# THE EMPIRE DISTRICT ELECTRIC COMPANY

# INTERIM REPORT IN ACCORDANCE WITH STIPULATION & AGREEMENTS

## FEBRUARY 3, 2012

SERVICES YOU COUNT ON

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# INTERIM REPORT REGARDING CONTINUED PARTICIPATION IN SOUTHWEST POWER POOL

## SECTION 1: EXECUTIVE SUMMARY

The Empire District Electric Company (EDE) received approval from the Missouri Public Service Commission (MPSC) to participate in Southwest Power Pool's Regional Transmission Organization in MPSC Case Nos. EO-2006-0141. The docket was resolved through approval by the MPSC of stipulations. The stipulations provide for participation in Southwest Power Pool (SPP) during an "Interim Period" that terminates effective February 1, 2014. Two years prior to the termination of this Interim Period, the company is 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." On a historical basis, EDE estimates that its total company 2007 through 2010 (4 year) net savings or trade benefits was approximately $21.6 million. The 2010 total company net savings was approximately $2.4 million of which $2 million would be attributable to Missouri retail jurisdictional customers.

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." The companies conducted such a collaborative process with the MPSC Staff and Public Counsel in late 2011 and jointly developed an analysis plan for the Interim Report that was agreeable to the 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.

A forward looking benefit-cost analysis was developed using a combination of existing benefit-cost studies to estimate 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 EDE 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 B with the results presented below in Table 1. The tables show the net benefits (costs) associated with the EDE operating in SPP as compared to operating on a stand-alone basis. To the extent feasible, the results were framed as the annual net benefits 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, referred to as the Integrated Marketplace.The projected average annual net benefits of participating in SPP are approximately $12.2 million per year for the 2014 through 2017 study period. 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, higher transmission rates, price risk, and transaction costs associated with the RTO boundary. The following sections address each of the analysis categories. A summary of the analysis is presented in Attachment B.

## SECTION 2: <u>RELIABILITY SERVICES ANALYSIS</u>

For purposes of this report, Reliability Services consist of reliability coordination, Tariff Administration, OASIS Administration, ATC/AFC/TTC Calculations, Scheduling Agent, and Regional Transmission Planning. The estimated value of reliability coordination services is taken from existing studies.

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.[1] It would be very difficult for EDE to coordinate on a regional basis as a stand alone utility in the same manner as performed by SPP through its process and cooperation of its members. For EDE to provide similar services in a reduced scope where EDE independently performs calculations and studies currently provided by SPP staff and coordinates with other entities in the region would require additional resources to dedicate to these tasks. EDE's estimated incremental costs to provide these basic functions in the stand alone case are approximately $65,000 per year.[2] EDE believes the estimated annual cost of transmission service to meet EDE reserve sharing support for the stand alone vs. RTO case is insignificant.

## 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 SERVICES MARKET STUDIES

On July 27, 2005, CRA provided a study of the EIS Market for SPP. A copy of this study is Attachment D 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.[3] CRA concluded a 10 year present value of $47.9 million benefit of the EIS market for EDE.[4]

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[1] 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.

[2] Attachment D Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005 Appendix 4-3 Table 2 page AII-29

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

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

## 3.2 COMPANY STUDY OF ENERGY IMBALANCE SERVICE MARKET

The Stipulation and Agreement for MPSC Case Nos. EO-2006-0141 ("Stipulation") requires EDE to file this Report documenting the benefits of participation in the SPP EIS Market over a recent twelve (12) month period. The company study covered the scope detailed in the Stipulations by looking at a recent 12-month period defined as calendar year 2010 as well as analyzed the EIS trade benefits for the first three years 2007-2009 of the SPP EIS market.

### 3.2.1 SCOPE OF COMPANY STUDY

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

> Two (2) years prior to the conclusion of the Interim Period, Empire 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 Empire's continued participation in SPP.

#### 3.2.1.1 INTERIM REPORT – BENEFIT/COST ANALYSIS

The Stipulation further describes the Interim Report that is to accompany the final pleading in the footnotes. Quoting Footnote 1 of the agreement:

> What is contemplated in this Interim Report is that the actual (modeled) production costs for Empire 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.

#### 3.2.1.2 SCOPE OF COMPANY BENEFIT/COST ANALYSIS

The benefit/cost analysis attempts to compare Empire's actual operational results as a SPP member and EIS Market participant with a model simulation of estimated stand-alone results without the EIS Market.

The aactual operational case is Empire's actual results for the test period, which includes participation in the existing SPP EIS market. The Stand-alone without the EIS Market case simulates the company fleet using actual input values i.e. identical to the aactual operational case, but without any representation of interactions with the EIS Market. These actual model inputs included fuel prices, generating unit outages and new units coming online. Additionally, *hourly* actual values were input for system load, wind farm output profiles and bilateral purchases and sales of energy. This hypothetical simulation was conducted using PROSYM, the production costing model that EDE uses for fuel and purchase power budgeting. The model output provides an estimate of the production cost for the test period. The test period of the model is the 2010 calendar year to meet the requirement that the report cover a recent twelve month period.

Actual operating parameters were used in both cases. The analysis consisted of two separate cases with participation in the EIS Market being the only significant difference in assumptions. The comparison of these cases highlights the benefit of market participation through reduced production costs.
In addition to the estimate of production cost savings discussed above, Attachment C includes a comparison of other cost/benefit factors from the CRA Study estimates versus Empire actual charges related to SPP membership and participation in the EIS Market. These factors include FERC/NERC Fees, SPP Administration Fees and EIS Market Implementation costs. This historical analysis and results are identical to the those submitted to the Arkansas Public Service Commission pursuant to Order 9 in Docket No. 04-137-U on June 29, 2010 and June, 1 2011.

### **3.2.2 DESCRIPTION OF PROSYM MODEL**

PROSYM is a complete electric utility analysis system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour investigation of the operations of electric utilities.

Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. Empire has utilized PROSYM for planning and for fuel and purchase power budgeting for several years.

### 3.2.3 RESULTS OF COMPANY STUDY

This study estimates that the total company net trade/benefit from participating in the EIS market in 2010 was $2.4 million. The Missouri jurisdictional allocation is approximately $2 million for 2010. Of the total company estimate, $0.8 million is from reduced production costs due to participation in the EIS Market.

Empire estimates that, on a total company basis, a net benefit of $21.6 million has been realized over the four years (2007-2010) of participation in the EIS Market as an SPP member. Such benefits would have been primarily in the form of fuel and energy cost decreases, which would have passed through the Fuel Adjustment Clause (“FAC”) to Empire’s customers via a reduced FAC charge. However SPP Schedule 1A and other RTO costs are recovered through a formal rate adjustment process.

## 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 G. 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 EDE. 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[5] are summarized below in Table 5.

Table 5: Ventyx Study - Case IIA Summary

| Gross Benefits ($M) | SPP Subtotal | Unallocated Congestion | SPP Gross Benefit | EDE |
|---|---|---|---|---|
| **2014** | $209 | $(73.00) | $136.00 | $12.00 |
| **2015** | $201 | $(64.00) | $137.00 | $14.00 |
| **2016** | $232 | $(79.00) | $153.00 | $18.00 |
| **Average 2014-2016** | **$214** | **$(72.00)** | **$142.00** | **$14.67** |
| **2017** | | | | **$14.67** |

The gross benefit values EDE and SPP (based on Table 4-13 of the Ventyx study) are shown in the table above. The average gross benefit for EDE is utilized in the overall benefits and cost summary as shown on the Attachment B. For 2017, EDE simply used the average gross benefit for 2014-2016; however believe this to be conservative as an increase in gross benefit is anticipated once additional SPP regional transmission projects are placed in service in 2017. Also, the EDE value is reduced by a prorated share of unallocated congestion from Table 4-13 of the Ventyx study as shown on the Future Markets line of Attachment B. The unallocated congestion deduction may well be mitigated (overstated) through the Integrated Marketplace issuances of Transmission Congestion Rights (TCRs) to EDE and congestion risk management practices.

## 3.4 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 estimates of this potential cost savings. The savings largely result from a reduced workforce level required by individual balancing authorities and reduced regulation for load

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

requirements. The Steering Committee Executive Summary is included with this document as Attachment H. Although the Steering Committee only reported results through 2011, savings to 2017 have been estimated by escalating costs by 2.5% annually for additional years and are shown on the Balancing Authority Consolidation line of Attachment B.

## 3.5 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:

### 3.5.1 COST TO IMPLEMENT FUTURE MARKETS

Current capital cost estimates of $1 million 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, using a 10% interest rate, the costs equal approximately $$187,000 per year during the study period. It is estimated that $0.5 million in capital costs will be needed to interface with SPP and MISO markets if EDE is a stand-alone entity but desires to participate in these markets with resource bids/offers. This estimated cost is not included since it is optional as a stand alone entity to participate. The on-going expenses associated with new market systems and approximately six new full-time positions are about $1 million per year starting in 2014. Total estimated costs to implement integrated markets are shown in the Power Market Operations of Attachment B.

### 3.5.2 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 EDE transmission systems.

Current estimated incremental annual costs of point-to-point transmission service to deliver energy from existing network resources to load are $9.345 Million. These estimates result from the actual MW value of reserved firm transmission service for existing network resources outside the EDE transmission system and within SPP multiplied by the expected SPP firm point-to-point through and out transmission rates for the period being considered in this report. Since EDE's StateLine Combined Cycle unit is jointly owned with Westar Energy. It is presumed that in the Stand Alone case, EDE would receive approximately $3.12Million in annual transmission revenue to offset part of the $9.345 Million SPP costs for a net of $6.225 Million in net cost for Stand Alone operations or savings by continuing membership in SPP and are included on the Transmission Service-Existing Resources line of Attachment B.

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.

### 3.5.3 POSSIBLE IMPACTS INVOLVING EMPIRE'S PLUM POINT POWER STATION RESOURCE AS IT RELATES TO CONTINUED MEMBERSHIP IN SPP AND ENTERGY ARKANSAS, INC.'S POSSIBLE INTEGRATION INTO THE MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO) RTO.

EDE is a co-owner of the Plum Point Energy Station, a recently completed 665MW megawatt, coal-fired generating facility near Osceola, Arkansas, which entered commercial operation on September 1, 2010. EDE's 7.52% ownership interest entitles it to approximately 50 MW of Plum Point's capacity and associated energy. In addition, EDE entered into a long-term (30 year) purchased power agreement for an additional 7.5% of Plum Point capacity, with the option to purchase an undivided ownership interest in 2015 in the approximately 50 MW amount covered by the purchased power agreement. EDE's entitlements to Plum Point are base-load Designated Network Resources for EDE under the SPP Open Access Transmission Tariff. Since Plum Point is physically located on Entergy Arkansas's transmission system, Empire procured long term (20 years) point to point transmission service from Entergy Services, Inc. The transmission service agreement (TSA) was entered into in August 2006 and accepted by FERC in Docket Number ER06-1436. Transmission service pricing for this firm transmission service is based on the FERC accepted Schedule 7 of Entergy Services Open Access Transmission Tariff, which is currently approximately $18.48/kW-year or $1.848MM per year. It is our understanding from both Entergy Services, Inc. and MISO representatives that Empire's transmission service for Plum Point would be immediately converted to MISO's Schedule 7 through and out transmission service, which is currently $31.03/kW-year or $3.103MM, for an increase of approximately $1.26MM plus any additional MISO market related charges.

In addition, Plum Point is located in the PLUM Balancing Authority Area within the Entergy Arkansas transmission service area. Balancing Authority services for PLUM are provided by Constellation Energy Control and Dispatch, LLC ("CECD"). It is possible that the PLUM Balancing Authority would be consolidated (continuation of the PLUM BA may be a higher cost option) with the MISO Balancing Authority and be subject to MISO's scheduling and congestion provisions, which are expected to be higher than Entergy Services for delivery of receipts of capacity and energy from PLUM to Empire.

Currently, a substantive dispute exists between SPP and MISO related to the Joint Operating Agreement that affects Missouri utilities, including EDE. SPP and the SPP members believe that MISO must be willing to amend the JOA to include other fundamental improvements in connection with the negotiation of market-to-market re-dispatch terms. In order for the parties to effectuate the most optimal and accurate market-to-market re-dispatch process, the parties must first: (1) address and improve the existing flowgate allocation methodology applicable when non-reciprocal entities join the CMP (as MISO has committed to do in previous discussions); and, (2) resolve the current market flow calculation dispute. These two foundational issues must first be resolved before a market-to-market redispatch process can be negotiated and implemented because both items materially impact the performance and precision of any such process. The current flowgate allocation methodology does not account for all negative impacts to SPP, including Missouri utilities. This will be exacerbated in the event Entergy integrates into MISO.

# SECTION 4: TRANSMISSION FACILITY UPGRADE ANALYSIS

## 4.1 BENEFIT AND COST OF SPP PROJECTS

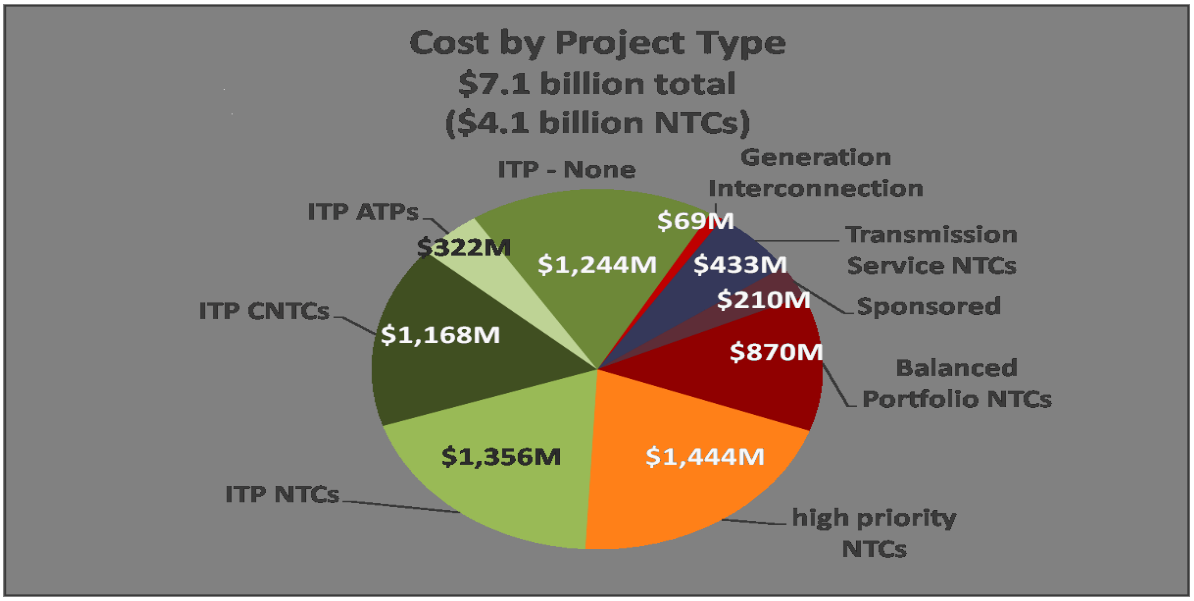
The work performed by the Regional State Committee's Rate Impact Task Force (RITF) serves as a key component of this analysis because it reflects projected costs of projects in the 2010 SPP Transmission Expansion Plan (SPP Board approved in early 2011).

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.

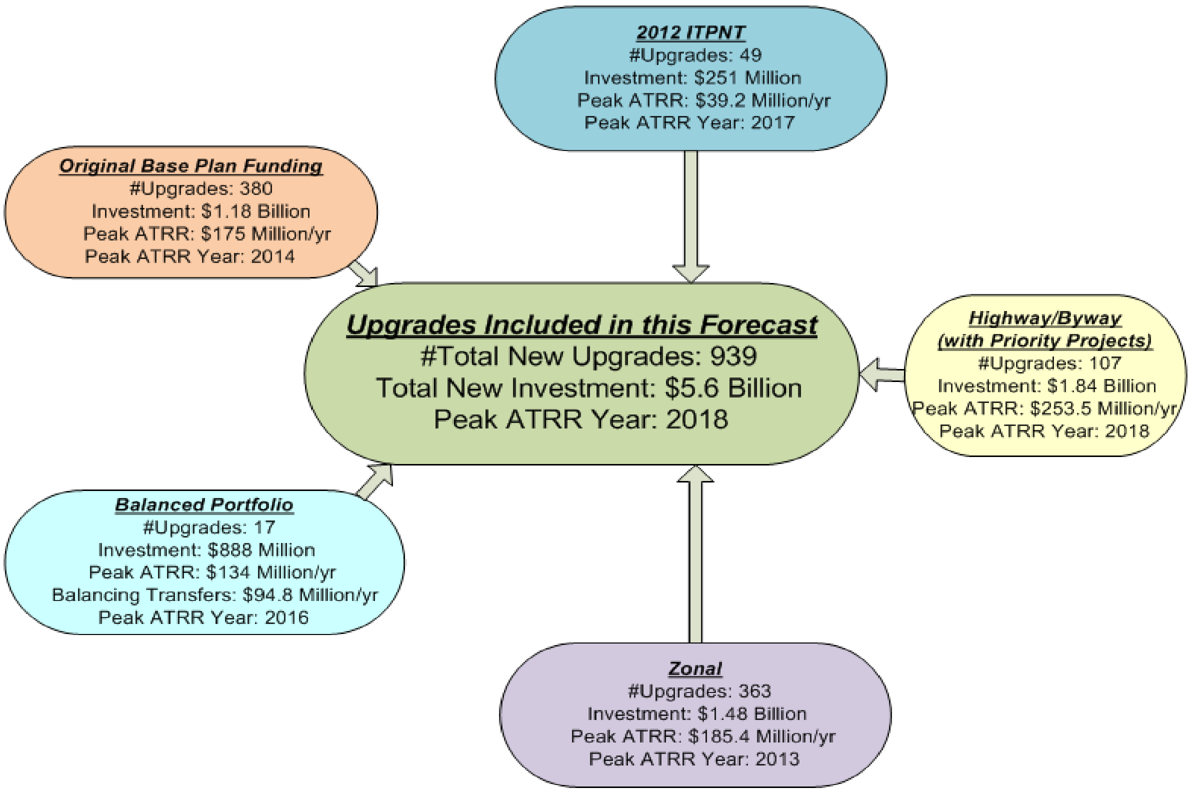
Included as Attachment F is the SPP ATRR Forecast Report to the SPP Regional Tariff Working Group and the SPP Regional State Committee, January 2012. This information was used to estimate EDE's average annual regional transmission allocation expense of $8.116 Million over the 4 year study period as stated in Attachment B. The analysis includes SPP's implementation of the Balanced Portfolio transfer credits that would be applicable to EDE as a benefit deficient zone beginning in 2012 through 2021.

On January 31, 2012, the SPP BOD approved the 2012 SPP Transmission Expansion Plan (STEP) which includes $7.1Billion (Figure 2012) in transmission projects that are under construction, noticed for construction, or planned for construction.




EDE hopes to obtain 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 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.

Annual benefits to EDE 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. EDE has taken a conservative approach for the inclusion of these project set benefits ($0). As an example, gas price impacts, originally included in the Priority Project benefit totals, are excluded from the benefit calculations for EDE. As of January 14, 2012, below are the transmission upgrades approved by SPP with approximated annual transmission revenue requirements (ATRR). Regional transmission benefits that are realized by EDE will most likely be in the form of reduced energy/wholesale energy costs or increased sales margins that will flow through to the customer in a timely manner, whereas the actual SPP allocation of regional and zonal costs (Schedule 11) and RTO administrative fees (Schedule 1A) will be recoverable through a future general rate case in Missouri. In Arkansas and Oklahoma, the Commissions have approved and implemented SPP transmission recovery riders for the jurisdictional SPP members, including EDE.




Attachment F 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.

**SECTION 5 SPP EXIT FEE 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 portion of estimated withdrawal obligations attributable to EDE as of June 1, 2011 was $4.5 Million. SPP’s projected EDE withdrawal obligation for February 1, 2014 is estimated to be $6.8 Million assuming the current withdrawal obligation method of determination remains unchanged. However, it appears the SPP will be filing at the FERC in 2012 for a change in withdrawal obligation methodology that would also include financial obligation related to regional transmission project long term allocations. Based on an SPP estimate of such SPP Open Access Tariff Schedule 11 cost allocation liabilities to EDE for regional projects approved to date, including the SPP 2012 STEP Near Term Projects, EDE’s withdrawal obligation would be approximately $148Million ($6.8 Million plus $141MM (payable over a 10 year period)) in transmission allocation obligation. As previously mentioned the SPP has not finalized its change in withdrawal obligation policy and plan to obtain SPP BOD approval in 2012 with implementation in late 2012/2013.

