
	IOU	KCPL	24,661	3,940	3,388	3,466	3,546	4,315	3,711	3,796	3,884	4,726	4,064
	IOU	OGE	26,292	4,008	4,011	4,065	3,881	3,969	4,051	4,144	4,240	4,337	4,437
	IOU	SPS	24,842	2,715	3,573	3,920	4,033	4,091	3,975	4,234	4,316	4,399	4,484
	IOU	Westar	35,165	5,190	5,269	5,357	5,386	5,487	5,438	5,563	5,691	5,822	5,956
	Coop	Midwest Energy	8,701	1,385	1,397	1,409	1,422	1,231	1,259	1,287	1,316	1,346	1,377
	Coop	Western Farmers	3,924	566	586	596	608	619	630	617	631	645	661
	Fed	SWPA	1,111	158	162	165	169	173	177	181	185	190	194
*	State	GRDA	8,055	1,237	1,258	1,273	1,290	1,186	1,211	1,223	1,251	1,279	1,309
*	Muni	City of Springfield	5,085	781	794	804	814	749	765	772	790	807	826
	Total		171,720	25,137	25,413	26,131	26,217	27,006	26,521	27,245	27,854	29,230	29,116
Other Control Area Operators													
*	Muni	KACY	3,424	526	535	541	548	504	515	520	532	544	556
*	Muni	INDN	1,481	227	231	234	237	218	223	225	230	235	241

* *Based on average $/MWh costs for WesternFarmers, Midwest Energy and SWPA.*

SPP ASSESSMENT FOR FUNCTIONS 2-7 (000$)

		PrValue	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
TOs Under the SPP Tariff												
IOU	AEP	28,881	4,035	4,350	4,289	4,388	4,488	4,592	4,697	4,805	4,916	5,029
IOU	Empire District	4,372	611	659	649	664	680	695	711	727	744	761
IOU	KCP&L	13,846	1,934	2,085	2,056	2,103	2,152	2,201	2,252	2,304	2,357	2,411
IOU	OGE	22,570	3,153	3,399	3,352	3,429	3,508	3,588	3,671	3,755	3,842	3,930
IOU	SPS	21,589	3,016	3,252	3,206	3,280	3,355	3,432	3,511	3,592	3,675	3,759
IOU	Westar	21,551	3,011	3,246	3,200	3,274	3,349	3,426	3,505	3,586	3,668	3,753
Coop	Midwest Energy	879	123	132	131	134	137	140	143	146	150	153
Coop	Western Farmers	5,020	701	756	745	763	780	798	816	835	854	874
Fed	SWPA	1,102	154	166	164	167	171	175	179	183	188	192
State	GRDA	3,241	453	488	481	492	504	515	527	539	552	564
Muni	City of Springfield	2,542	355	383	378	386	395	404	413	423	433	443
Total		125,595	17,548	18,916	18,651	19,080	19,519	19,968	20,427	20,897	21,378	21,869
Other Control Area Operators												
Muni	KACY	1,944	272	293	289	295	302	309	316	324	331	339
Muni	INDN	1,026	143	154	152	156	159	163	167	171	175	179

ADDITIONAL COST IF STANDALONE (000$)

		PrValue	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
TOs Under the SPP Tariff												
IOU	AEP_SPP	(75)	302	(195)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(46)
IOU	EmpireDistrict	707	208	163	175	56	58	59	60	62	63	65
IOU	KCPL	10,815	2,005	1,303	1,410	1,442	2,163	1,510	1,544	1,580	2,369	1,653
IOU	OGE	3,722	854	611	713	452	461	463	473	484	495	507
IOU	SPS	3,252	(301)	321	714	753	736	543	723	724	725	725
IOU	Westar	13,614	2,179	2,023	2,157	2,112	2,138	2,012	2,058	2,105	2,154	2,203
Coop	MWEnergy	7,822	1,263	1,265	1,279	1,289	1,094	1,119	1,144	1,170	1,197	1,224
Coop	WesternFarmers	(1,096)	(135)	(170)	(149)	(155)	(161)	(168)	(199)	(204)	(209)	(213)
Fed	SWPA	9	4	(4)	2	2	2	2	2	2	2	2
State	GRDA	4,814	784	770	792	797	683	696	696	711	727	744
Muni	City of Springfield	2,543	426	411	426	428	354	361	359	367	375	383
Total		46,125	7,589	6,497	7,480	7,137	7,487	6,553	6,818	6,957	7,852	7,247
Other Control Area Operators												
Muni	KACY	1,479	254	242	252	253	202	206	204	208	213	218
Muni	INDN	455	84	77	82	81	59	60	58	59	61	62