**SECTION 6 ADMINISTRATIVE COST ANALYSIS**

On a stand-alone basis, EDE 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 EDE to maintain and operate as a stand-alone transmission provider.  One aspect that is not quantified in estimates is the potential for EDE 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 2005 CRA study estimated administrative costs for EDE in Appendix 4-3, Table 2[6], which shows the EDE projected annual stand-alone administrative costs with a 10-year present value of $5,079,000. This amortized at a discount rate of 10% equals $827,000 per year.  The study also shows additional-present value standalone costs of $707,000.  This amortized at a discount rate of 10% equals $115,000 per year. The value above is utilized in the overall benefits and cost summary as shown on the Administrative Costs line of Attachment B.

SPP's current administrative cost/Schedule 1A is $0.255 cents/MWH of total load requirements for 2012.  SPP's latest projections for Schedule 1A for the 4 year study period are $0.28/MWH (2014), $0.335/MWH (2015), $0.337/MWH (2016), and $0.338/MWH (2017).

## 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 company 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.  Although projecting the effects

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

of these elements presents additional challenges, the potential impacts are very substantial and should be considered in evaluating the overall benefit-cost results and the complete SPP value proposition over the long term.

## 7.1 REGIONAL 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, including an EDE representative. The scope and objective of these efforts was 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. EDE expects 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 and future ITP projects approved for construction.

The SPP RSC and BOD unanimously approved the recommendations as to how SPP should conduct the Regional Cost Allocation Review. This included a recommendation of applying ten principles as a guide to conducting the review. These principles include: simplicity; acknowledgment of the “roughly commensurate” legal standard; equity over time; the use of best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects. Applying these principles the RARTF recommended and the SPP MOPC, RSC, and BOD approved that the  review would contain two evaluations; (1) as required by SPP's OATT, the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a Notification to Construct (NTC) has been issued since June 2010 and (2) the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a NTC has been issued since June 2010 plus Board approved transmission projects that have received an Authorization to Plan (ATP) with in-service dates of ten years or less.

The RCA review will apply a 0.75 weighting for ATP projects due to the less certain nature of these projects as well as their costs and benefits. The review be integrated with the 10 Year ITP Plan schedule and be undertaken after its completion. The review will use the aggregate value of dollars for all projects studied under the SPPHighway/Byway cost allocation methodology in dollars current to the year the review is conducted. To remain consistent with SPP's OATT, the review will use a 40-year horizon to evaluate all transmission projects. The information used in the review be the most up to date and that all assumptions be vetted through SPP's stakeholder process. Through the work of the Economic Studies Working Group (ESWG) certain benefits will be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits.  Additionally, the Report contains a recommendation regarding the establishment of a Benefit to Cost (B/C) threshold. The recommended B/C) threshold would be the basis for SPP staff and stakeholders to evaluate remedies for any zone falling below the threshold. Specifically, the Report recommends that:  a threshold be set at a B/C ratio of 0.8. With this benchmark, if the review shows that any zones fall below this threshold; SPP Staff will study and report on potential remedies for these zones.

A list of recommended mitigation remedies was also approved for SPP staff to study and report on for any zone below the 0.8 threshold. The recommended list of remedies in preferential order includes, but is not limited to: (1) acceleration of planned upgrades; (2) issuance of new upgrades; (3) applying highway funding to one or more byway projects; (4) applying highway funding to one or more seams projects; (5) zonal transfers (similar to balanced portfolio transfers) to offset costs or a lack of benefits to a zone; (6) exemptions for cost associated with the next set of projects; and (7) changes to cost allocation percentage. Since EDE was a benefit deficit zone for the balanced portfolio, priority projects, and ITP10 projects, EDE believes this policy of cost allocation impacts and implementation of remedies to improve EDE's benefit/cost for regionally funded and allocated projects is vitally important to maintain and grow benefits related to SPP membership.

## 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 EDE if the company operates 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 EDE 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 company. 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 company anticipates 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 impacting 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 integrated marketplace 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**.** Whereas, under the RTO, non-firm network service is utilized to make economical purchases from any source within the entire SPP region there would be an additional charge equal to the through and out rate for SPP added to the cost of these transactions. As an estimate for a typical year, EDE imports approximately 300,000 - 500,000 MWHrs of economy energy. If one applies an additional transmission charge of $4/MWH for imported energy, this would equal to an additional annual costs of $1.2Million to $2 Million or cause such transactions to be replaced by internal EDE generation. For 2014-2017 projections were made that 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 EDE as an entity 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).

EDE is not a large exporter of wholesale energy today and as a stand alone entity future sales would be further reduced due to increased wheeling costs for exports.

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 in regard to purchase power than the impact from lost sales  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, a SPP member 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 ENVIRONMENTAL LAW AND REGULATION CONSIDERATION

On August 30, 2011, the Commission opened Case Number EW-2012-0065 to investigate the cost of complying with federal environmental regulations.  EDE plans to actively participate in the process as the Staff works toward submitting its  findings and recommendations to the Commission on May 1, 2012.

The public policy initiatives related to state and federal renewable energy standards and governmental regulation of emissions, environmental impacts, and public health could affect the future of long-term transmission planning.  For instance, in June 2010, the Environmental Protection Agency (EPA) announced an emissions standard that will impact coal-fired electric generation facilities. Under this new standard, emissions from power plants and other industrial facilities will be required to meet a new "1-hour standard" designed to reduce short term exposure to Sulfur Dioxide (SO2). Additionally in 2010, the EPA opened rulemaking dockets to develop and implement standards to reduce the transfer of SO2 and nitrogen oxide (NOx) through the air and to regulate coal-ash, which is a by-product of traditional electric generation processes. These proposed rules, once implemented, will have an associated compliance cost that will be borne by industry participants and ratepayers.  SPP is keenly aware and supportive of our efforts to respond to and defend such policies that could adversely affect our customers. In 2011, SPP sent two letters to the EPA regarding the pending regulations. SPP expressed its and its members concerns regarding the multiple pending regulations. The regulations of concern that the letter addressed include: the Clean Air Transport Rule, now finalized as the Cross-State Air Pollution Rule (CSAPR); the Coal Combustion Residuals Rule; revisions to section 316(b) of the Clean Water Act; and the Hazardous Air Pollutants changes for the regulation of mercury emissions from electricity generation units.

The finalized CSAPR utilized the EPA‟s Integrated Planning Model (IPM), and a review by SPP found the model did not dispatch several key generators in the SPP footprint. The removal of those generators from the SPP region could cause major reliability issues in SPP‟s current summer peak load flow models. SPP sent a letter regarding these issues to the EPA on September 20, 2011. The reliability issues included N-1 contingency violations totaling 1047 circumstances where voltage was 90% of nominal on 167 different buses and 220 cases where line ratings exceeded the 100% applicable emergency rating.

An even clearer representation of reliability violations was found by applying higher operability limits of 120% to the overloads, in which there were 16 such overloads on the system. Using a similar out of normal range, there were 93 circumstances where voltage dropped below 85% of nominal. These “clear-cut” examples of reliability standards violations represent well-founded concerns regarding the timeline with which the CSAPR would be instituted. In addition to these issues, there were 11 reliability cases that could not be solved in SPP‟s models. Such violations are clearly indicative of the EPA IPM‟s failure to account for reliability standard thresholds that SPP is required to maintain in accordance with Federal Energy Regulatory Commission approved standards. Through SPP’s leadership, EDE and other members are currently evaluating operational impacts due to compliance for 2013, 2014 and 2015.

There is no doubt that compliance implementation of these environmental requirements will affect operations and costs to our customers, however we do believe that the planned transmission expansion in the SPP and potential transmission expansion in the Southwest Missouri area will enable EDE to mitigate some of the negative impacts of such laws and requirements.

**Benefit-Cost Analysis Scope for the Interim Report for
The Empire District Electric Company
Participation in the Southwest Power Pool**

The Empire District Electric Company (Empire) proposes to implement the following approach in order to address the requirements of the current SPP membership stipulation (Case No. EO-2006-0141) in collaboration with the Missouri Public Service Commission Staff and Office of Public Council:

Develop a benefit-cost analysis with a scope beyond a historical analysis of the Energy Imbalance Service (EIS) market based on:

1) An evaluation of estimated net savings or benefits that have accrued to Empire retail customers during the first three years of the Southwest Power Pool ("SPP") Energy Imbalance Services ("EIS") market that was completed and submitted to the Arkansas Public Service Commission (APSC) on or about June 1, 2011 in Docket No. 04-137-U. Future related submittals to the APSC will also be provided to the MOPSC and stakeholders.
2) Structure the analysis to include a broad array of factors that impact the benefits and costs associated with SPP participation.
3) Control the cost of the analysis by using existing studies where available, participate in and submit to the MOPSC any future SPP related studies or updates, and develop estimates internally, where necessary, for the remaining components of the analysis.

This methodology not only broadens the required analysis, but also enables Empire to avoid the cost associated with the performance of special third party consultant studies. In addition, it will allow the use of information specific to Empire, where helpful and practical.

The following are the basic elements associated with Empire's analysis of the estimated 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

SPP Exit Fees

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

Plum Point Power Station RTO Related Issues

The above factors will be analyzed from an SPP membership perspective and an Empire stand-alone case. The benefits and costs of these elements will be accumulated for the SPP case and for the stand-alone case to create a total value comparison of each alternative.
Where needed, a range of values will be used to reflect the significant uncertainty behind the estimates. The time horizon of the historical analysis will be for 2007 through 2010 and from a forward perspective using 2014 through 2017 to capture the expected completion of the SPP Priority Projects.

Reliability Services Analysis
The estimated value of reliability coordination services can be taken from existing studies of these services and supplemented with Empire specific information, as 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
1) 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 in February 2007, 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. The Boston Pacific post implementation review produced results on a regional basis only. However, this study had the advantages of being 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 provided by Empire to estimate system production costs both with and without the EIS market based on estimated net savings or benefits that have accrued to Missouri ratepayers during the first three years of the Southwest Power Pool ("SPP") Energy Imbalance Services ("EIS") market that was completed and submitted to the Arkansas Public Service Commission on or about June 1, 2010 in Docket No. 04-137-U. This study will cover the scope detailed in the Stipulation and Agreement by analyzing a recent 12-month period.

2) 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/volatility. The Ventyx study results are available for Empire, and any future SPP developed sensitivity analysis related to gas prices will be provided to the MOPSC and stakeholders. 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.

3) The SPP consolidated balancing authority (CBA) 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 Empire's analysis.

<u>Other Energy Market Factors</u>

In addition to the existing market operations studies, other factors need to be considered to provide a valid comparison between the SPP case and the stand-alone case:

A. 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 include additional administrative costs to manage interfaces between the companies and multiple RTO markets and 3rd party transmission providers;

B. 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 Empire transmission system. These costs will be added to the stand-alone case to the extent they are not already incorporated in the EIS study; and,

C. Transmission service priority can have a material impact on market operations. Potential counterparties are less likely to enter into transactions with Empire 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.

D. Possible impacts involving Empire's Plum Point Power Station resource as it relates to continued membership in SPP and Entergy Arkansas, Inc.'s possible integration into the Midwest Independent System Operator (MISO) RTO.

Transmission Upgrades Analysis

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 Empire 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.

A key uncertainty in this area is whether and how cost impacts may be shifted or mitigated as a result of the policy provisions in the SPP Tariff, Attachment J, Section III.D (entitled "Review of Base Plan Allocation Methodology"). This important initiative is well underway within the SPP stakeholder process by Regional Allocation Review Task Force (RARTF) and relates to the development of the cost allocation reasonableness review method and possible remedies for long term member fairness and equity considerations. This key policy development effort may be documented as an important non-quantified factor in the analysis.

SPP Exit Fees Analysis

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.

Administrative Costs Analysis

Projections of the fees under SPP Schedule 1-A will be compared to estimates of the costs that will be incurred by Empire if it is required to provide 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 forums will be reviewed, such as those in the SPP study by CRA and SPP finance and Board of Director meetings.

Factors Not Explicitly Quantified

Not all factors that have a bearing on the benefits and costs of RTO participation may be readily quantifiable. Where such factors are identified (such as the pending work of the RARTF and possible RTO related impacts of compliance with Environmental Protection Agency rules and regulations), but not included in the numeric analysis, will be identified as additional considerations with an indication of the potential impact and direction in which the results likely would be affected.

Schedule BKW-1

Attachment B

Highly Confidential in its Entirety

Schedule BKW-1
Attachment C

Historical - Attachment C

= Data Input Areas

All dollars are in thousands

| Line No | Positive numbers represent benefits of remaining members of SPP | | 2007 | 2008 | 2009 | Cumulative 3 Years | 2010 | Cumulative 4 Years |
|---|---|---|---|---|---|---|---|---|
| | **From CRA Study** | | | | | | | |
| | **Stand Alone Cost** | | | | | | | |
| 1 | Cost to Provide SPP Functions | | (821) | (824) | (721) | | (737) | |
| 2 | FERC Fees | | (51) | (51) | (51) | | (51) | |
| 3 | Old NERC | | - | - | - | | - | |
| 4 | NERC Fees | | (117) | (159) | (232) | | (243) | |
| 5 | Stand Alone Cost Annual Subtotal<br>Sum L1 -L4 | | (989) | (1,034) | (1,004) | | (1,031) | |
| | **EIS Cost** | | | | | | | |
| 6 | SPP Implementation Charges | | (680) | (680) | (541) | | (547) | |
| 7 | Participant IE Implementation Cost | | (1,091) | (1,106) | (1,122) | | (1,138) | |
| 8 | FERC Fees | | (208) | (208) | (208) | | (208) | |
| 9 | NERC Fees | | (117) | (159) | (232) | | (243) | |
| 10 | EIS Cost Annual Subtotal<br>Sum L6 - L9 | | (2,096) | (2,153) | (2,103) | | (2,136) | |
| | **CRA Trade Benefits** | | | | | | | |
| 11 | Stand Alone to Base Benefits | | (866) | (644) | (413) | | (170) | |
| 12 | Base to EIS Benefits | | 8,881 | 9,105 | 9,334 | | 9,569 | |
| 13 | CRA Annual Trade Benefits<br>- L11 + L12 | | 9,747 | 9,749 | 9,747 | | 9,739 | |
| | **CRA Wheeling Benefits by Remaining a member of SPP** | | | | | | | |
| 14 | Wheeling Charges | | (6,588) | (6,419) | (6,238) | | (6,045) | |
| 15 | Wheeling Revenues | | 2,617 | 2,738 | 2,864 | | 2,995 | |
| 16 | Transmission Construction Cost | | (70) | (106) | (141) | | (176) | |
| 17 | CRA Wheeling Benefits Annual Subtotal<br>Sum L14 - L16 | | (4,041) | (3,787) | (3,515) | | (3,226) | |
| | **Current State Actual Cost** | | 2007 | 2008 | 2009 | | 2010 | |
| 18 | **Current Costs** | | | | | | | |
| 19 | SPP Admin-Sched 1A | | 1,550 | 1,530 | 1,413 | | 1,551 | |
| 20 | Participant IE Implementation Cost | | 506 | 123 | 126 | | 130 | |
| 21 | FERC Fees | | 221 | 209 | 280 | | 369 | |
| 22 | NERC Fees | | 117 | 159 | 232 | | 243 | |
| 23 | Current State Actual Cost Subtotal<br>Sum L19 - L22 | | 2,394 | 2,021 | 2,051 | | 2,293 | |
| | **Projected Trade Benefits** | | | | | | | |
| 24 | Estimated Stand Alone Production Cost | | 193,851 | 214,749 | 179,665 | **$588,265** | 186,798 | **$775,063** |
| 25 | Current State EIS Actual Cost | | 190,537 | 203,468 | 182,354 | **$576,359** | 185,981 | **$762,340** |
| | **Projected Trade Benefit Savings** | | 3,314 | 11,281 | (2,689) | **$11,906** | 817 | **$12,723** |
| | **Projected Savings** | | | | | | | |
| 26 | CRA Estimated Trade Benefits | + | 9,747 | 9,749 | 9,747 | | 9,739 | |
| 27 | EIS Cost Annual Subtotal | + | (2,096) | (2,153) | (2,103) | | (2,136) | |
| 28 | Stand Alone Cost Annual Subtotal | - | (989) | (1,034) | (1,004) | | (1,031) | |
| 29 | Wheeling Charges | + | 6,588 | 6,419 | 6,238 | | 6,045 | |
| 30 | Wheeling Revenues | + | (2,617) | (2,738) | (2,864) | | (2,995) | |
| 31 | Transmission Construction Cost | + | (70) | (106) | (141) | | (176) | |
| 32 | **Projected Annual Savings**<br>L26 - L31 | | **12,541** | 12,205 | 11,881 | **36,627** | 11,508 | **$48,135** |
| | **Actual Savings** | | | | | | | |
| 33 | Estimated Stand Alone Production Cost | + | 193,851 | 214,749 | 179,665 | | 186,798 | |
| 34 | Current State EIS Actual Cost | - | 190,537 | 203,468 | 182,354 | | 185,981 | |
| 35 | Current State Actual Cost Subtotal | + | (2,394) | (2,021) | (2,051) | | (2,293) | |
| 36 | Stand Alone Cost Annual Subtotal | - | (989) | (1,034) | (1,004) | | (1,031) | |
| 37 | Wheeling Charges | + | 6,588 | 6,419 | 6,238 | | 6,045 | |
| 38 | Wheeling Revenues | + | (2,617) | (2,738) | (2,864) | | (2,995) | |
| 39 | Transmission Construction Cost | + | (70) | (106) | (141) | | (176) | |
| 40 | **Annual Savings** | | **5,810** | **13,869** | **(503)** | **19,176** | **2,429** | **21,605** |
| 41 | **Missouri jurisdictional allocator (%)** | | 82.907% | 82.907% | 82.907% | | 82.907% | |
| 42 | **Missouri jurisdictional Benefit ($000)** | | **4,816.90** | **11,498.37** | **(417.02)** | **15,898.25** | **2,013.73** | **17,911.97** |

# Southwest Power Pool

## Cost-Benefit Analysis

## Performed for the SPP Regional State Committee

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

CHARLES RIVER ASSOCIATES

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## Revisions

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

# List of Abbreviations

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

# Executive Summary

## Background

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

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

## Methodology

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

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

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

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[1] The Southwestern Power Administration has formally withdrawn from the SPP, but will continue to participate in SPP through a contractual arrangement. In this study, the Southwestern Power Administration was treated as a full-member of SPP.
[2] The SPP RSC is a voluntary organization that may consist of one designated commissioner from each state regulatory commission with jurisdiction over one or more SPP members.

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

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

CRA modeled three operational market scenarios in this study:

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

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

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

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

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

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

## *Findings*

### EIS Case

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

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

[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)*

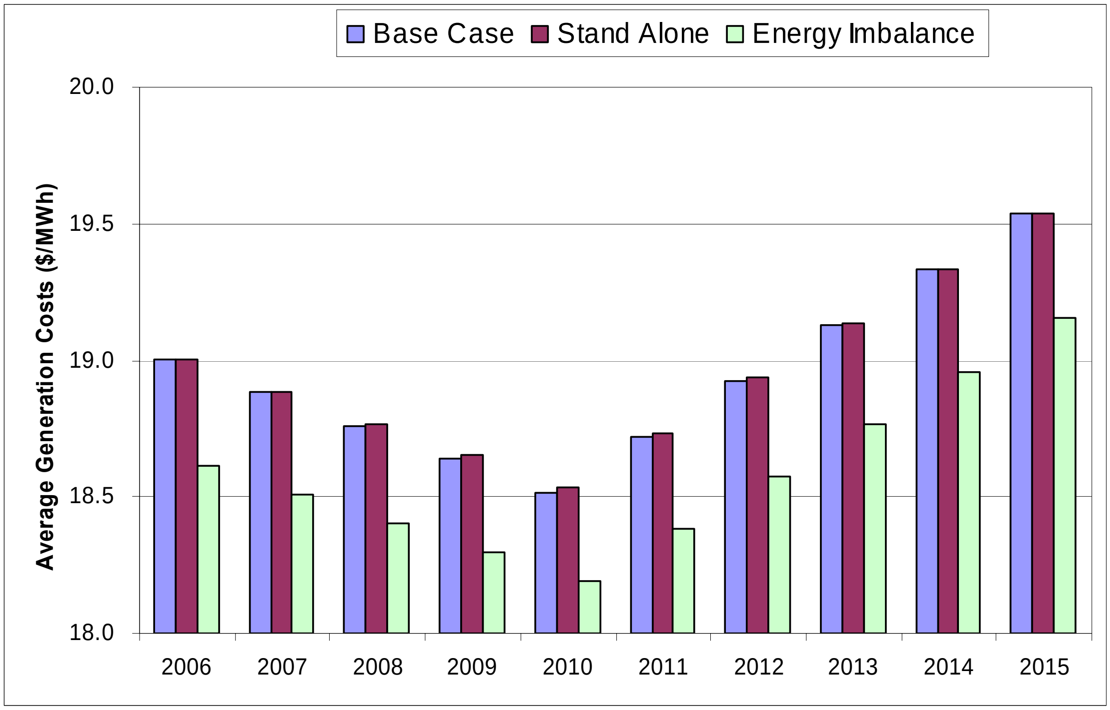
| | Benefits excl. Wheeling | Total Benefits |
|---|---|---|
| **Arkansas** | (3.0) | (5.0) |
| **Louisiana** | (2.6) | (3.0) |
| **Kansas** | (22.2) | 3.6 |
| **Missouri** | (13.7) | 2.7 |
| **New Mexico** | (0.7) | 5.9 |
| **Oklahoma** | (16.2) | (25.9) |
| **Texas** | (5.5) | 16.4 |

## 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.

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## 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.