Table 3: SPP Assessments for SPP Functions 2 through 7

			2006 Projection			2007 Projection
Total SPP Budgeted Costs			55,675,550			63,043,003
less Member Fees			(1,100,000)			(1,100,000)
less NERC Assessment			(723,180)			(737,644)
less FERC Fees Assessment			(7,344,000)			(7,490,880)
less Miscellaneous Income			(1,080,000)			(1,080,000)
SPP Assessment Required			45,428,368			52,634,477
less Market Development costs			(23,842,553)			(29,388,064)
SPP Assessments for Functions 2-7			21,585,815			23,246,413
Members Paying SPP Assessment	**2006 Assessments**	**Share**	**Cost for Functions 2-7**	**2007 Assessments**	**Share**	**Cost for Functions 2-7**
AEP - SWEPCO & PSO	8,417,687	18.7%	4,035,126	9,848,694	18.7%	4,349,750
Oklahoma Gas & Electric Company	6,578,373	14.6%	3,153,427	7,696,696	14.6%	3,399,304
Southwestern Public Service Company	6,292,501	14.0%	3,016,391	7,362,226	14.0%	3,251,583
Westar Energy-(KGE&KPL)	6,281,445	13.9%	3,011,091	7,349,291	14.0%	3,245,870
Kansas City Power & Light Company	4,035,525	9.0%	1,934,480	4,721,564	9.0%	2,085,314
Western Farmers Electric Cooperative	1,463,161	3.2%	701,385	1,711,898	3.3%	756,073
Empire District Electric Company	1,274,376	2.8%	610,888	1,491,020	2.8%	658,520
Grand River Dam Authority	944,732	2.1%	452,869	1,105,336	2.1%	488,180
Arkansas Electric Cooperative Corporation	811,947	1.8%	389,217	949,978	1.8%	419,565
Southwestern Power Administration	321,233	0.7%	153,987	375,843	0.7%	165,994
City Utilities, Springfield, Missouri	740,965	1.6%	355,191	866,929	1.6%	382,886
Board of Public Util., Kansas City,KS	566,724	1.3%	271,666	663,067	1.3%	292,849
Oklahoma Municipal Power Authority	678,595	1.5%	325,293	793,956	1.5%	350,657
East Texas Electric Coop.	89,517	0.2%	42,911	104,735	0.2%	46,257
Northeast Texas Electric Coop.	775,511	1.7%	371,751	907,348	1.7%	400,737
Tex-La Electric Coop. of Texas	113,975	0.3%	54,635	133,351	0.3%	58,895
Kansas Electric Power Coop. (KEPCo)	279,516	0.6%	133,990	327,034	0.6%	144,437
City Power & Light, Independence,Missouri	298,920	0.7%	143,291	349,736	0.7%	154,464
Midwest Energy, Inc.	256,192	0.6%	122,809	299,745	0.6%	132,385
	40,220,895	89.3%	19,280,398	47,058,447	89.4%	20,783,720
Tariff Admin Fees paid by other customers	4,809,335	10.7%	2,305,416	5,576,030	10.6%	2,462,696
TOTAL	45,030,230	100.0%	21,585,814	52,634,477	100.0%	23,246,416

CHARLES RIVER ASSOCIATES

Appendix 4-4 Costs Incurred Internally by EIS Market Participants

In addition to assessments for SPP expenditures, participants in the EIS market will incur significant expenditures for increased labor and for computer hardware and software. In response to a data request by CRA, each potential EIS market participant provided a detailed estimate of the additional annual labor, O&M, and capital costs that would be required over the study period to participate in the EIS market. CRA converted these costs to annual revenue requirements and are summarized in Table 2-6 in Appendix 4-2.

CRA discussed the responses to its data request with respondents to help ensure consistency in approach. Table 1 summarizes the additional annual FTEs and labor and benefit costs for the year 2008 estimated by each participant. The table also lists the projected capital costs over the entire study period.

Table 1

Incremental Costs Incurred Internally by EIS Market Participants

(Thousands of 2005 Dollars)

Summary of 2008 Expenses by Company

	AEP	Empire	KCPL	OGE	SPS	Westar	WFEC
Incremental FTEs							
Project Management	-	-	1.0	-	-	-	-
Business	12.0	3.0	10.3	2.5	6.0	-	2.0
IT	3.0	3.0	2.5	1.8	1.0	4.0	1.0
Other	-	1.0	-	4.0	-	-	1.0
Total	15.0	7.5	13.8	8.3	8.3	15.0	4.0
Incremental Expenses (K$)							
Direct Labor (Wages)	800	450	1,089	796	420	1,245	250
Benefits	400	180	436	282	168	495	120
SubTotal	1,200	630	1,525	1,078	1,078	1,740	370
Other O&M							
Professional Services	-	50	30	-	-	25	250
Travel	-	10	38	10	15	7	10
Software/hardware	1,000	150	317	124	50	400	-
Other (specify)	-	5	175	-	-	-	-
SubTotal	1,000	215	560	134	65	432	260
Incremental A&G	-	-	-	551	-	-	30
Total Expenses	2,200	845	2,085	1,763	653	2,172	660