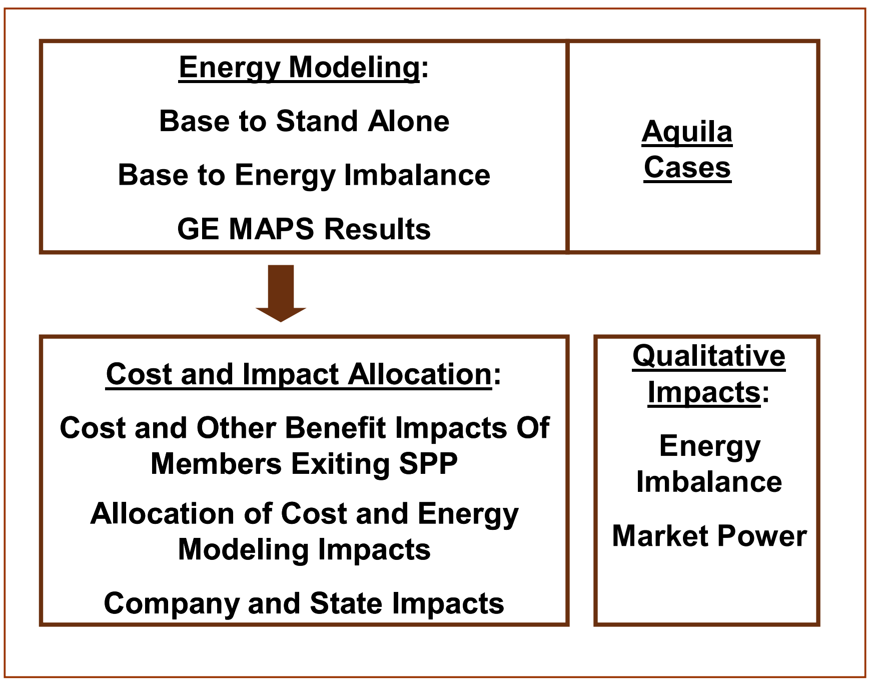
CRA presented status updates and detailed approaches throughout the study period. CRA and the CBTF members reviewed the results and refined the assumptions. This report presents the results of the modeling analyses and of the qualitative Cost-Benefit elements.

## *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.

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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.

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# 3 Wholesale Energy Modeling

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

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

### 3.1.1 Input Assumptions

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

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

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

[12] MAPS is the Multi-Area Production Simulation software developed by General Electric Power Systems and proprietary to GE.
[13] MAPS does not simulate the regulation market, nor does it reflect AC system constraints such as the reactive power needs of the system.
[14] Operating Reserves are needed to adjust for load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales. The SPP Reserve Sharing Program establishes minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group. The SPP Reserve Sharing Program assures that there are available at all times capacity resources that can be used quickly to relieve stress on the interconnected electric system during an Operating Reserve Contingency. According to the SPP reserve sharing criteria, pool-wide reserve requirements are set as the size of the largest contingency plus one-half of the second-largest contingency. These requirements are then allocated among control areas in proportion to peak demand.
[15] Cost does not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

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- 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.

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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.

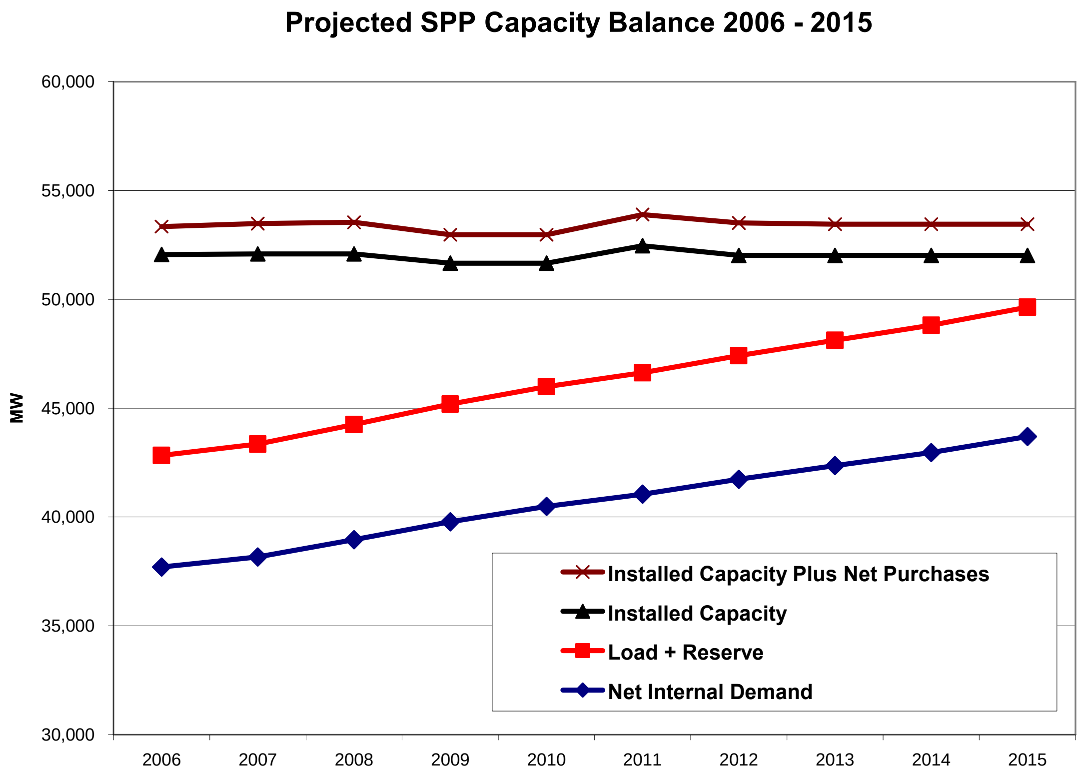
Note also that in each of modeling scenarios it is assumed that the entire volume of the market is cleared through the simulation's spot market. To the extent that transmission owners' self-dispatch and self-deployment is efficient and to the extent that the bilateral market is efficient, the results 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.

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### 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 |

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**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**

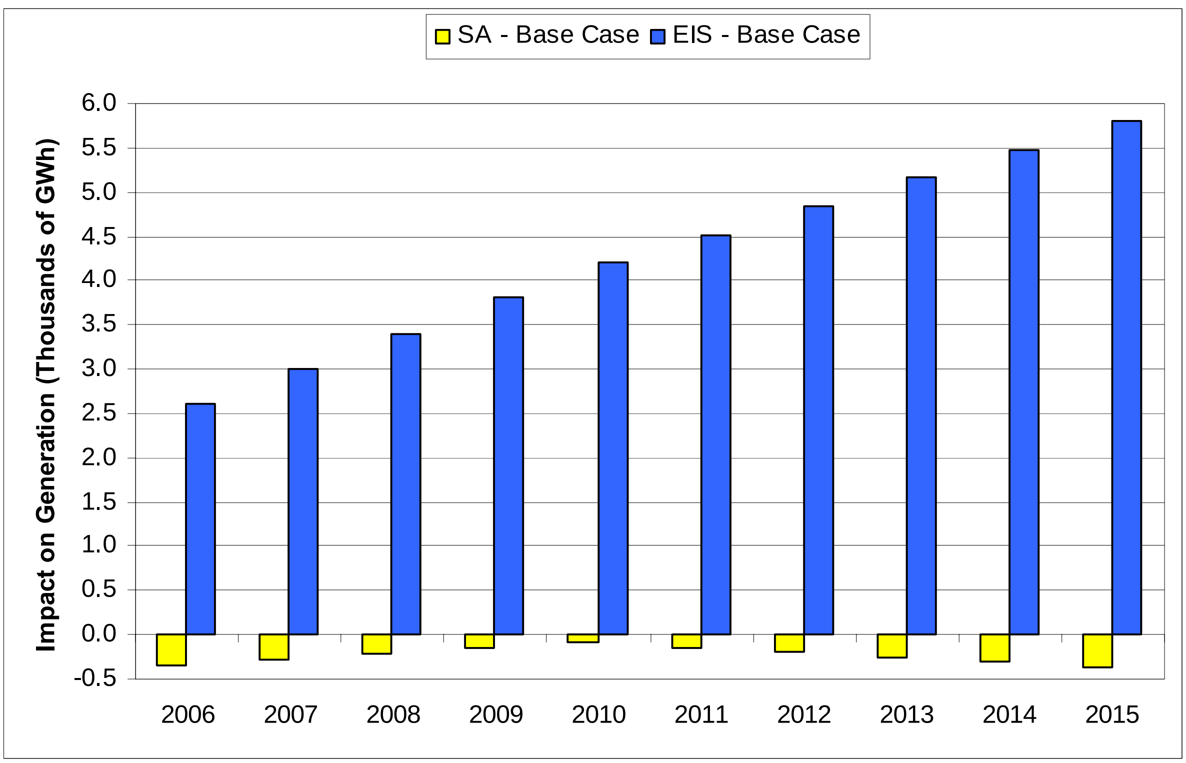
| Impact (SA – Base) | | | |
|---|---|---|---|
| Year | Generation (GWh) | NOx Emissions (T) | SOx Emissions (T) |
| 2006 | (350) | 113 | (6) |
| 2007 | (284) | 296 | 301 |
| 2008 | (217) | 480 | 608 |
| 2009 | (151) | 664 | 915 |
| 2010 | (85) | 848 | 1,222 |
| 2011 | (142) | 744 | 1,036 |
| 2012 | (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.

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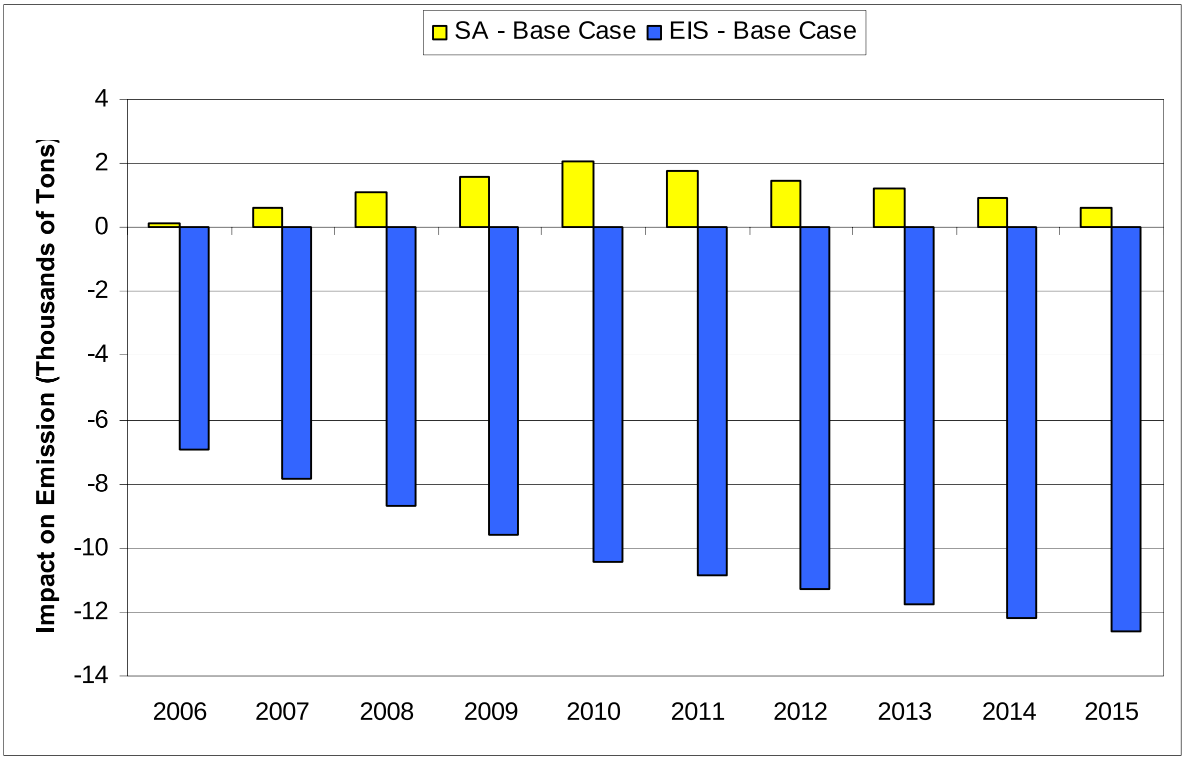
In the EIS, case, however, an opposite result occurs. The EIS case results in a marked increase in generation in the SPP region due to the increased efficiency of the SPP dispatch as a result of the improved operation of the flowgate constraints and the increased ability for non-network units to be dispatched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

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### 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**

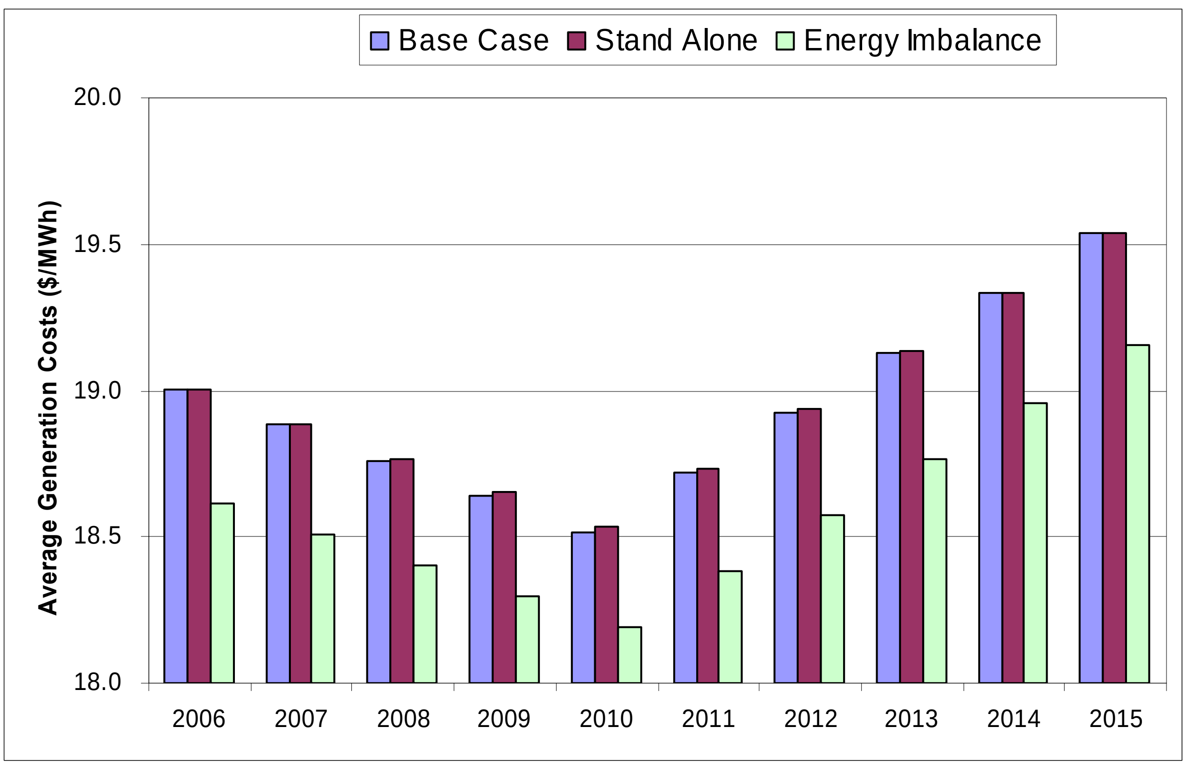
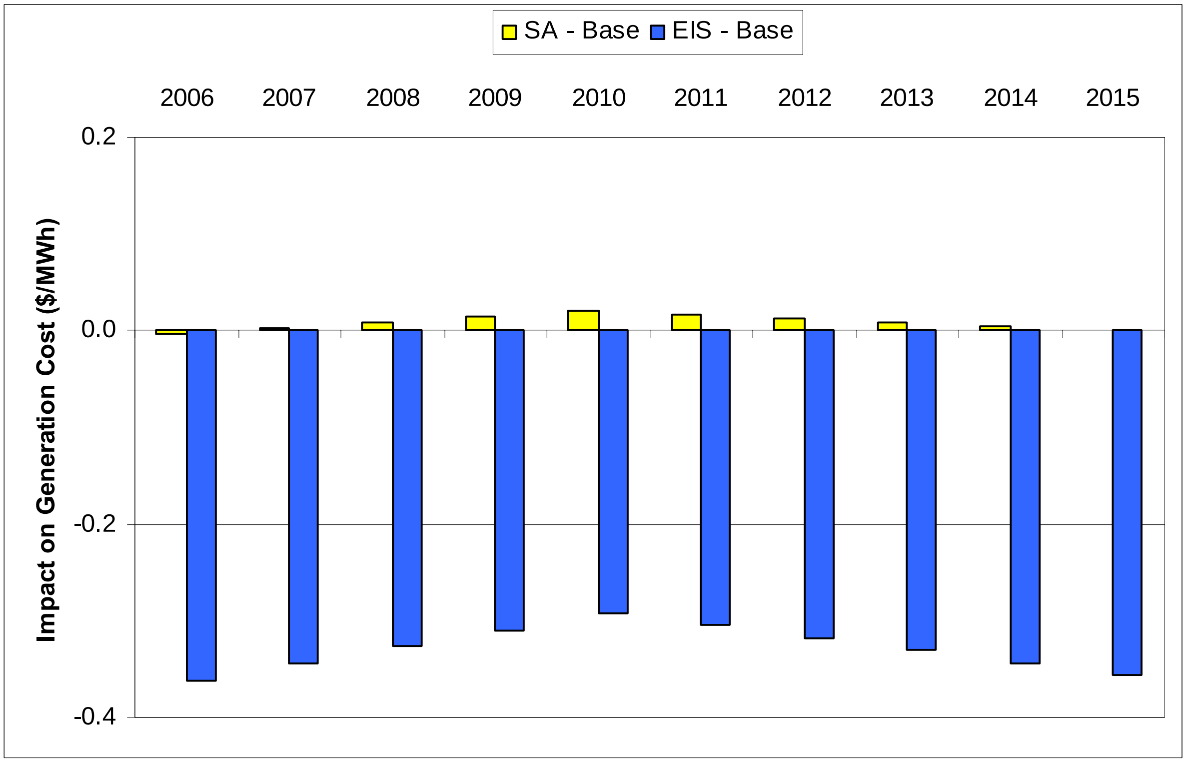


**Figure 3-5 SPP Generation Cost ($/MWh) Differences**




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 |

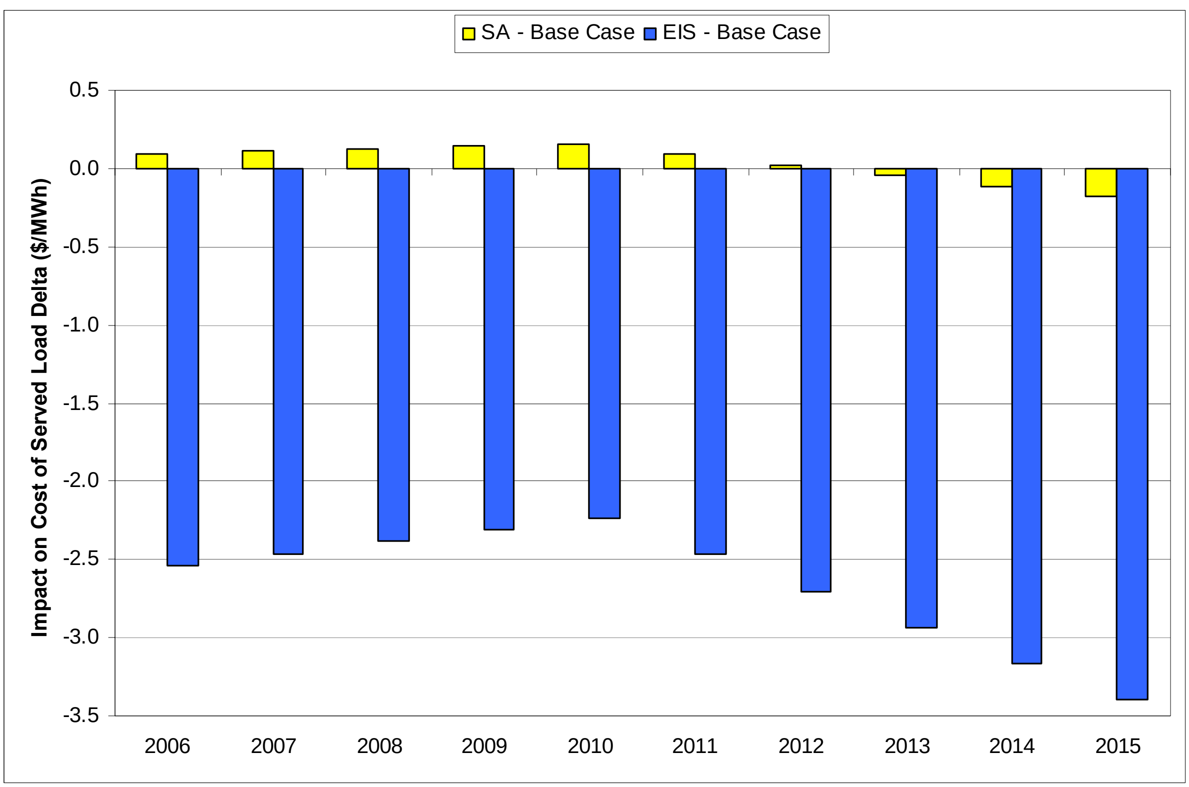
[26] The "spot price" refers to the locational price of energy (in $/MWh) as calculated under the locational marginal price (LMP) system, assuming cost-based, security constrained optimal dispatch of the system. While a spot price can be calculated for any point in the system, it is not generally reflective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

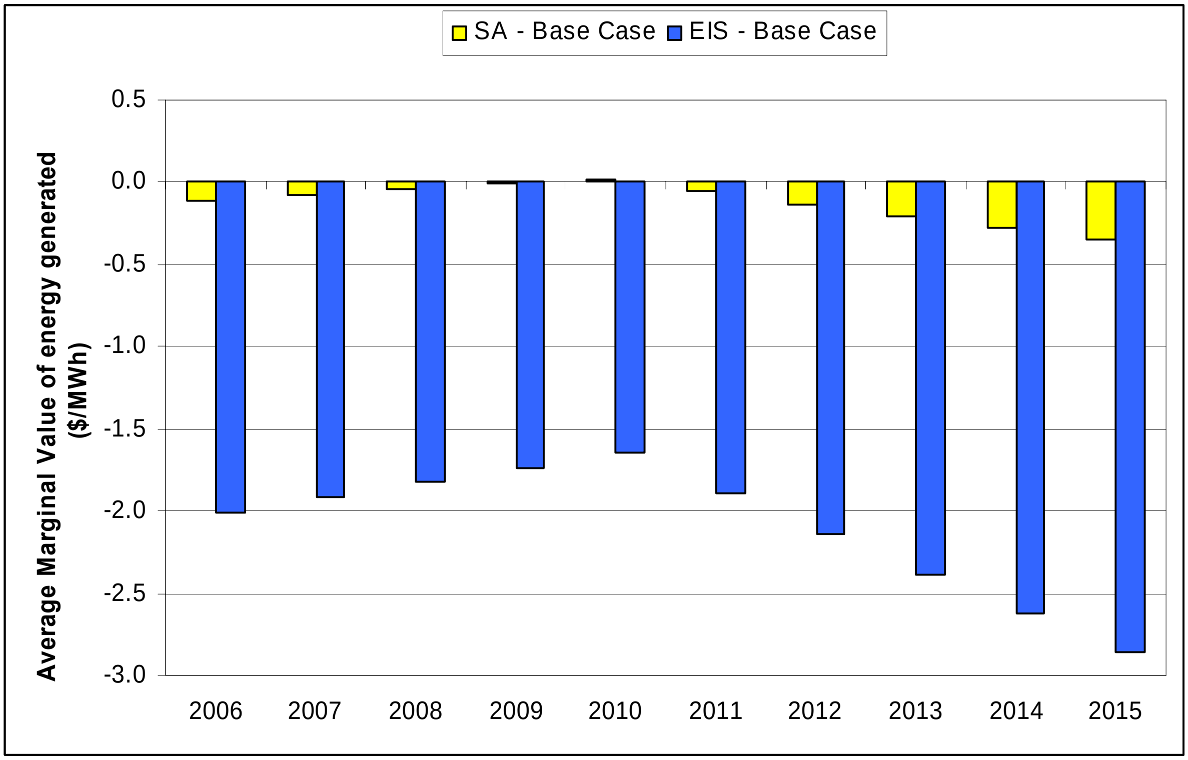
[27] Recall that the simulated values are based on the assumption that generating units bid marginal cost.

**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.

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# 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

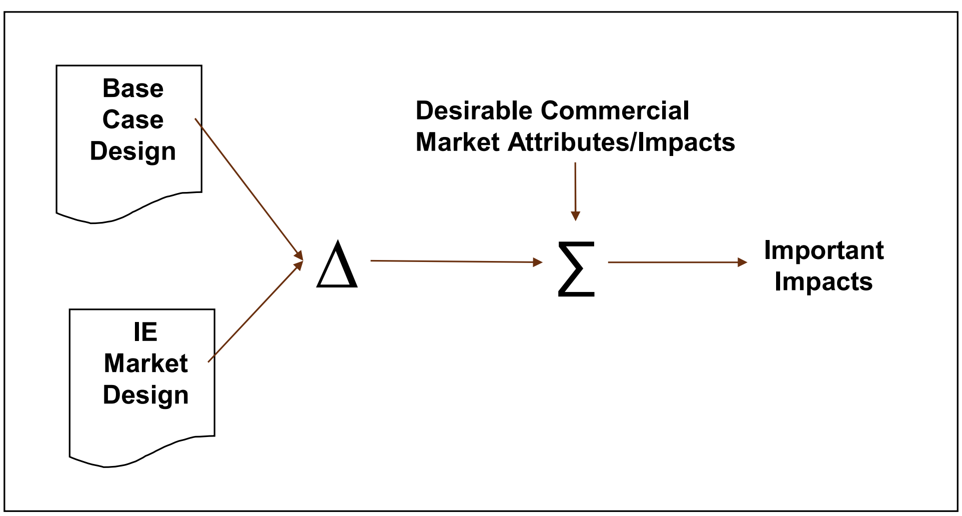
Future-State (EIS) Market Provisions:

- 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.

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**Table 5-1 Commercial Impacts**

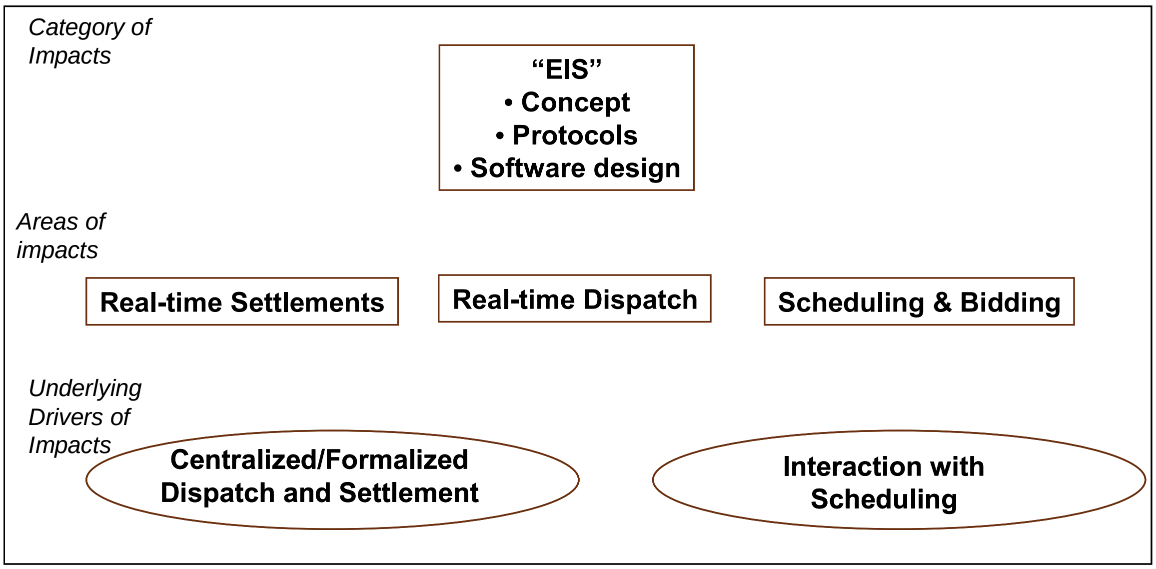
| Commercial Impact | Illustrative Description |
|---|---|
| 1. [Facilitate Development of] **Competitive Markets** | Does the Significant Design Change facilitate or hinder competition or market penetration (the ability of new retailers to compete for load)—for example, through complexity, volatility 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]

[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.

[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.

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# 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.

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**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<br>Chairman, Oklahoma Corporation Commission |
| RSC Vice-President: | Sandra Hochstetter<br>Chairman, Arkansas Public Service Commission |
| RSC Secretary: | Julie Parsley<br>Commissioner, Public Utility Commission of Texas |
| RSC Member: | Steve Gaw<br>Commissioner, Missouri Public Service Commission |
| RSC Member: | Brian Moline<br>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.

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**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 |

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| | 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 |

# 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]

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# 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.

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**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 |

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# 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.

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# 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.

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**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 |

# Appendix 3-2: Fuel Price Assumptions

**MEMORANDUM**

**TO:** SPP CBTF

**FROM:** Alex Rudkevich, Charles River Associates

**SUBJECT**: Fuel Price Forecast

**DATE**: August 30, 2004

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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.

**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.

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**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)**

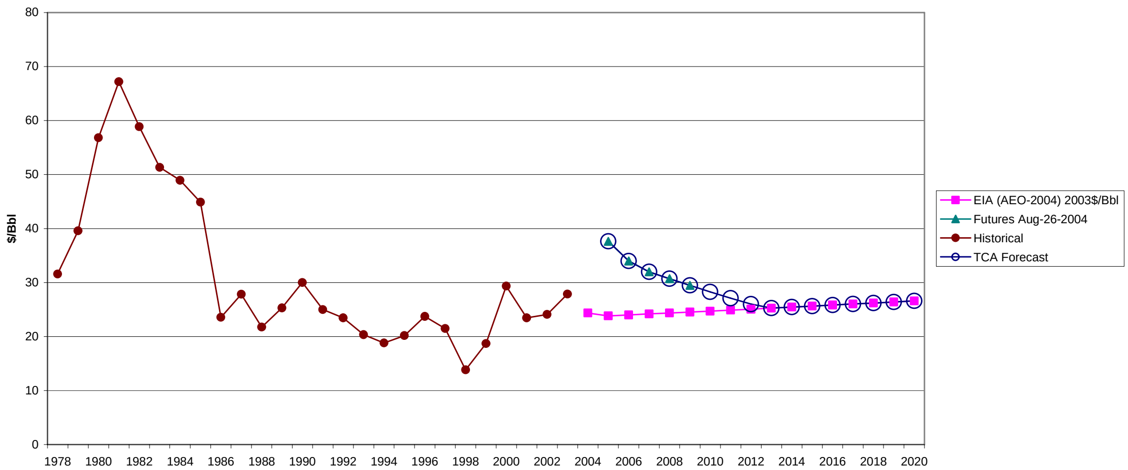


**Figure 2. Natural Gas Spot Prices at Henry Hub: History and Projections (2003$/MMBtu)**

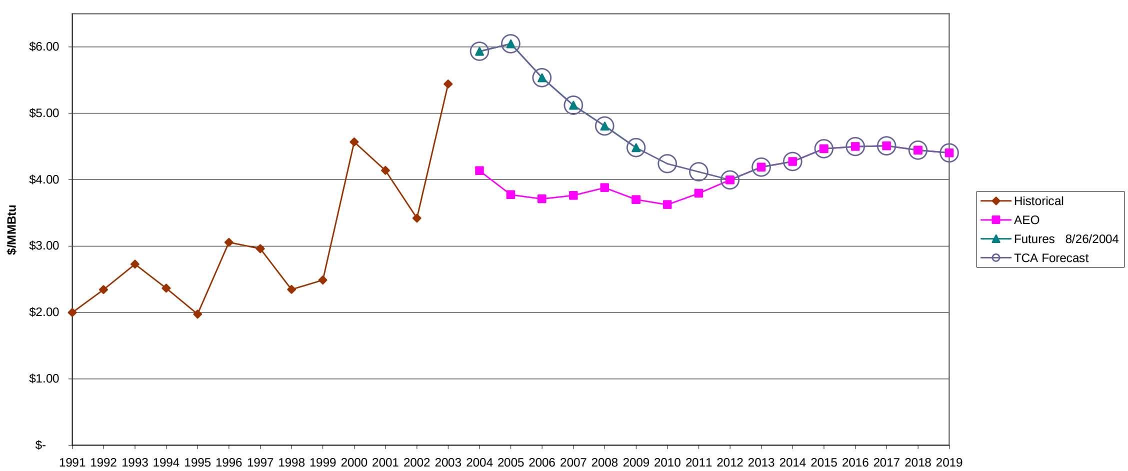

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**Figure 3. Fuel Price Forecast: Midwest Region (MI, IL, WI, IN, MN)**

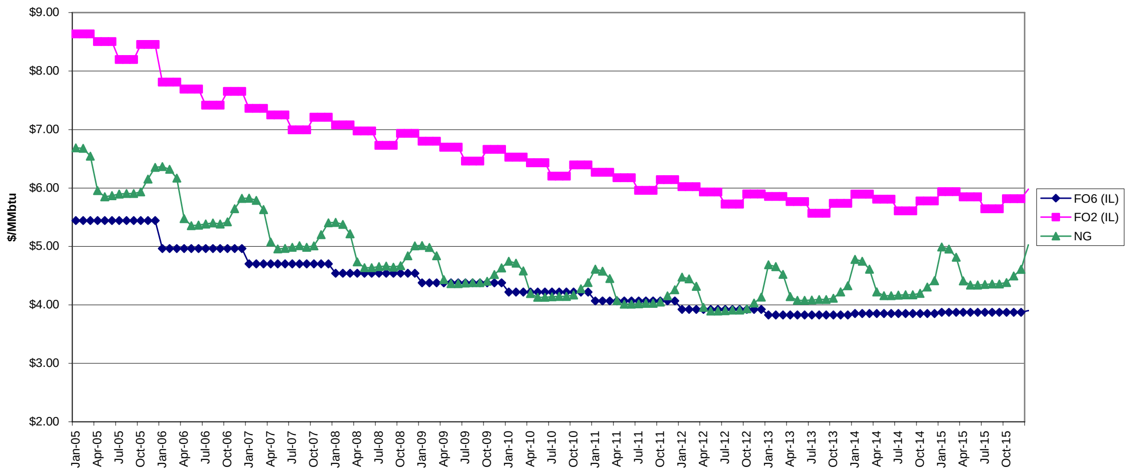


**Figure 4. Fuel Price Forecast: South Atlantic - South (AL, AR, LA, MS, TN)**

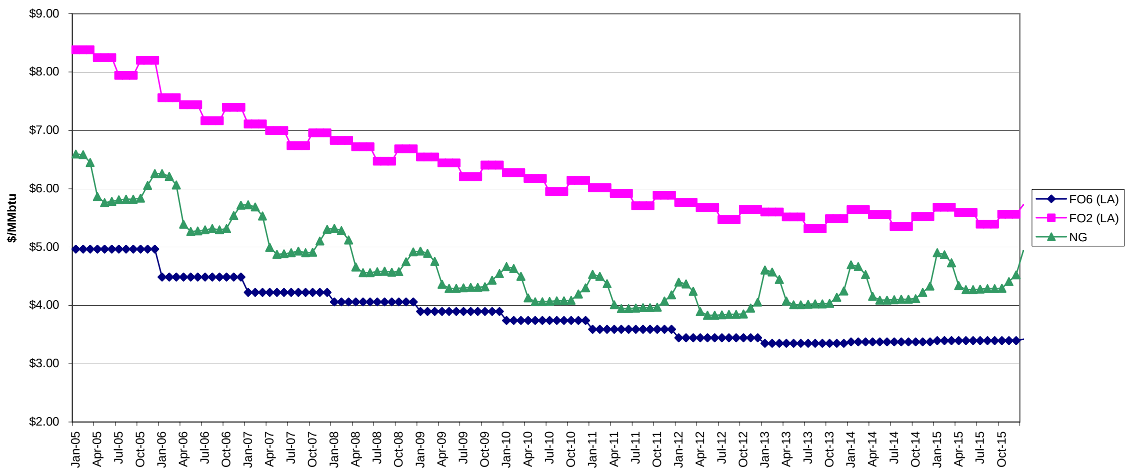

**Figure 5. Fuel Price Forecast: South Atlantic East**

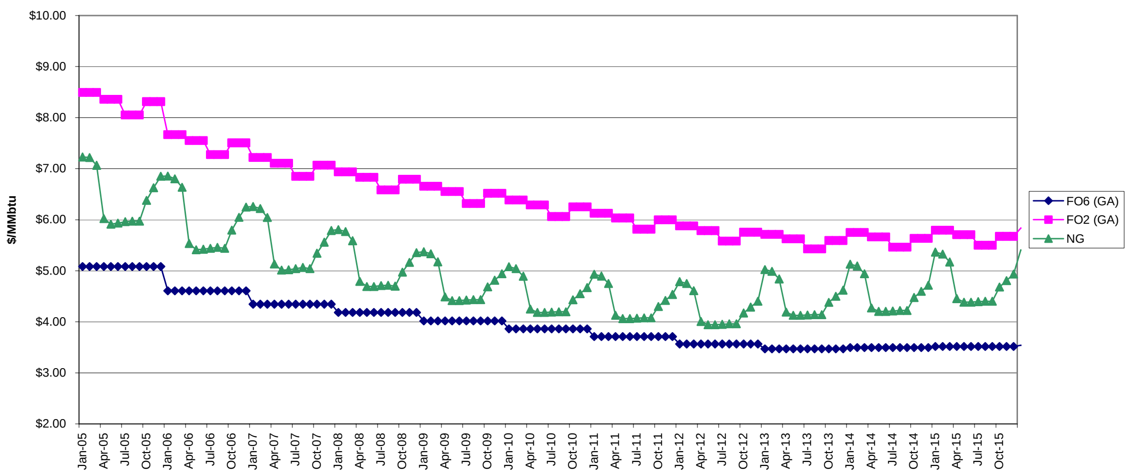


**Figure 6. Fuel Price Forecast: Appalachia (W. PA, WV, OH, KY)**

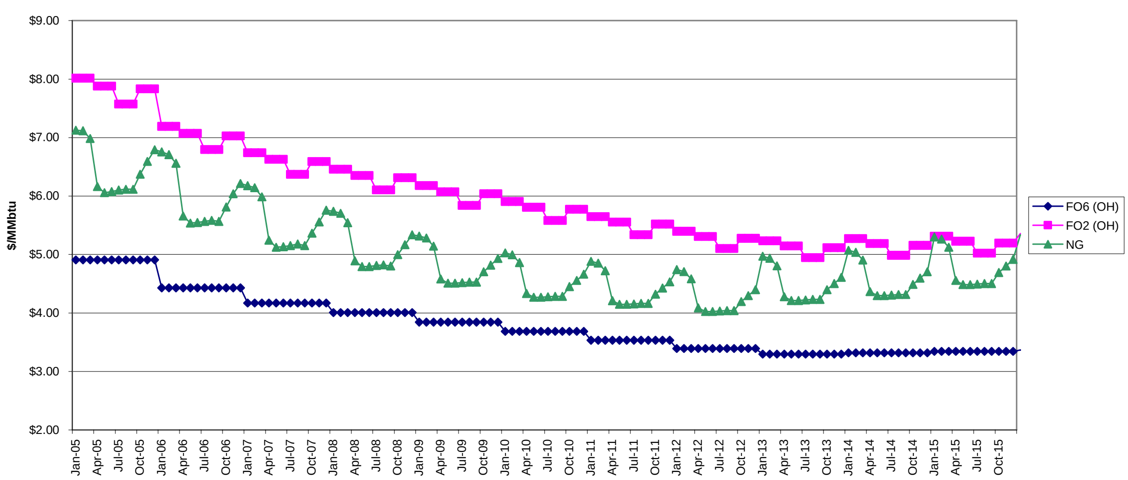

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**Figure 7. Fuel Price Forecast: Midcon (OK, KS)**