Summary of 2006-14 Capital Additions by Company

(including start-up capital spent in late 2005)

	AEP	Empire	KCPL	OGE	SPS	Westar	WFEC
Total Capital Additions	8,700	1,200	-	1,625	2,500	2,500	-

Cost estimates vary considerably from participant to participant, in large part because each participant has a different perspective on how it will interface with the IES market and on the amount of risk it will take on in undertaking active management of its IES market participation.

Three transmission owners under the SPP tariff (GRDA, SWPA and City of Springfield) did not provide data, and their additional costs were estimated using the average cost per MWh for Western Farmers. No data are available for the costs that might be incurred by EIS market participants that are not transmission owners under the SPP tariff. While these costs likely exist, no cost has been included in this study for these participants.

Southwest Power Pool

Southwest Power Pool, Inc.

MARKET MONITORING UNIT AND EXTERNAL MARKET ADVISOR
Report to SPP Board of Directors/Members Committee
April 22, 2008

Estimation of Net Trade Benefits from EIS Market

Executive Summary

The SPP Board of Directors requested estimates of the net trade benefits resulting from the first twelve months of the Energy Imbalance Service (EIS) market. Importantly, the Board asked that the estimates be based on actual EIS Market results rather than on simulation models. The study estimated the net trade benefits within the initial 12 months of the market to be $103 million. This value is about 20% higher than estimated with the 2005 CRA cost-benefit study, which is primarily attributed to higher actual natural gas prices than the price forecast for 2007 in the CRA study.

Background

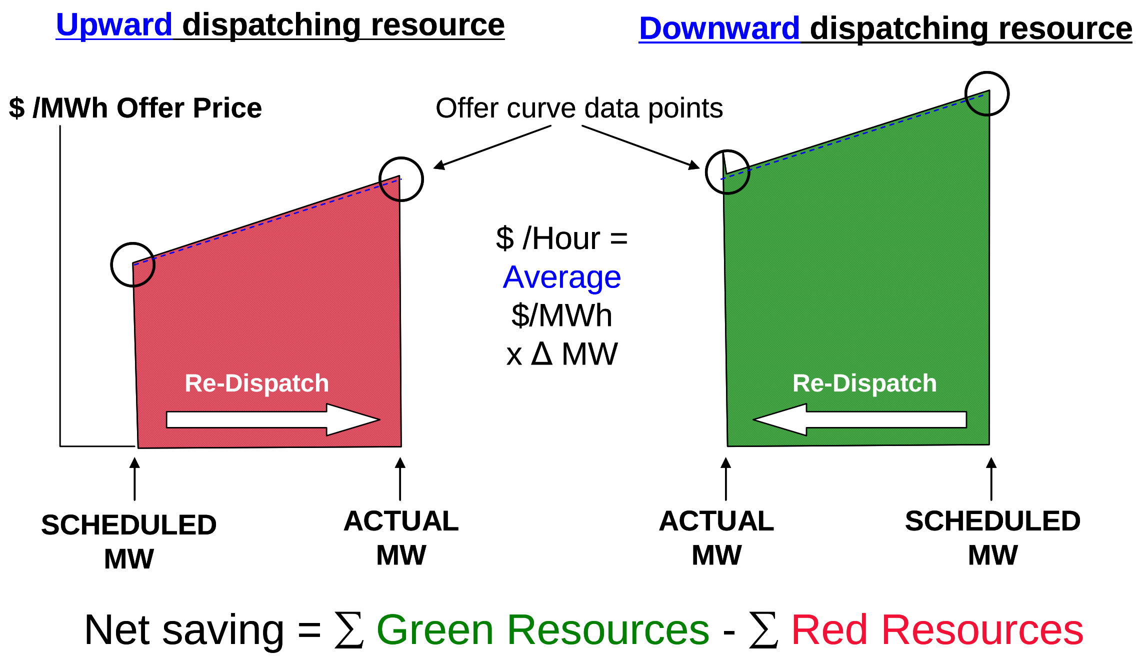
Trade benefits here refer to the amount that the short-term costs of producing electricity within the market footprint were reduced as a result of the regional security-constrained economic dispatch (SCED) implemented for the EIS market.