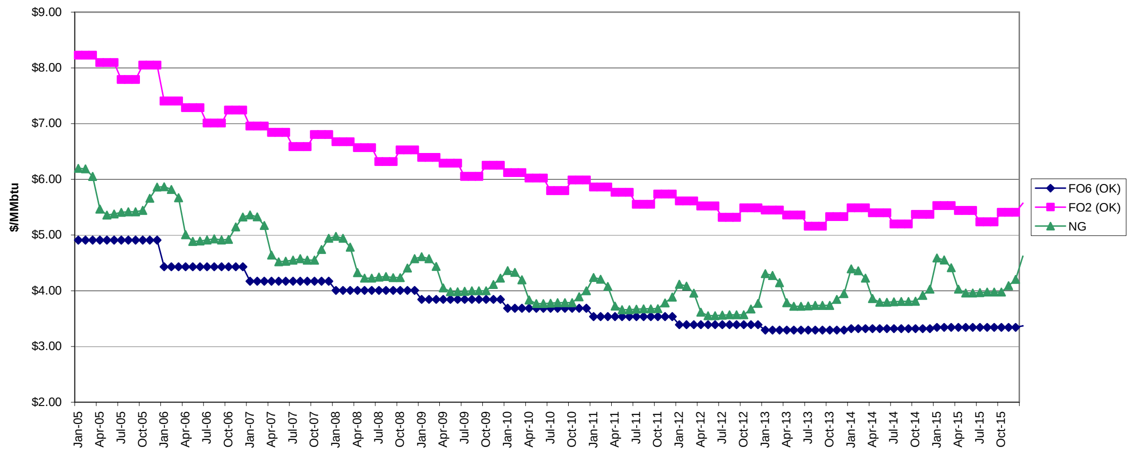



**Figure 8. Fuel Price Forecast: Iowa-Missouri-Nebraska**

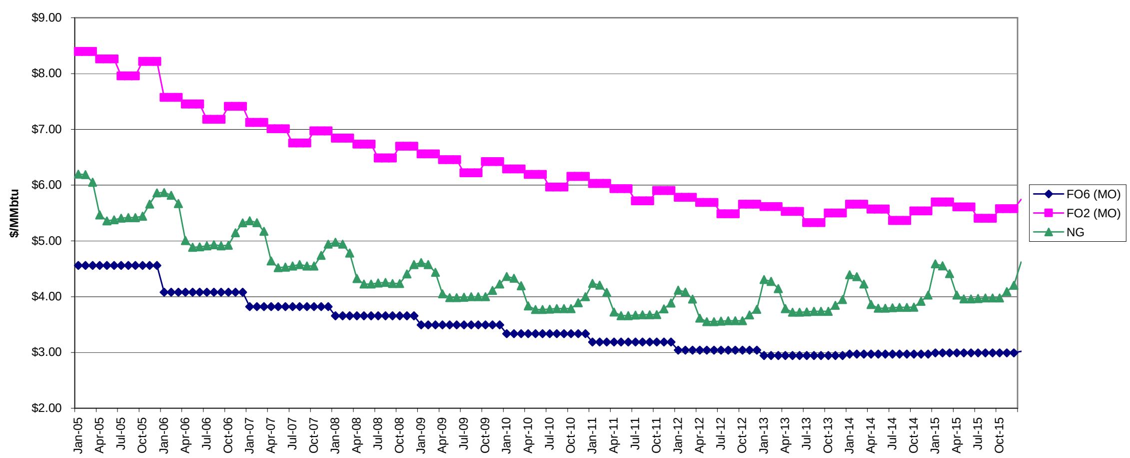
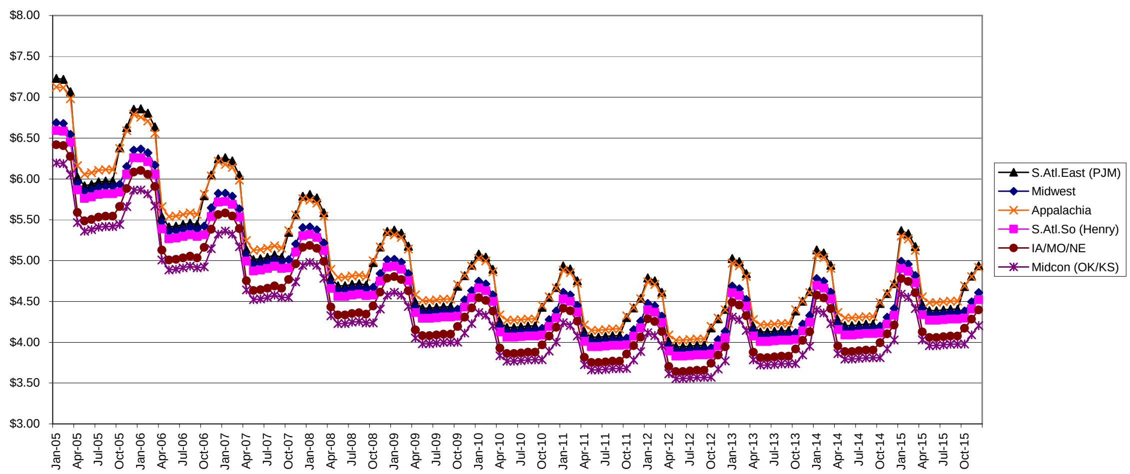


**Figure 9. Comparison of Regional Monthly Natural Gas Prices (2005-2015)**



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# 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 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Region | Scenario | SPP | MISO | SERC | Aquila | Cleco |
| FROM | 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 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Region | Scenario | SPP | MISO | SERC | Aquila | Cleco |
| FROM | 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 |

# 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 | | | | | |

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# 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) |

CHARLES RIVER ASSOCIATES

# 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 |

CHARLES RIVER ASSOCIATES

# 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** | | - | - | - | - | - | - | - | - | - | - | - |

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# 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 |

CRA CHARLES RIVER ASSOCIATES

# 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 |

Schedule BKW-1
Attachment D

CHARLES RIVER ASSOCIATES

# 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 |

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# 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 |
|---|---|---|---|---|---|
| | AEP | OGE | Westar | WFEC | Share |
| 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.*

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# 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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# 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) | | | |

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# 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 |

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# 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) |

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# 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) |

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# 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 |

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# 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*

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# 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.

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**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 |

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## 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 |

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## 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 |

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# 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.

Performance Proven

# Southwest Power Pool

# Cost Benefit Study for Future Market Design

# FINAL Report

# April 7, 2009

Southwest Power Pool

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| | |
|---|---|
| ACE | Area Control Error |
| ACI | Active Carbon Injection |
| AFC | Available Firm Capacity |
| AGC | Automatic Generation Control |
| AS | Ancillary Service(s) |
| ASM | Ancillary Service(s) Market(s) |
| BA | Balancing Authority |
| CAIR | Federal Clean Air Interstate Rule |
| CBS | Cost Benefit Study |
| CC | Combined Cycle |
| CHP | Combined Heat and Power |
| $CO_2$ | Carbon Dioxide |
| CRR | Congestion Revenue Right |
| CT | Combustion Turbine |
| CUC | Centralized Unit Commitment |
| DAM | Day-Ahead Market |
| DC | Direct Current |
| DOE | US Department of Energy |
| DR | Designated Resource |
| EFM | Emissions Forecast Model |
| EIA | Energy Information Administration |
| EIS | Energy Imbalance Service |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| FGD | Flue Gas Desulfurization |
| FTR | Financial Transmission Right |
| GDP | Gross Domestic Product |
| GIQ | Generation Interconnection Queue |
| GWh | Gigawatt Hour |
| Hg | Mercury |
| ICAP | Installed Capacity |
| ISO | Independent System Operator |
| IT | Information Technology |
| JOU | Jointly Owned Unit |
| LIP | Locational Imbalance Pricing |
| LMP | Locational Marginal Price; Locational Marginal Pricing |
| LSE | Load-Serving Entities |

| | |
|---|---|
| MISO | Midwest Independent Transmission System Operator |
| MMBtu | Million British Thermal Units |
| MOPC | SPP Markets and Operations Policy Committee |
| MP | Market Participant |
| MPS | Missouri Public Service |
| MRO | Midwest Reliability Organization |
| MW | Megawatt |
| MWG | Market Working Group |
| MWh | Megawatt Hour |
| NERC | North American Electric Reliability Corporation |
| NITS | Network Integrated Transmission Service |
| $NO_x$ | Nitrogen Oxide |
| NPCC | Northeast Power Coordinating Council |
| NYMEX | New York Mercantile Exchange |
| O&M | Operation and Maintenance |
| OASIS | Open Access Same-Time Information System |
| OPEC | Organization of Petroleum Exporting Countries |
| ORWG | Operating Reliability Working Group |
| PJM | PJM Interconnection (an RTO) |
| PPA | Purchased Power Agreement |
| PUC | Public Utility Commission |
| RSG | Reserve Sharing Group |
| RT | Real Time |
| RTO_SS | Regional Transmission Organization, Scheduling System |
| SCED | Security-Constrained Economic Dispatch |
| SCR | Selective Catalytic Reduction |
| SCUC | Security Constrained Unit Commitment |
| SECI | Sunflower Electric Power Corporation |
| SERC | SERC Reliability Corporation |
| SJLP | Saint Joseph Light and Power |
| SMP | System Marginal Price |
| $SO_2$ | Sulfur Dioxide |
| SPC | Strategic Planning Committee |
| SPP | Southwest Power Pool |
| STEP | SPP Transmission Expansion Plan |
| SWU | Separative Work Units |
| TSR | Transmission Service Right Option |
| UC | Unit Commitment |
| WECC | Western Electricity Coordinating Council |

# Executive Summary

The Southwest Power Pool (SPP) Cost Benefit Task Force (CBTF) commissioned Ventyx to perform both a qualitative and quantitative analysis of the costs and benefits of four options for SPP future market design. These options were developed by the SPP Market Working Group (MWG) to enhance the existing Energy Imbalance Service (EIS) Market. The four options considered were:

1. **Change Case I** - Day-Ahead Market (DAM) with Centralized Unit Commitment (CUC) only (2009-2016)
2. **Change Case IIA** – Day-Ahead Market with Unit Commitment and Co-optimized Ancillary Services Market (2011-2016)
3. **Change Case IIB** – Staged-in Day-Ahead Market with Unit Commitment (2009-2010) and Co-optimized Ancillary Services Market (2011-2016)
4. **Change Case IIC** – Staged-in Ancillary Services Market (2009-2010) and Day-Ahead Market with Unit Commitment (2011-2016)
5. **Change Case III** - Ancillary Services Market (ASM) only (2009-2016)
6. **Change Case IV** - Adding a simplified DAM with CUC

Ventyx performed the quantitative analysis using its PROMOD IV® market simulation application including the Transmission Analysis Module which incorporates detailed powerflow data, security-constrained unit dispatch, transmission loss factors, and other critical elements of nodal market operations. Modeling parameters and methodologies were developed in concert with the CBTF. Input data was provided from production costing data for the Eastern Interconnection maintained by Ventyx with specific modifications in the SPP Market area provided by the CBTF. The study methodology involved the following major tasks:

- A benchmark study was performed for the first twelve months of operation of the SPP EIS Market (3/2007 to 2/2008) to align the model and data with historical market operation under the current EIS market.

- The study Base Case was performed to provide a projection of SPP Adjusted Production Cost (fuel and emissions costs plus variable operations and maintenance costs plus market value of imports minus market value of exports) assuming a continuation of the current EIS market operation for 2009 - 2016.

- Each of the future market design cases requested by SPP was defined, constructed, and executed, and Adjusted Production Cost results from each case were compared to the Base Case to measure the operational benefits of each market design for 2009 - 2016.

- A detailed assessment of costs for staffing, software systems, consulting services, and training was derived for each future market design option based on interviews with SPP staff, interviews with other ISO staff, and independent research.

Costs and benefits for each option were calculated for market participants, balancing authorities, states, and for the SPP Market in total. In addition, a qualitative analysis of the potential impacts of a high SPP wind penetration scenario on cost/benefit study results was also provided.

The study was performed under a collaborative approach with the SPP Cost Benefit Task Force, including weekly conference calls to review project status and four in-person presentations by Ventyx project management to the SPP Market Working Group.

The estimated annual gross benefits of a Change Case at the SPP level are equal to the difference between the adjusted production costs in the Base Case and the adjusted production costs in the Change Case. Table ES-1 summarizes the annual SPP-level gross benefits for each of Change Cases I, IIA, IIB, IIC, and III[1]. During the 2011 – 2016 period (the period for which gross benefits for all three change cases were calculated), gross benefits in Change Case I average approximately $85 million per year, while the Change Case IIA gross benefits average approximately $150 million per year and the annual Change Case III gross benefits average approximately $105 million per year.

**Table ES-1 Gross Benefits (Million $)**

| | I | IIA | IIB | IIC | III |
|---|---|---|---|---|---|
| **2009** | 101 | | 101 | 34 | 34 |
| **2010** | 60 | | 60 | 52 | 52 |
| **2011** | 94 | 171 | 171 | 171 | 92 |
| **2012** | 124 | 160 | 160 | 160 | 109 |
| **2013** | 75 | 132 | 132 | 132 | 93 |
| **2014** | 75 | 136 | 136 | 136 | 98 |
| **2015** | 70 | 137 | 137 | 137 | 109 |
| **2016** | 79 | 153 | 153 | 153 | 119 |
| **Total** | **679** | **889** | **1,050** | **975** | **706** |
| **NPV @ 5.9%** | **518** | **637** | **781** | **713** | **515** |
| **NPV @ 8.3%** | **469** | **560** | **699** | **633** | **457** |

[1] This study was begun in early 2008, at a point in time when it seemed feasible to start either the Day-Ahead Market (Change Case I) or the Ancillary Service Market (Change Case III) in January 2009; but not feasible to start the combined Day-Ahead and Ancillary Services Market (Change Case IIA) until January 2011. All of the analysis was performed consistent with these assumptions, and the analytic results summarized in this report are presented in a manner consistent with these assumptions. However, due to the time required to complete the study, it is no longer feasible to start either the Day-Ahead Market or the Ancillary Service Market in January 2009. Moreover, subsequent investigation (outside of this study) indicates that it might not be feasible to start either the Day-Ahead Market or the Ancillary Services Market earlier than the combined Day-Ahead and Ancillary Services Market.

It is important to note that the estimated gross benefits associated with implementing both the Day-Ahead Market and the Ancillary Services Market (Change Case IIA) are less than the sum of the estimated benefits for implementing just one of the two markets (Change Cases I and III). The reason for this is that the estimated gross benefits of Change Case IIA could at most be equal to the sum of the estimated gross benefits of Change Cases I and III, because the estimated gross benefits for each of those Change Cases reflects a separate "optimization" of gross benefits with respect to Day-Ahead Commitment (I) and Ancillary Services (III). However, the market changes addressed in Change Case IIA do not achieve this theoretical ceiling because the objectives that are considered in the separate optimization problems in Change Cases I and III but jointly in Change Case IIA are occasionally in conflict, i.e., one commitment and dispatch leads to the least-cost solution for Change Case I, and a different commitment and dispatch leads to the least-cost solution for Change Case III.

The last three rows of Table ES-1 report the estimated total undiscounted gross benefits in each change case, as well as the net present value[2] of the estimated gross benefits at discount rates of 5.9% and 8.3%. As would be expected from the preceding discussion, the undiscounted and discounted total gross benefits are higher for Change Cases IIA, IIB, and IIC than for Change Cases I or III; those for IIB (IIC) are higher than IIA because IIB (IIC) includes the Day-Ahead Market (Ancillary Services Market) in 2009 and 2010, while IIA (Day-Ahead plus Ancillary Services Markets) assumes the new market does not begin until 2011.

In order to achieve the estimated gross benefits portrayed in Table ES-1, both SPP and each of the market participants must incur both capital expenditures and ongoing, annual operating expenses. Table ES-2 summarizes the estimated total annual implementation capital and operating costs incurred by SPP and the market participants. Note that some costs were assumed in the study to be incurred in 2008, in order to support an assumed market commencement of January 1, 2009.

[2] All net present values have a base date of January 1, 2008.

**Table ES-2 Annual SPP and Market Participant Implementation Costs (Million $)**

| | Case I | Case II A | Case II B | Case II C | Case III |
|---|---|---|---|---|---|
| **2008** | 36 | 0 | 37 | 34 | 26 |
| **2009** | 24 | 2 | 24 | 11 | 9 |
| **2010** | 27 | 36 | 28 | 14 | 11 |
| **2011** | 28 | 32 | 32 | 32 | 12 |
| **2012** | 30 | 34 | 34 | 34 | 12 |
| **2013** | 31 | 36 | 36 | 36 | 13 |
| **2014** | 33 | 37 | 37 | 37 | 14 |
| **2015** | 34 | 39 | 39 | 39 | 14 |
| **2016** | 36 | 41 | 41 | 41 | 15 |
| **Total** | **278** | **258** | **308** | **278** | **128** |
| **NPV @ 5.9%** | **215** | **188** | **237** | **210** | **101** |
| **NPV @ 8.3%** | **196** | **167** | **215** | **190** | **93** |

Table ES-3 through Table ES-5 display the estimated annual gross benefits, costs, and net benefits for each of the Change Cases. The bottom three rows of each table display the total (undiscounted) sum of the three variables, as well as net present values at discount rates of 5.9% and 8.3%. The tables can be summarized as follows:

- Total estimated net benefits are positive for all Change Cases, including all three variations of Change Case II.

- Between the Change Cases, IIB has higher estimated net benefits, followed by IIC and IIA. The reason for this is that IIA does not start yielding net benefits until 2011, while IIB and IIA begin generating positive net benefits in 2009.

- The estimates of gross benefits are sensitive to a number of assumptions that were made during the study, such as fuel prices and carbon allowance prices. However, in all Change Cases, gross benefits are more than 225% of the costs. As a result, if actual costs turned out to be 40% higher than estimated here, and actual gross benefits turned out to be 40% lower than estimated here, actual net benefits would still be positive for these all Change Cases.

- Once each market structure begins operation (i.e., 2009 for Change Cases I, IIB, IIC, and III, 2011 for Change Case IIA), the annual net benefits are consistently positive. Thus, there is nothing to be gained by trying to "time" the start of a new market to occur in a year during which "attractive" conditions might occur.

**Table ES-3 Change Case I Gross Benefits, Costs, and Net Benefits (Million $)**

| | Costs | Gross Benefits | Net Benefits |
|---|---|---|---|
| **2008** | 36 | 0 | (36) |
| **2009** | 24 | 101 | 78 |
| **2010** | 27 | 60 | 33 |
| **2011** | 28 | 94 | 66 |
| **2012** | 30 | 124 | 95 |
| **2013** | 31 | 75 | 44 |
| **2014** | 33 | 75 | 43 |
| **2015** | 34 | 70 | 36 |
| **2016** | 36 | 79 | 43 |
| **Total** | **278** | **679** | **400** |
| **NPV @ 5.9%** | **215** | **518** | **303** |
| **NPV @ 8.3%** | **196** | **469** | **273** |

**Table ES-4 Change Case II Gross Benefits, Costs, and Net Benefits (Million $)**

| | Case II A | | | Case II B | | | Case II C | | |
|---|---|---|---|---|---|---|---|---|---|
| | Costs | Gross Benefits | Net Benefits | Costs | Gross Benefits | Net Benefits | Costs | Gross Benefits | Net Benefits |
| **2008** | 0 | 0 | 0 | 37 | 0 | (37) | 34 | 0 | (34) |
| **2009** | 2 | 0 | (2) | 24 | 101 | 77 | 11 | 34 | 23 |
| **2010** | 36 | 0 | (36) | 28 | 60 | 32 | 14 | 52 | 38 |
| **2011** | 32 | 171 | 139 | 32 | 171 | 139 | 32 | 171 | 139 |
| **2012** | 34 | 160 | 126 | 34 | 160 | 126 | 34 | 160 | 126 |
| **2013** | 36 | 132 | 97 | 36 | 132 | 97 | 36 | 132 | 97 |
| **2014** | 37 | 136 | 99 | 37 | 136 | 99 | 37 | 136 | 99 |
| **2015** | 39 | 137 | 98 | 39 | 137 | 98 | 39 | 137 | 98 |
| **2016** | 41 | 153 | 112 | 41 | 153 | 112 | 41 | 153 | 112 |
| **Total** | **258** | **889** | **632** | **308** | **1,050** | **742** | **278** | **975** | **697** |
| **NPV @ 5.9%** | **188** | **637** | **448** | **237** | **781** | **544** | **210** | **713** | **503** |
| **NPV @ 8.3%** | **167** | **560** | **393** | **215** | **699** | **484** | **190** | **633** | **443** |

**Table ES-5 Change Case III Gross Benefits, Costs, and Net Benefits (Million $)**

| | Costs | Gross Benefits | Net Benefits |
|---|---|---|---|
| **2008** | 26 | 0 | (26) |
| **2009** | 9 | 34 | 24 |
| **2010** | 11 | 52 | 41 |
| **2011** | 12 | 92 | 80 |
| **2012** | 12 | 109 | 97 |
| **2013** | 13 | 93 | 80 |
| **2014** | 14 | 98 | 85 |
| **2015** | 14 | 109 | 94 |
| **2016** | 15 | 119 | 103 |
| **Total** | **128** | **706** | **578** |
| **NPV @ 5.9%** | **101** | **515** | **414** |
| **NPV @ 8.3%** | **93** | **457** | **364** |

Ventyx also estimated gross benefits for each of the states, balancing authorities, and market participants in SPP. These estimates can be summarized as follows:

- **States** –Estimated gross benefits are positive (or negative, but less than $10 million in absolute value, which Ventyx considers essentially the same as zero) for all but two (out of 128) combinations of Change Case, year, and state. Missouri, Nebraska, and Oklahoma have large positive estimated gross benefits in all Change Cases and all years, Texas has large positive estimated gross benefits in Change Cases IIA and III in all years, Arkansas has consistently positive and occasionally large estimated gross benefits in all Change Cases and all years, and the other three states do not display a consistent pattern.

- **Balancing Authorities** – Estimated gross benefits are positive (or small negative) for all but one (out of 224) combinations of Change Case, year, and balancing authority. In Change Cases I and IIA, AEPW_BA, KCPL, OGE_BA, OPPD, WFEC, and WRI_BA have consistently large positive estimated gross benefits; EDE, GRDA, and NPPD also consistently have large positive estimated gross benefits in Change Case IIA. In Change Case III, only AEPW_BA consistently has large positive estimated gross benefits.

- **Market Participants** – Excluding Wind IPPs, estimated gross benefits are positive (or small negative) for all but one (out of 336) combinations of Change Case, year, and market participant. In Change Cases I and IIA, KCPL, IPPs, OGE, OPPD, and WFEC have consistently large positive estimated gross benefits. CSWS (AEPW), EDE, GRDA, and NPPD also have consistently large positive estimated gross benefits in Change Case IIA. In Change Case III, CSWS (AEPW) and IPPs have consistently large positive estimated gross benefits. The Wind IPPs have negative (and frequently large) estimated gross benefits in Change Cases I and IIA, because these Change Cases result in lower locational marginal prices (LMPs), which reduces the estimated revenues that these generators receive. Non-wind IPPs have large positive estimated gross benefits in these Change Cases because, although they receive lower LMPs for their output, their generation increases significantly as a result of improved market efficiency.

It is important to recognize that Ventyx has significantly more confidence in the SPP-level results than in these segment-level results, particularly as the segments become smaller (e.g., we have less confidence in the market participant results than the state results). In our view, the SPP-level results should be interpreted as conclusive, while the segment-level results should be interpreted as indicative; i.e., Ventyx concludes that at the SPP level the gross benefits exceed the implementation costs, while the state-level results (for example) only indicate that gross benefits are likely to be larger in Missouri than in Kansas.

Before stating recommendations, it is also important to recognize the limitations of the analysis. Most importantly, as in all studies of this type, Ventyx had to make a large number of assumptions. The results, even those at the SPP level, are sensitive to these assumptions, particularly those regarding future fuel prices, U.S. environmental policy (e.g., greenhouse gas emissions controls), and the amount of new wind capacity built in SPP. The model Ventyx used to derive the results also has a large number of assumptions, both implicit and explicit, about how market participants will behave under each of the sets of market rules that were considered.

Having said that, based on the SPP-level results, Ventyx recommends that SPP institute the combined DAM plus ASM (i.e., Change Case II) as quickly as possible. Ventyx believes there is no benefit to waiting. If the two types of changes (DAM, ASM) cannot be implemented simultaneously due to resource constraints, staging implementation of these two markets (i.e., first one, and the second one or more years later), would be beneficial. In such an event, the DAM should be implemented first, then the ASM; again, each should be instituted as quickly as possible.

# 1 Study Background and Overview

The Southwest Power Pool (SPP) Market Working Group (MWG) was directed by the SPP Markets and Operations Policy Committee (MOPC) and the SPP Strategic Planning Committee (SPC) to develop a proposal for future market development in SPP to replace or refine the real-time (RT) Energy Imbalance Service (EIS) Market. These future market designs would take further advantage of the diversity of resource assets, optimize utilization of the transmission system within Southwest Power Pool, and minimize the overall cost to its consumers. The MWG held several educational meetings to review and understand the designs of other markets to determine if SPP should implement similar aspects as an expansion of its current EIS market. Based on those sessions, the MWG determined that adding 1) a Day-Ahead Market with Centralized Unit Commitment and 2) an Ancillary Services Markets both have potential to generate significant savings to SPP market participants. In order to accommodate these future market designs/enhancements, the MWG further decided that changes in the way transmission rights are handled should be considered.

## 1.1 Proposed SPP Market Design

The proposed design of the SPP energy markets includes multi-settlement starting with a financially binding Day-Ahead Market (DAM) in which resources would submit offers, including start-up and minimum load costs and other characteristics (e.g., minimum up and down time, ramp up and ramp down rates). Market Participants will submit Demand Bids for what they are willing to pay and Resource Offers for what they are willing to provide. Market Participants are also allowed to self-commit/self-schedule resources and bilateral agreements. The DAM clears nodally under a centralized Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) process. The real-time process is deployed in a similar fashion to the current EIS Market in that the total load is met through a SCED using offered and self-dispatched resources. Any quantitative deviations (i.e., imbalances) at the Settlement Locations from day-ahead cleared positions to real-time are settled at the real-time LMPs as imbalances.

In the DAM, SPP utilizes start-up and minimum load resource costs and characteristics along with an incremental offer curve to perform the SCUC and SCED. As part of the DAM, the objective function for the unit commitment algorithm ensures that bid-in demand and Ancillary Service obligations are satisfied with energy and capacity up to the point that the nodal costs do not exceed the buyers bid price. Following the clearing of the DAM, market participants would have a chance to self-commit resources. SPP utilizes the start-up and minimum load costs/characteristics supplied with the Real-Time Market resource offers to commit any additional capacity necessary to reliably meet the total forecasted load and ancillary service obligations for each hour of the upcoming operating day. This additional capacity/energy is committed using a SCUC algorithm; however, the objective function for this process involves minimization of resource costs at the minimum resource output that SPP requires for reliability. During Real-Time (RT) operations SPP continually assesses upcoming hours as load forecasts are updated and as generation or transmission status changes occur to ensure that SPP has enough capacity on-line and available to meet its total load and ancillary service obligations.

To help ensure enough capacity is available for SPP to meet the energy and Ancillary Service needs of the market footprint, Market Participants serving load must offer or self-commit a sufficient amount of Designated Resource (DR) capacity into the DAM to meet their projected load and Ancillary Service obligations. Offering of Non-Designated Resources will be optional.

### 1.1.1 Bilateral Transactions

Bilateral trading is allowed between parties in order that they may hedge against DAM and RT market prices if desired. Under a bilateral trade, the total scheduled amount of energy at each Settlement Location is removed from any exposure to the LMP prices. Congestion charges for the price differential between the Sink and Source of those bilateral transactions will be applied however. The DAM design supports bilateral energy trading that does not require them to hold transmission rights or reservations.

In order to increase participation and access to the SPP Market by parties that do not have assets within the SPP Market, Dispatchable Schedules are permitted to offer/bid in the DAM from external boundary Settlement Locations. These schedules are submitted with an associated price for the megawatt (MW) amount and the SCUC would consider each schedule an offer or bid as appropriate at that location when the schedule clears the DAM. If the schedule clears, the internal location has the impact of the schedule reflected in its energy settlement, and the MP submitting the schedule would pay or be paid the clearing price at the boundary. Congestion charges for the LMP differential between the source Settlement Location and the sink Settlement Location is paid by the designated responsible parties on the schedule. Any deviation in real-time from the day-ahead cleared value is settled at real-time prices.

The DAM design would allow “Up to Congestion” schedules, which clear based on the LMP differential between the source and the sink Settlement Locations. If the differential is below the submitted value, the schedule is cleared and settled in the DAM.

SPP would allow real-time and day-ahead injections and withdrawals from the energy market as a price taker. These are settled in the appropriate market, and if cleared in the DAM, any deviation from the schedule in real-time is settled at real-time prices.

### 1.1.2 Virtual Bids/Offers

To allow for risk management, greater trading opportunities, and enhanced system reliability, Virtual Bids and Offers are allowed in the DAM at any Settlement Location. Any Virtual Bid or Offer cleared and settled day-ahead has an automatic 0 MW meter value in real-time, therefore the entire amount is considered a deviation from day-ahead and is settled in real-time. Allowing Virtual Bids and Offers in the DAM has been shown elsewhere to reduce the price volatility between the day-ahead and real-time markets. Although some view Virtual transactions as pure speculation, they are also an important risk management mechanism that can be used by participants with resource and load assets to hedge their exposure to market energy prices.

### 1.1.3 Hubs

The DAM design allows for definition of one or more trading hubs within SPP to facilitate bilateral trading. Bilateral scheduling and Virtual transactions utilize hub(s) as Settlement Locations. The MWG or other appropriate group analyzes the various market behaviors and seek input from stakeholders to identify potential hubs.

### 1.1.4 Ancillary Services Market Design

The proposed Ancillary Service Market (ASM) design is for Regulation Reserve, Spinning Reserve, and Supplemental Reserves. As with the energy market, the ASM is multi-settlement, clearing in the day-ahead, and deviations are settled in real-time. Offers may be submitted for any or all services, and they are cleared in priority with a co-optimized algorithm to achieve the least cost overall solution for energy and ancillary services. SPP is operating as a single BA, and it is assumed that SPP centrally deploys ancillary services directly to those purchasing the services.

SPP would function as a consolidated balancing area and changes to the Reserve Sharing Criteria may occur as a result. In the ASM, any entity may provide reserves to meet the obligation.

Regulation Reserve Service is the highest priority Ancillary Service behind only energy. The regulation requirement criteria must be established for the SPP Market area. The SPP ORWG or other appropriate group determines the total requirement and also determines if there is any need for consideration of zonal constraints when clearing a service. The final resources used in real time for regulation service is determined prior to the start of each hour and is centrally deployed by SPP as a single balancing authority. A capacity payment based on the offer and a make-whole guarantee (excluding “lost opportunity costs”) is made to participants providing Regulation Service. In addition, a “mileage” payment based on performance for movement of the resource is being considered.

Spinning Reserve Service is the next priority service. The SPP Reserve Sharing criteria would be used to determine the overall requirement for the SPP Market footprint. External RSG Market Participants continue to participate in the RSG program as they do today. The SPP ORWG or other appropriate group must determine if there are any zonal constraints to be considered when clearing the service. Spinning Reserves for any Reserve Sharing Event within the SPP Market Area are centrally deployed by SPP and are the next highest priority Ancillary Service.

Supplemental Reserve Service is the lowest priority service. The SPP Reserve Sharing criterion is used to determine the overall requirement for the SPP market footprint. External RSG Market Participants continue to participate in the RSG program as they do today. The SPP ORWG or other appropriate group determines if there are any zonal constraints to be considered when clearing the service. Supplemental Reserves for any Reserve Sharing event within the SPP market footprint is centrally deployed by SPP as necessary.

### 1.1.5 Transmission Rights

During times of congestion, LMP pricing will reflect congestion costs resulting in the collection of more revenues from loads than payments made to resources. The transmission rights structure determines how and when those excess charges will be distributed to transmission rights holders. Transmission Rights approaches in other markets have all been subject to significant discussion regarding conversion of existing physical Point-to-Point and Network Integrated Transmission Service (NITS) rights to some form of Financial Transmission Right (FTR), Congestion Revenue Right (CRR), or Auction Revenue Right. If there is a corresponding physical delivery of energy, the FTR on any congested path renders the holder financially neutral or indifferent to congestion. However, if there is no corresponding physical delivery of energy by the holder of the FTR, the FTR may create revenue or impose a charge to the holder. Any entity may hold an FTR on a path whether they are transacting business on that path or not.

As an alternative to FTRs, SPP is considering modifications to current reservation and scheduling rules to create a Transmission Service Right (TSR) that will facilitate additional bilateral trading. The modification centers on some bilateral transactions having TSR while allowing for bilateral transactions without rights as well. This perpetuates the need for participants to continue to reserve transmission service on the Open Access Same-time Information System (OASIS) to get a TSR and the need to have a scheduling mechanism that validates the existence of a firm transmission service reservation.

## 1.2 Study Scope

SPP issued a request for proposal to study the implementation costs and operational benefits of adding a Day-Ahead Market with Centralized Unit Commitment and Ancillary Services

Market. Ventyx was selected to perform the study and provide quantitative and qualitative analysis on the impact of these market design changes.

- **Base Case** - the current SPP EIS market without a consolidated Balancing Authority, the 2008 Q2 SPP Transmission Expansion Plan (STEP), and the 2008 Nebraska and GMOC Transmission Expansion Plans expanding from 2009 – 2016.
- **Change Case I** - a Day-Ahead Market with Unit Commitment. This case assessed adding only a multi-settlement energy market without an Ancillary Services Market from 2009 - 2016. Years 2014 – 2016 were extrapolated at the same rate the Change Case IIA changed from year to year.
- **Change Case IIA** - a Day-Ahead Market with Unit Commitment and an Ancillary Service Market. This "All Inclusive" case was assessed with start up costs beginning in 2009 and 2010 with the Market enhancements functional in 2011 and assessed through year 2016.
- **Change Case IIB** - a Day-Ahead Market with Unit Commitment in 2009, 2010 and "All Inclusive" market design for 2011-2016.
- **Change Case IIC** - an Ancillary Service Market 2009, 2010 and an "All Inclusive" market design for 2011-2016.
- **Change Case III** - an Ancillary Service Market Addition. This case assessed adding only the Co-optimized Ancillary Services Market for 2009 – 2016. Years 2014 – 2016 were extrapolated at the same rate the Base Case changed from year to year.
- **Change Case IV** - a Simplified Day-Ahead Market with Unit Commitment. This case assessed a simplified approach to a Day-Ahead Market with limited additional participation features. It would still maintain the Centralized Unit Commitment aspects described for the more robust Day-Ahead Market, but would not allow virtual bids and offers, dispatchable schedules, or up-to-congestion schedules. In addition, day-ahead settlement would not necessarily provide price certainty since schedules in place at the time of the Day-Ahead Market would still be subject to curtailment in real-time, which could expose all or part of the load to real-time pricing even if the load was equal to its Day-Ahead cleared amount.

At SPP's request, Ventyx also analyzed the relative costs to implement FTR and TSR transmission rights systems, as well as possible effects of these systems on market participants. The results of this analysis are summarized in a separate document.

# 2 Methodology

## 2.1 Benefits Methodology

The Cost Benefit Study (CBS) performed by Ventyx evaluates the merits of proposed energy market enhancements. This cost/benefit study assesses market design changes described in the Proposed High Level Design for Southwest Power Pool Future Market Development (High Level Design) document developed by the SPP Market Working Group (MWG). The study measures the costs and benefits of moving from the base case to the change cases and sensitivities described in the Request for Proposals issued by SPP. These change cases include:

- Change Case I – Day-Ahead Market with Centralized Unit Commitment only (2009-2016)
- Change Case IIA – Day-Ahead Market with Unit Commitment and Co-optimized Ancillary Service Market (All Inclusive 2011-2016)
- Change Case IIB – Staged-in Day-Ahead Market with Unit Commitment (2009-2010) and Co-optimized Ancillary Service Market (2011-2016)
- Change Case IIC – Staged-in Ancillary Service Market (2009-2010) and Day-Ahead Market with Unit Commitment (2011-2016)
- Change Case III – Ancillary Service Market only (2009-2016)
- Change Case IV – Simplified Day-Ahead Market with Unit Commitment

This study provides the Market Participants of SPP with a detailed analysis of each case except Case IV that allows them to compare the relative costs and benefits of different approaches to market changes. Case IV is analyzed on a qualitative basis only. In considering such significant and complex market changes, Ventyx has designed and carried out a methodical and detailed study to capture the nuances of the various future market structures.

### 2.1.1 Model Benchmarking

Critical factors in performing the cost benefit analysis of market changes included an accurate representation of not only the future proposed operating rules, but also of the current baseline market operations. Ventyx, which has considerable experience in performing in-depth benchmarks of actual historical operations, performed a detailed benchmark for the LMP and production cost model to develop confidence that the model was reasonably representing the existing power market in the base case. This benchmarking process was focused on the key input data and output that would characterize the cases to be analyzed in the study. Based on the benchmark, model input data was tuned to reflect actual historical conditions, but was not overly constrained so that operations could respond to the future market conditions and market design rules that will be evaluated in the study.

The benchmark is centered on the period from March 1, 2007 through February 29, 2008, which comprised the first twelve months of operation of the SPP EIS market. The benchmark model included the 2007 SPP market participants, Nebraska companies, GMOC and neighboring markets. For the 2007 SPP market participants, data models were constructed to replicate operations of the SPP EIS market comprising ten balancing authorities. The Nebraska and GMOC companies were modeled as four balancing areas (NPPD, OPPD, LES and GMOC) with separate commitment and reserve operating requirements. The benchmark entails criteria achieving a match between reasonably modeled monthly average on-peak and off-peak energy prices and applicable historical data. Ventyx also benchmarked unit operations in the model using historical capacity factors of SPP generators. The following input data from the historical period were entered into the model to perform the benchmark analysis.

1. **Actual hourly load data** – Benchmarking to actual market conditions requires a good representation of the hourly load distribution throughout the market. Hourly load data for PJM, MISO, and SPP was obtained from data filings and requests made directly to the Independent System Operators (ISO). Load data for other areas in the footprint (non-MISO MRO areas, etc.) that were not available through filings were approximated by scaling the nominal load profiles of neighboring areas for which data is available (SPP, PJM and MISO areas) to provide reasonable consistency.
2. **Actual Monthly Average Fuel Costs -** Historical cash prices for natural gas at the Henry Hub were incorporated into the benchmark process.
3. **Operating reserves** – Balancing Authorities within MISO and SPP are responsible for maintaining their own operating reserves. This is accomplished by the BA adjusting its generator bid characteristics to block out capacity on those generators which the BA intends to use to carry its operating reserve. Separate spinning reserve requirements were added to the model for each Balancing Area based on the reserve sharing allocation process in place in 2007 for SPP, MISO, and MRO regions. PJM was also modeled based on reserve regions modeled by the PJM ISO during 2007.
4. **Generator actual random outages and transmission outages** - Outages and partial derations lasting more than 24 hours were included in the model.
5. **BA Economic Threshold Rates** - Economic commitment and dispatch threshold rates ($/MWh) were modeled between the SPP Balancing Authorities, and between SPP and other markets to improve the simulation results correspondence to historical values. These economic thresholds are discussed more in section 2.1.2.
6. **Unit Dispatch Adjustment Factors –** For units that show significant deviation between model operations and historical dispatch levels, adjustment factors were developed to scale the bid costs of the units as needed to better align benchmark results.