The EIS market SCED process seeks and carries out economic dispatch based on the prices offered by participating generating resources, issues the associated deployment instructions, and calculates the marginal price of delivery at each location within the market (i.e., the locational imbalance prices or LIPs). The market deployment thus reflects higher-priced resources being dispatched downward from scheduled levels and lower-priced resources being dispatched upward to the extent feasible while maintaining transmission network loadings within secure limits. At each participating resource (and more generally at each market settlement location) the resultant difference between actual MW level and the original scheduled MW level represents Imbalance Energy, which is priced at the LIP.

The study was conducted at a broad empirical level, utilizing data readily obtainable from the EIS market and other data collected on an ongoing basis. The SPP Market Development & Analysis department and Boston Pacific Company, Inc. (BP) conducted the simplified analysis described here to estimate the trade benefits which resulted from the first 12 months of the EIS market (February 2007 through January 2008).

The Study Methodology and Results

The empirical study first calculated the difference between actual MW output and scheduled MW output at each resource participating in the EIS market within each dispatch interval to quantify MW impacts of the EIS market. The prices along the offer curves submitted for each resource were then usedto estimate the associated impact on the costs of producing electricity. The offer curves are assumed to represent underlying marginal costs of the resources. For each resource, an interpolation of the offer-prices at the scheduled MW level and the actual MW level provides an estimation of the marginal price of production (in $ /MWh Each upward MW imbalance instance represents an estimated cost <u>incurred</u> through the EIS market dispatch, and each downward MW imbalance instance represents an estimated <u>avoided</u> cost through the EIS market dispatch. An aggregation of all of these instances for resources dispatched by the EIS market thus provides an estimation of the net cost impact of the EIS market dispatch for the time span, again referred to here as the EIS market trade benefit. It is important to note that this analysis is valid at an aggregate regional basis, since the benefit is the net of all the resource movements. The basic analysis is pictured below.



In addition to calculating incremental and avoided cost for each hour, the impact of intermittent resources and over/under scheduling to load was calculated and removed. The impact of intermittent resources would have been realized regardless of the EIS Market and was removed for comparability. On an aggregate basis there has been a net over-scheduling to load during the twelve months which would be reflected as a trade benefit if unadjusted. The impact of intermittent resources and over/under scheduling to load was removed at the highest offer price of any resource available to the market at its scheduled output MW; the highest offer price within each BA was thought to be representative of marginal cost. [1]

In addition to the detailed calculation, SPP staff also performed a validation by applying the average change in offer curve based prices to the net change in output of the resources. The net change in MWh settled through the EIS Market was 7,560 GWh. The average estimated cost avoided was $52/MWh and the average estimated cost incurred was $38/MWh. Applying the net change of $14/MWh to the 7,560 GWh yields an estimated regional trade benefit of $107 million. This is comparable to the detailed calculation results of $103 million.

The CRA Cost-Benefit Study of 2004-2005

During 2004 and 2005, Charles River Associates (CRA) conducted a study of the benefits and costs associated with the SPP EIS market, which involved extensive simulation modeling and related activities. The final report published April 23, 2005 [2] quantified a year 2007 (full year) trade benefits within the EIS market footprint of $86 million.[3]

The CRA study involved detailed simulation of years 2006, 2010 and 2014, with interpolation applied to estimate results for the intervening years. The net trade benefits quantified within the CRA study reflected the difference in the overall costs to produce electricity from a detailed simulation of the wholesale market with implementation of the EIS market in comparison to a simulation of the wholesale market without implementation of the EIS

[1] The non-market resources were excluded for this purpose, since these resources (self-scheduled and manual status assignments) would not be expected to represent those which would be marginally-dispatched by the BA in absence of the EIS market

[2] A revised CRA report was published July 27, 2005 but which did not impact the computation of overall net trade benefit.

[3] The $86 million value was derived from Table 3 of Appendix 4-2, representing the total of headings ‘Transmission Owners Under SPP Tariff’, ‘Other Typical Assessment Paying Members’ and ‘Merchants in SPP’ (all totaling $88 million), less the values estimated for 3 Members subsequently not within the EIS market footprint ($2 million impact).

market. The ten year trade benefit for the SPP region was $772 million ($1.1 billion for the Eastern Interconnect).

Additional Comparative Comments

The benefit calculated by the SPP empirical study was $103 million compared to the CRA study of $86 million. The gas costs increased about 20% over the original CRA study for the year of 2007. As noted in the 2007 State of the Market report, the marginal generation is not always gas generation. This allows a dispatch that can access non-gas generation to capitalize on the gap between increased gas prices and other generation fuel types. The non-firm bilateral transactions (schedules) approximate the pre-EIS Market levels, though the specific transactions were not compared, indicating that the EIS Market is being treated by Market Participants as an alternative, not a replacement, for business transactions.