Additional details related to the representation of SPP generators were reviewed with SPP staff and market participants to improve the accuracy of unit input data.

Comparisons of generation were performed for individual generators, generator category and market participant. Table 2-1 and Table 2-2 below illustrate the results of the benchmark simulation. Coal-fired, pumped storage hydro, and steam gas-fired generation were very close to the historical levels. As expected, peaking and other cycling generation varied more. CT operation was 16% high. The largest deviation occurred on combined cycle units, for which it is more difficult to model all operating conditions and cycling decisions. Additionally, a review of the difference between actual and simulated generation for some market participants are important since the study would evaluate market design impact at the market participant level as well as at the SPP level. Generation deviations by Market Participant varied from 7% lower than actual, to 29% higher. Larger deviations tend to occur with Market Participants which have more gas-fired steam units and other cycling units. The simulated generation in total for the SPP Market was 3% higher than actual operations. This difference represents a reduction in SPP net purchases from other markets in the benchmark simulation. The benchmark generation results were judged to be reasonable for the cost benefit study.

Average monthly on-peak and off-peak SPP sub-regional hub prices were reviewed also and deemed reasonable for the future look into the cost benefit of the various market designs.

**Table 2-1 Generation Benchmark Comparison by Category (MWh)**

| Major Categories | Actual Generation | PROMOD IV Generation | Delta (%) |
|---|---|---|---|
| Coal | 144,494,057 | 143,429,323 | (1) |
| Combined Cycle | 26,615,595 | 31,998,701 | 20 |
| Combustion Turbine | 3,937,201 | 4,557,548 | 16 |
| Steam Gas | 18,386,127 | 19,131,319 | 4 |
| Oil-fired and Other | 2,854,579 | 3,190,984 | 12 |
| Pumped Storage | 390,142 | 411,053 | 5 |
| **SPP Total** | **196,677,701** | **202,718,927** | **3** |

**Table 2-2 Generation Benchmark Comparison by Market Participant**

| Market Participant | Actual Generation | PROMOD IV Generation | Deviation (%) |
|---|---|---|---|
| American Electric Power (formerly CSWS) | 41,962,732 | 41,182,762 | (2) |
| Arkansas Electric Cooperative Company | 1,795,172 | 1,851,710 | 3 |
| Empire District Electric | 3,579,993 | 3,756,916 | 5 |
| KCP&L Greater Missouri Operating Company | 8,279,723 | 9,289,162 | 12 |
| Grand River Dam Authority | 6,961,510 | 7,388,326 | 6 |
| Kansas City Board of Public Utilities | 2,884,154 | 3,015,250 | 5 |
| Kansas City Power & Light | 20,437,311 | 21,407,834 | 5 |
| Lincoln Electric System | 3,340,817 | 3,375,408 | 1 |
| Nebraska Public Power District | 13,057,944 | 12,660,130 | (3) |
| Oklahoma Gas & Electric Company | 29,201,781 | 32,382,533 | 11 |
| Oklahoma Municipal Power Authority | 1,288,968 | 1,659,420 | 29 |
| Omaha Public Power District | 12,003,191 | 12,775,970 | 6 |
| Sunflower Electric Power Corporation | 2,957,545 | 2,736,305 | (7) |
| Southwestern Public Service Company | 25,908,120 | 25,937,926 | 0 |
| Western Farmers Electric Cooperative | 4,716,482 | 4,665,303 | (1) |
| Mid-Kansas Electric Network | 667,190 | 677,496 | 2 |
| Westar Energy | 31,293,963 | 32,646,356 | 4 |
| **Total** | **210,336,596** | **217,408,807** | **3%** |

## 2.1.2 Economic Threshold

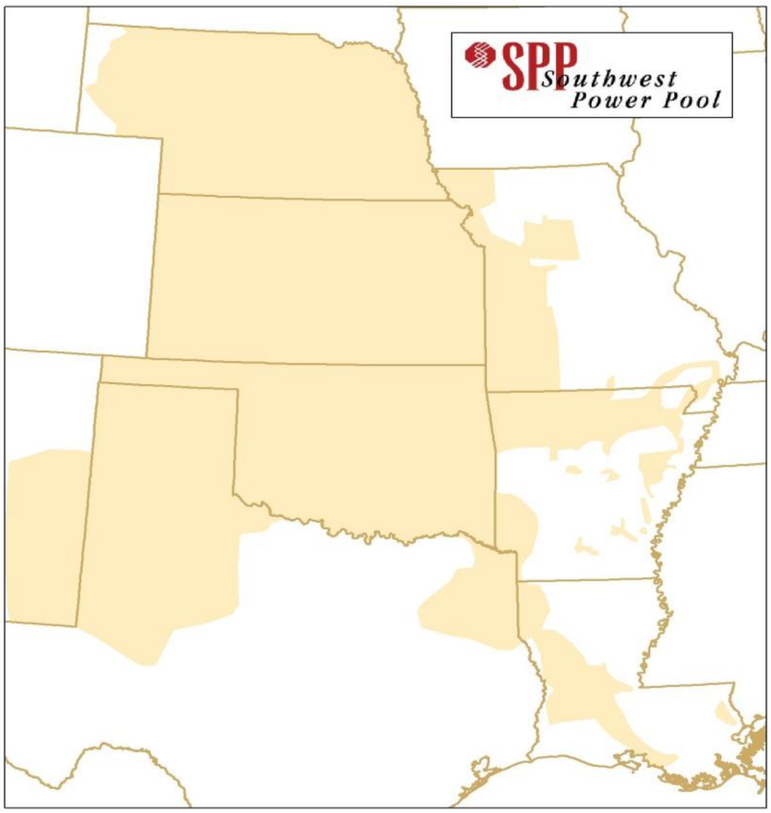
A key aspect of the benchmark effort was the development of an “economic threshold” representing a barrier to economic interchange between Balancing Areas in SPP. These economic thresholds represent the minimum price differential between two areas that must occur before interchange between the pools will be impeded. These thresholds typically include a component to represent any through-and-out transmission tariffs plus a “scheduling inefficiency” factor. For SPP Balancing Areas separate economic thresholds were developed for commitment and dispatch to capture the inefficiencies of current SPP EIS operations without a Centralized DA unit commitment process.

Following the benchmark to the historical market, the model was run for the full study horizon 2009 through 2016 to provide a base case for market operations. This base case represents the current SPP EIS market, the 2008 Q2 SPP Transmission Expansion Plan (STEP) projects, and the 2008 Nebraska and GMOC Transmission Expansion Plans. In this case, the transmission and resource topology for SPP include only those upgrades planned as part of the STEP. Economic threshold for commitment and unit dispatch adjustment factors were carried forward where applicable from the benchmarking run to impose consistency between past and future unit operation.

### 2.1.3 Development of Model Base Case

As part of the Base Case model of the current SPP EIS market out to 2016, some modeling issues were discussed and established including determination of which markets to include in the simulation ("study footprint"), development of a generation expansion plan for the entire study footprint, transmission grid expansion, incorporation of likely market trends, such as new wind penetration, demand response program penetration ("smart grid"), and joint market coordination. The SPP Footprint is shown in Figure 2-1.

**Figure 2-1 SPP Footprint**




The study footprint was extended to most of the Eastern Interconnect including SPP, PJM, MISO, Entergy, TVA, and non-MISO Market Participants of MRO. Decisions were made as to new wind penetration, joint coordination, and demand response modeling as described in section 3.

Ventyx developed a unit expansion plan based on economic and target reliability criteria. Ventyx's proprietary MarketPower® software was used to develop forecasts of capacity value. Using a twelve-month look-ahead, MarketPower makes economic based decisions related to the addition of new units, the retiring or mothballing of existing units, and the repowering of mothballed units. Specifications for new unit additions (called prototypes) are user-defined and include descriptions of capital costs, economic life and rate of return.

The unit expansion plan developed with the base case was also used across all market design scenarios. This process did not result in the addition of any resources, beyond those included in the 2008 Q2 STEP, within the SPP Market footprint for term of the study.

Another key effort associated with the development of the study base case was the implementation of year by year transmission powerflow changes based on the 2008 STEP. Analyzing differences in transmission system operations requires a model such as PROMOD IV that captures the integration of transmission operations with generation unit commitment and dispatch. The PROMOD model used in this analysis provides a detailed representation of transmission and generation in the Eastern Interconnect including more than 40,000 transmission buses, 50,000 transmission lines, and 5,000 generating units. Using hourly load and generation inputs, PROMOD IV models a security-constrained, chronological unit commitment and hour-by-hour dispatch of generation. Each study year used a powerflow case provided by SPP with topology based on the STEP upgrade schedule. This approach required significant effort to map PROMOD IV load and generation for each year and to perform contingency analysis for all years to ensure that changes in the congestion patterns were captured. By using an extended study footprint, the model fully captured the dynamics of regional interchange based on available transmission capacity and the economics of regional power costs.

Fourteen balancing authorities (BAs) were modeled. Commitment was designated at the BA level, with economic dispatch of SPP resources. Security regions and operating directives as needed were modeled to consider commitment for system security and reliability. Spinning reserve requirements and regulation-up requirements were set at the BA level. Additionally, generators owned by IPPs and non-primary BA market participants were not allowed to contribute to the spinning reserve and regulation-up requirements, to better replicate EIS market operations.

### 2.1.4 Study Metrics

Costs and benefits of alternative market structures can be measured in various ways, including net system production costs, demand and supply costs, and the incidence of generation cost and revenues. Energy supply costs were measured and presented in several forms.

The following options were considered as measures of supply costs:

- Adjusted production costs, a standard measure of supply costs, is composed of generation variable costs adjusted by costs and revenues of energy bought from and sold to the market, with purchases priced at the entity's load LMP and sales priced at the entity's average generation LMP, and, if an Ancillary Services Market (ASM) is functional, including payments and revenues associated with the Ancillary Service products.

- Market value of energy used to meet customer requirements, an alternate measure of the cost of serving load, is calculated as the balancing area hourly demand multiplied by the load-weighted hourly LMPs for the balancing area.

- Generator utilization, costs and revenues, including both energy revenues and ancillary services spinning reserve revenues is another useful measure.

Ventyx and SPP agreed to use adjusted production cost to quantify the benefit of future market designs. At the SPP level, adjusted production cost in each hour is defined as variable generation costs less the market value of exports to entities outside SPP plus the market value of imports from entities outside SPP. Firm purchase power agreements and power sales (PPAs) were included as load adjustments for the time periods identified by the SPP Members.

**Adjusted Production Cost**

i = Hour

- If $\sum \text{Generation}_i > \text{Load}_i$ then

  $APC_i = \sum \text{Variable Generation Cost}_i - (\sum \text{Generation}_i - \text{Load}_i)(\text{Generation Weighted Hub Price}_i)$

- If $\sum \text{Generation}_i < \text{Load}_i$ then

  $APC_i = \sum \text{Variable Generation Cost}_i + (\text{Load}_i - \sum \text{Generation}_i)(\text{Load Weighted Hub Price}_i)$

**Gross Benefit**

- Gross Benefit = Base Case Annual Adjusted Production Cost – Change Case Annual Adjusted Production Cost

**Net Benefit**

- Net Benefit = Gross Benefit – Cost

For market participants, balancing authorities, and states, the formula for adjusted production cost involves net purchases and sales (as opposed to net imports or net exports); net purchases are still valued at the load-weighted hub price, and net sales at the generation-weighted hub price. In addition, at these levels (but not for SPP as a whole), and only for Change Cases II and III, adjusted production costs includes revenues from sales of ancillary services (subtracted) and costs associated with purchases of ancillary services (added).

Adjusted production costs were computed hourly and aggregated into annual costs for SPP Market total, and for several sub-segments of the SPP market. The gross benefits (or operational benefits) derived from a given market design would be the difference between annual adjusted production cost of the Base Case (EIS market) less the annual adjusted production cost of the Change Case for either SPP or a market segment. Ventyx and SPP recognize that this approach focuses on the benefit of the whole, acknowledging the implication that there may be both positive and negative benefits in various magnitudes, according to the location of the various pricing nodes. Ventyx also provided adjusted production cost results for each state, balancing area, and Market Participant in SPP, thus providing a view of the distribution of gross benefits across segments.

Firm purchase power agreements and power sales (PPAs) were included as load adjustments and have the effect of reducing market purchases and/or increasing market sales. The source and sink of each PPA was identified so that the PPA energy could be incorporated into the SPP (if either source or sink was outside SPP market), and all appropriate market segments. Since the firm PPAs' energy is constant in all Cases, there was not need to consider the associated cost or revenue as the costs would net to zero in the benefit calculations.

For determination of market design benefit for a state, nodes (buses) were identified by state location such that state's aggregate load could be calculated. A generator's output and Ancillary Service contribution were assigned to a state based on its location regardless of ownership. PPAs which cross a state line were included; PPAs totally within a state were not. Ancillary Service requirements of the market participants were divided among the states proportional to the market participants' responsibility for state load. For example, if 40% of a particular Market Participant's load was located in Kansas, then 40% of that Market Participant's AS requirement was allocated to Kansas.

For determination of market design benefit for a Market Participant, nodes (buses) were identified by the Member responsible for the demand at that node. A generator's energy output, variable costs, and Ancillary Service contribution were assigned to Members based on ownership. Output, variable costs, and AS contribution of a jointly-owned generator was divided to all owners based on fixed owner ratios. PPAs of each Market Participant were included. Ancillary Service requirements were provided for each market participant.

Load, generation, Ancillary Service requirements and contribution, and PPAs were treated similarly at the Balancing Authority level.

### 2.1.5 Modeling of Market Design Cases

In conducting this SPP RTO Cost Benefit analysis, Ventyx used its own PROMOD IV® nodal chronological production costing and power flow software model, as well as its MarketVision™ database, with study-appropriate enhancements, for the detailed market simulations. PROMOD IV incorporates accurate day-ahead scheduling, commitment and dispatch of all three market models (i.e. MISO, SPP and an SPP stand-alone market model), in addition to accurate LMP calculations including both transmission congestion and marginal losses components, and future market developments such as an ancillary service spinning reserve market. The simulation procedure performed a detailed, security-constrained dispatch with nodal (bus-level) locational marginal prices and centralized, security-constrained dispatch. For the current EIS market, each Balancing Authority (BA) was modeled with local commitment criteria, BA-to-BA economic thresholds, and unit dispatch adjustment factors to capture self-commitment and current unit operations. Each SPP BA was required to carry its own spinning reserves based on their allocation of the SPP Reserve Sharing Group requirement plus an estimated regulation component of 1% of the load. Projected average losses were modeled in input load requirements, with no marginal loss components included in locational marginal prices. The real time EIS market dispatch was reflected in the PROMOD IV solution including BA purchases to serve load and sales of excess BA generation based on market opportunities. In modeling the future market designs, the representation of the SPP commitment, dispatch and reserve rules were changed to reflect different elements of each specific market design.

PROMOD IV is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, 8760 hourly transmission constraints assessment, generation analysis, unit commitment/operating conditions, and market system operations. For over 25 years, energy firms have been using PROMOD IV for a variety of applications that include locational marginal price (LMP) forecasting, financial transmission right (FTR) valuation, environmental analysis, asset evaluations (generation and transmission), generating unit operating strategy evaluation, zonal and hub market price forecasting, transmission congestion analysis, generating unit option valuation, bid analysis, purchased power agreement evaluations, and resource mix assessment for companies with load obligations.

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PROMOD IV performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, bus-bar and zonal energy market prices, external market transactions, transmission flows and congestion prices. The heart of PROMOD IV is an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints; including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand.

#### 2.1.5.1 Change Case I - Day-Ahead Market with Unit Commitment Additional Only

Ventyx developed a change case model to assess adding to the base case a multi-settlement energy market without an ancillary services market. This case features a Day-Ahead Market with Centralized Unit Commitment as well as the real time EIS market dispatch. This case was implemented by removing internal economic thresholds between SPP BAs, and adjusting unit dispatch factors to be closer to a purely economic dispatch than in the base case data to create a single, centralized, commitment and dispatch market. These adjustments to the generator dispatch factors were implemented to recognize that generation owners would be more likely to participant in the open, competitive market of a centralized unit commitment than the current EIS market. However, some market inefficiencies would probably still continue due to imperfect market information and human behavior. In order to recognize this increased market participation but maintain a conservative modeling approach, generator dispatch factors were relaxed but not removed entirely. Spinning reserves and regulation-up reserves were still met at the BA level based on the same allocation of the SPP Reserve Sharing Group requirement to each balancing area plus the additional regulation component, as modeled in the EIS base case. As in the Base Case model, generators owned by IPPs and non-primary BA market participants were not allowed to contribute to the spinning reserve and regulation-up requirements, to better replicate separate BA AS operations. Economic thresholds between SPP and other markets were relaxed also to implement future increased coordination. Simulation runs were performed for each year beginning January 2009 through December 2013, making the necessary adjustments to the base case data for each corresponding year. Since total benefit comparison required all eight years of gross benefits, Change Case I adjusted production costs for the years 2014 – 2016 were extrapolated based on the change in adjusted production cost of the Change Case II from year to year. The DAM nodal market simulation provides transmission congestion mitigation and day-ahead commitment through Locational Marginal Price based dispatch.

#### 2.1.5.2 Change Case IIA - Day-Ahead Market with Unit Commitment and Co-optimized Ancillary Service Market (All Inclusive) 2011-2016

Ventyx developed a change case model to assess an “all inclusive” multi-settlement energy market with an Ancillary Services Market. This case features a Day-Ahead Market with Centralized Unit Commitment and a fully Co-optimized Ancillary Services Market in addition to the real time EIS market. This case was implemented by:

- As in Change Case I, removing internal economic thresholds between SPP BAs, and adjusting unit dispatch adjustment factors from the base case creating a single, centralized commitment and dispatch market. Economic threshold rates between SPP and other markets were relaxed, again to the same levels as in Change Case I.

- The fourteen BAs’ spinning reserve and regulation-up requirements were aggregated into a single SPP spinning reserve requirement that could now be met with SPP generators located anywhere in the SPP system. That is, instead of needing to meet the apportioned spinning reserve requirement in each of the fourteen BAs (as in the Base Case and Change Case I), only one aggregate spinning reserve requirement had to be met. Additionally, generators owned by IPPs and other market participants which can physically provide spinning reserves were allowed to contribute to the Ancillary Service, under the assumption that the Ancillary Service Market would encourage broader participation then current rules.

Simulation runs were performed for each year beginning January 2011 through December 2016, making the necessary adjustments to the base case data for each corresponding year. The DAM nodal market simulation provides transmission congestion mitigation and next day commitment through Locational Marginal Price based dispatch.

Since AS payments and revenues balance at the SPP level, SPP benefits will not be affected by AS prices. For the adjusted production cost metric of a market segment, both generator energy output and contribution to the supply of ancillary services were incorporated. Since SPP has no history with an Ancillary Services Market, benchmarking could not be performed for AS prices. Additionally, AS prices will depend on market rules and participation. As such, an AS price of $15/MWh for SPP was assumed. The difference between the market segments' ancillary service requirement and its AS supply was priced at this assumed AS price. To provide a better understanding of the impact of AS pricing on market segment benefits, benefits for each State in 2012 were also developed under two sensitivities – a low AS price ($5/MWh) and a high AS price ($25/MWh). It is important to note that only the AS prices were changed in the sensitivity tests; commitment and dispatch were not affected so the distribution of AS provided across generators remained the same.

#### 2.1.5.3 Change Case IIB - Staged Implementation, Day-Ahead Market with Unit Commitment 2009-2010 and All Inclusive Market 2011-2016

Recognizing the implementation of market design and rules changes require advance planning and execution of processes and procedures, this market design option involves a phased-in approach to the implementation of an "all inclusive" multi-settlement energy market with a Co-optimized Ancillary Services Market. The market design envisions an early implementation of a Day-Ahead Market with unit commitment for two years, followed by an "all inclusive" multi-settlement energy market with a Co-optimized Ancillary Services Market. The Day-Ahead Market with unit commitment would be operational for 2009 and 2010, switching to the "all inclusive" multi-settlement energy/AS market starting in 2011 and assessed through 2016. Thus, adjusted production costs for all segments and for SPP from Change Case I for the years 2009 and 2010 were combined with the adjusted production costs for all segments and for SPP from Change Case II for the years 2011 through 2016.

#### 2.1.5.4 Change Case IIC – Staged Implementation, Ancillary Services Market 2009-2010 with All Inclusive Market 2011-2016

Again, recognizing the implementation of market design and rules changes require advance planning and execution of processes and procedures, this market design option involves a phased-in approach to the implementation of an "all inclusive" multi-settlement energy market with a Co-optimized Ancillary Services Market. However, this market design envisions an early implementation of an Ancillary Services Market for two years, followed by an "all inclusive" multi-settlement energy market with a Co-optimized Ancillary Services Market. The Ancillary Services Market would be developed for 2009 and 2010, replaced by the "all inclusive" multi-settlement energy/AS market starting in 2011 and assessed through

2016. Thus, adjusted production costs for all segments and for SPP from Change Case III for the years 2009 and 2010 were combined with the adjusted production costs for all segments and for SPP from Change Case II for the years 2011 through 2016.

#### 2.1.5.5 Change Case III – Ancillary Services Market Only

Ventyx developed a change case model to assess adding an Ancillary Services Market only without a Day-Ahead Market and centralized unit commitment. This case features an ancillary services market added to the current real time EIS market dispatch. This case was implemented by creating a single ancillary services requirement that can be met by generation located anywhere in the SPP system, and all generators which can supply spinning reserve were allowed regardless of owner. Simulation runs were performed for each year beginning January 2009 through December 2013, making the necessary adjustments to the base case data for each corresponding year. In order to have a comparable set of benefits for evaluation over all years, adjusted production costs were extrapolated for the years 2014 – 2016 based on the APC change of the base case from year to year.

#### 2.1.5.6 Change Case IV – Simplified Day-Ahead Market with Unit Commitment

Change Case IV represents based on a simplified approach to a Day-Ahead Market with limited additional features. This market design is very close in structure to the current EIS market with the addition of the centralized unit commitment aspects for a more robust DAM, but would not allow virtual bids and offers, dispatchable schedules, or up to congestion schedules. This approach requires transmission service reservations and evaluation of AFC, including internal non-firm transactions. Scheduled amounts would continue to provide both the energy cost hedge and the congestion hedge, and curtailment would affect both components. This approach allows non-firm reservations, assuming they remain in place, to be a congestion hedge. Simultaneous feasibility would be assessed, including non-firm schedules, and curtailments performed on a priority basis the same as it occurs today. Schedules, firm and non-firm, may be curtailed from the DA levels in order to achieve RT feasibility, even if feasible in the DA clearing process. The resulting deviation in schedule between DA and RT would expose the source and sink to real time LMPs for Deviation. In this design, AFC/ATC would still be required to be assessed on all reservations requests, even for transactions wholly within the market footprint.

Since there are many unknown factors in both the specific market design, implementation, and level of participation in the type of market envisioned by Change Case IV, Ventyx, with SPP's approval, approached Change Case IV by means of a qualitative discussion of the implications and considerations associated with this market design. However, no explicit modeling or quantitative analysis of Change Case IV market was performed.

## 2.2 Cost Development Methodology

The primary objective of the cost development effort was to estimate the expenses associated with implementing and operating the different market design changes. The cost estimates were developed from two perspectives – from that of SPP and from that of its Market Participants. Typical cost components associated with changes to the design and operations of a market include organizational (staffing) increases, hardware and software system additions and upgrades, as well as other additional infrastructure for supporting increased requirements for market operations, customer services, training, planning, and documentation, legal and regulatory services. Note that these costs are different from the production cost estimates developed from the market modeling exercise.

### 2.2.1 SPP Cost Development Methodology

The approach for estimating SPP's costs to implement and operate the different market design cases was to integrate SPP departments' cost forecasts with cost data from other ISOs. The following SPP functional groups were identified to be included in the initial information gathering sessions:

- Operations (including market operations, tariff administration, scheduling, reliability coordination, operations engineering)
- Market Monitor
- Settlement
- Transmission Planning
- IT
- Reliability and Compliance
- Regulatory and Legal
- Project Management
- Training

Questionnaires were completed by selected Market Participant functional groups. They were asked to describe their group's current roles and responsibilities and any potential impact of each market change case on their group's capital and operating expenses. They were also asked to comment on their forecasted plans for changes in their group not including any changes to the market design. Starting from SPP's current forecasted capital and operating budget, the information from the different departments was considered in applying scaling factors to estimate budget requirements for each market change case.

Information from the different functional groups was also useful in framing the questions and discussions with other ISOs. Questionnaires similar to the ones developed for SPP, were developed for the different ISOs in order to gather information on their experiences with implementing design changes in their own markets. Responses to these questionnaires were gathered and documented through face-to-face interviews and conference calls with representatives of various functional groups within the ISOs. The objectives for these meetings with the ISOs were:

- To understand organization structure and roles and responsibilities.
- To identify any major differences between SPP's functional groups' structure and responsibilities and those of other ISOs.
- To understand how past market changes impacted functional groups in terms of staffing, processes, systems and changes in responsibilities.
- To gather lessons learned and identify any potential challenges.
- To gather additional insights into market design issues.

Cost and budget data from several ISOs were also obtained either through ISO and PUC websites or by requesting the documents from the ISO's customer service department.

This cost information, together with findings from meetings with ISOs, was presented back to the SPP functional groups. The different groups were asked to take the ISO data into consideration in estimating capital and operating costs for their departments as a result of the different market change cases.

### 2.2.2 Cost Estimates for SPP

The cost analysis incorporates the annual staff, software, hardware and training needed to successfully transition to the new market. The cost analysis also assumes that staffing remains constant after the second full year of operation, e.g., for Change Cases I and III, staffing is the same in all years 2010 – 2016, and for Change Case IIA, staffing is the same in all years 2012 – 2016. Software costs were obtained through discussions with several vendors and include annual maintenance expense.

### 2.2.3 Cost Estimates for SPP Market Participants

Just as SPP is expected to incur additional expenses due to the changes in the market design, each SPP Market Participant is also expected to implement changes in its staffing levels as well as software and hardware systems. SPP market participants vary in terms of size (as measured by generation capacity and load served) and level of sophistication with regard to market systems and processes. For example, some Market Participants already participate in other markets with features similar to what SPP is considering, e.g., PJM's Day-Ahead Market. To remove inconsistencies in assumptions and forecasting across individual Market Participants, categories were defined for "Small" and "Large" participants and for "Simple" and "Complex" participants. A representative range of costs was developed for each Market Participant category. The general definitions underlying these categories characteristics were

- Small Market Participant is defined as less than 1000 MW.

- Simple Market Participant is defined as having only hydro and/or nuclear generation with straightforward PPA; Complex Market Participant is defined as having coal, gas, and/or wind generation with compound PPA, essentially anything mid-merit (i.e., a unit that does not run all hours it is available, or at full capacity all hours that it does run).

Just as with ISO interviews, questionnaires were developed and addressed to the different market participant functional groups. The following functional groups were identified:

- Trading Operations
- Risk Controls
- Settlement
- IT
- Regulatory and Legal
- Project Management
- Training

The questionnaires were followed up with conference calls in order to gather and document Market Participants' responses. The different change cases were explained to market participants and they were asked to provide their views on the potential impact of each market change case on their functional groups' responsibilities and expenses. The information gathered from Market Participants at opposite ends of the "size" spectrum was then used to estimate a potential range of costs for Market Participants' participation in the market change cases.

The estimated costs required for participation in the future market design scenarios were based on the need for systems infrastructure and staffing that varied based on the size, mix, and complexity of participant's operations including generation assets and Power Purchase Agreements (PPA). The following infrastructure systems formed the basis for future design market participation:

- (AGC) – Automatic Generation Control (AGC) for remote dispatch

- Bid Strategy – Short term load and System Marginal Price (SMP) forecasts to support bidding strategy

- Unit Commitment – Unit commitment based on optimization algorithms

- RTO Communications – Market communications with RTO

- Settlement – Compare downloaded RTO settlement statements against statements using market charge components with participant data

- FTR/TSR Analysis – Financial Transmission Rights/Transmission Service Rights analysis

The following table shows assumptions for required infrastructure systems across the study scenarios.

**Table 2-3 MP Systems Infrastructure**

| MP Systems Infrastructure | Change Case | | | |
|---|---|---|---|---|
| | I | II | III | IV |
| AGC | X | X | X | X |
| Unit Commitment | X | X | | X |
| Bid Strategy | X | X | X | X |
| ISO Communications | X | X | X | X |
| Settlement | X | X | X | X |
| FTR/TSR Analysis | X | X | | |

# 3 Data Assumptions

Producing quality strategic and operational economic analysis requires comprehensive, state-of-the-art software models, and high-quality industry data. Ventyx has developed its own MarketVision® Market Data containing detailed industry data that can be used independently for custom analysis or incorporated into studies using the Ventyx PowerBase™ suite of planning software - MarketPower®, Strategist® and PROMOD IV®. The quantitative economic benefit analysis combined the Ventyx MarketVision database and SPP specific data, along with customized modeling parameters developed during and for this study, as input into the Ventyx simulation software PROMOD IV and MarketPower. This section describes the input data assumptions for the simulation software. Unless directly noted, the data assumptions are those of Ventyx. MarketVision Market Data contains United States and Canadian electric utility data including:

- Existing and planned generating unit operational characteristics such as capacity, heat rate curves, O&M costs, primary and secondary fuels, emissions rates, maintenance requirements, outage rates and durations, startup costs, and ramp rates
- Forecasted monthly regional fuel and emissions allowance prices
- Hourly demand shapes with forecasted peak and energy, and interruptible load capacity
- Regional zonal transmission constraints and tariffs
- Generator and area bus mappings
- Event files which include monitored branches, DC ties, and NERC flowgates for interfaces and contingencies.
- Generator and area bus mappings
- Monitored branches, DC ties, and NERC flowgates for interfaces and contingencies

Full power flow transmission data was utilized for the Eastern Interconnect (MMWG cases[3]). This data includes:

- Data for buses, transmission lines, transformers, real bus load, real shunt admittance, and phase angle regulators [based on the NERC Multi-regional Modeling Working Group (MMWG) transmission cases for reliability and stability studies]

[3] MMWG stands for the NERC Multiregional Modeling Working Group, which is responsible for assembling power flow and dynamic models for the Eastern Interconnection for reliability studies and stability studies.

## 3.1 Generating Units

The model requires significant detailed data about existing fossil fuel-fired units, hydro-electric generation and potential new generating units.

### 3.1.1 Existing Fossil Units

The majority of the generating unit information in the database is derived using data from the Energy Impact Assessment (EIA) 906 forms and the FERC Form 1. The generator capacity information required to estimate capacity factors and fixed costs are derived from EIA 860 existing and planned generator data, NERC ES&D 411, EIA 906, as well as original research conducted by Ventyx, SPP and CBTF. Below is a brief description of each data source. Additionally, the SPP Market Participants reviewed the Ventyx generator data assumptions. The Market Participants provided more precise generator characteristics to improve the analysis. This non-public Market Participant-specific data is confidential and is not included in any table or any part of this document. SPP also provided information regarding jointly-owned generators, which was incorporated into the analysis.

- **EIA FORM 906 -** The basis for our monthly plant generation and consumption is the EIA form 906, a collection of information from all regulated and unregulated electric power plants and combined heat and power (CHP) facilities in the United States. The EIA form 906 is provided in annual and monthly versions. The primary components of the 906 form are electric power generation, fuel consumption, fuel heat content, fossil fuel stocks, and thermal output (non-electric) at combined heat and power plants. In estimating O&M costs we use the generation data from this form. The monthly Form EIA-906 is a sample of electric power plants and combined heat and power facilities that report the same information found on the annual report. Electric power plants and combined heat and power facilities that are not selected to respond monthly must file annually on this form. The requirements for reporting this form changed recently and now only power plants with generating capacity of over 50 megawatts (MW) are required to file if selected to report on a monthly basis. A random sample of plants under 50MW is also selected to ensure statistical significance. The data is continually proofed against other sources of information to check for errors. The most common error in this data occurs when a respondent mislabels their units of generation (in megawatts instead of kilowatts or vice versa).

- **FERC FORM 1 -** The FERC Form 1 is an annual collection of operational and financial information reported by utilities and entities that are required to report to the FERC. According to the FERC, those entities that are required to report must have in each of the three previous calendar years, sales or transmission service that exceeds one of the following:
    - One million megawatt hours of total annual sales
    - 100 megawatt hours of annual sales for resale
    - 500 megawatt hours of annual power exchanges delivered

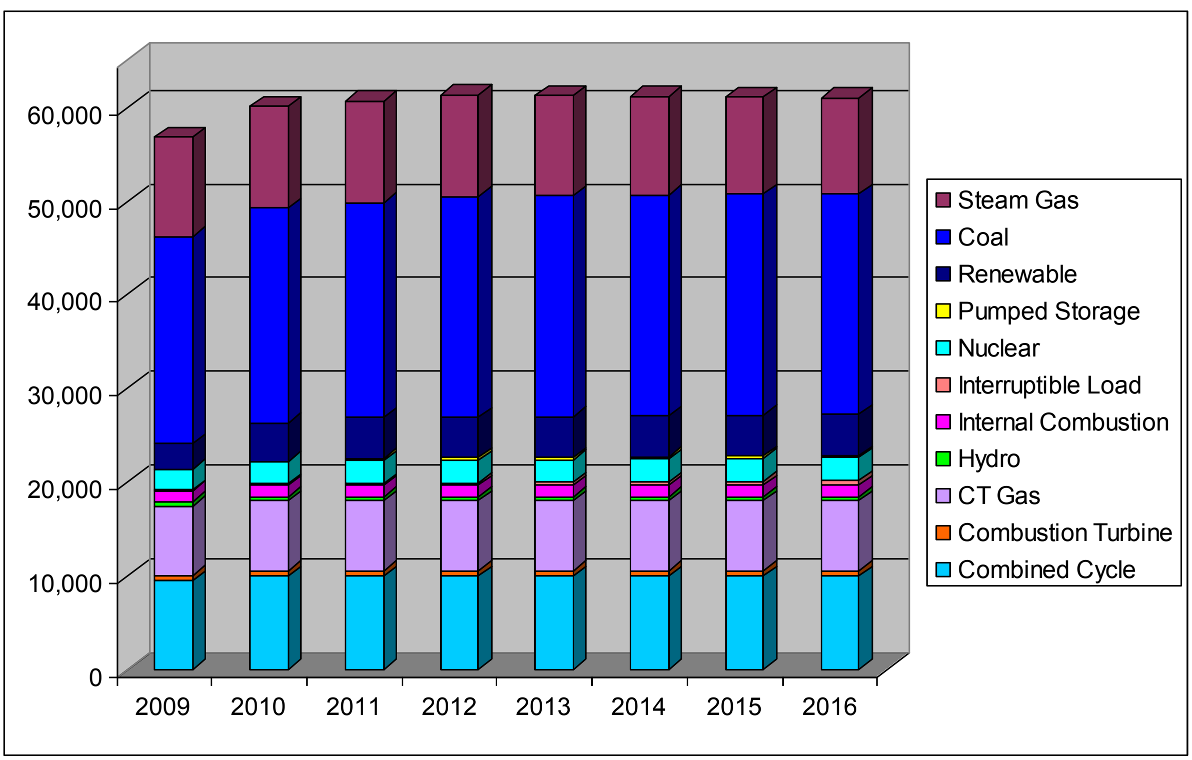
- 500 megawatt hours of annual wheeling for others (deliveries plus losses)

The FERC Form 1 data is downloaded into our database in 'raw' form, but proofed for outliers and inconsistencies. The form information used to develop O&M cost estimates are reported on pages 402-410 on the Form 1, commonly referred to as the generating plant or plant cost section. This section details the yearly physical and the financial operation and generation of the plants owned/operated by the reporting company. Once the data is compiled into our database it is proofed again to correct for reporting errors not captured by the FERC. For the portions of the plant that are owned by entities not required to report to Form 1, we have created our own cost records for these entities according to the portion of the plant that is owned by the missing owner and the total costs/capacity/generation of the plant.

- **EIA FORM 860 -** The EIA form 860 is an annual report comprised of existing and planned electric generating plants and their associated units for the United States. The secondary source for generating unit capacity is the NERC form 411.

Figure 3-1 summarizes the changes in maximum capacity of generating units in SPP. The figure illustrates the importance of coal-fired steam generation in SPP, as more than half of the capacity in the region falls in this category. Renewable resources and nuclear together account for another quarter of the capacity. Gas-fired combined cycle and simple cycle combustion turbines, hydro, internal combustion, and interruptible loads together constitute less than one-quarter of the capacity in the region.

**Figure 3-1 SPP Installed Capacity by Type (MW)**



### 3.1.2 Monthly Hydro Energy

The monthly hydro energies for the new SPP entrants (i.e., the Nebraska utilities and GMOC) were taken from the Ventyx MarketVision database, representing monthly net energy production for 2006 for all U.S. hydro plants. This data is derived from EIA 920 data. The other SPP members that own hydro facilities supplied historical average energy production to be utilized for each forward year in the study. SPP supplied 2007 actual monthly energy output for its hydroelectric facilities for the benchmark case. Table 3-1 displays the average monthly energy produced at each of the fixed energy hydro facilities in SPP.

**Table 3-1 SPP Hydro Units Monthly Energy (GWh)**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Columbus (NE) | 4.34 | 9.62 | 14.34 | 14.34 | 11.38 | 12.21 | 8.84 | 12.22 | 10.34 | 15.98 | 13.59 | 2.06 |
| Ellis (AR) | 11.00 | 9.92 | 10.14 | 10.49 | 11.78 | 12.14 | 12.48 | 12.52 | 8.86 | 8.95 | 7.45 | 11.75 |
| Jeffrey | 3.23 | 3.13 | 4.40 | 4.48 | 4.85 | 7.92 | 12.39 | 7.98 | 2.29 | 2.77 | 2.59 | 2.86 |
| Johnson 1 | 2.59 | 2.59 | 3.83 | 3.89 | 2.91 | 4.78 | 5.62 | 2.76 | 0.18 | 2.03 | 1.79 | 2.26 |
| Johnson 2 | 3.26 | 3.26 | 4.84 | 4.89 | 3.57 | 5.80 | 6.34 | 3.03 | 0.14 | 2.21 | 2.22 | 2.82 |
| Kaw Hydro | 6.96 | 10.87 | 13.01 | 10.78 | 16.68 | 17.18 | 12.54 | 6.71 | 4.04 | 3.98 | 2.91 | 2.54 |
| Kerr - GRDA | 19.46 | 29.56 | 17.15 | 28.98 | 52.41 | 44.03 | 40.47 | 33.94 | 14.29 | 5.67 | 0.97 | 13.75 |
| Kingsley | 0.82 | - | - | 0.92 | 0.90 | 1.48 | 6.97 | 1.72 | 0.36 | - | - | 0.95 |
| Monroe (NE) | 0.96 | 1.96 | 2.17 | 2.10 | 2.02 | 2.10 | 2.12 | 2.17 | 1.57 | 2.17 | 2.10 | 0.48 |
| Narrows (AR) | 4.50 | 3.30 | 4.36 | 3.89 | 3.73 | 2.77 | 2.92 | 2.12 | 1.50 | 1.45 | 2.58 | 4.70 |
| North Platte | - | - | - | - | 1.54 | 4.68 | 13.16 | 8.52 | - | - | - | - |
| Ozark Beach | 5.82 | 7.29 | 4.98 | 4.75 | 5.77 | 8.33 | 6.31 | 7.73 | 4.09 | 2.49 | 1.47 | 4.40 |
| Pensacola | 35.05 | 62.99 | 39.55 | 65.18 | 88.50 | 82.51 | 76.58 | 63.08 | 31.29 | 11.56 | 3.79 | 25.14 |

### 3.1.3 New Entrants Generator Additions

Ventyx tracks the status of all proposed generation projects across North America. The NERC database includes those projects identified as being under construction or completed, plus additional planned generators that Ventyx considered to be highly likely based on their permitting status or on particular regulatory issues. Appendix F lists new generation in SPP scheduled to come on-line after 2008. During the study period, the following capacity was added to each category:

- CT – 332 MW
- CC – 529 MW
- Coal – 2,231 MW
- Internal Combustion – 76 MW

### 3.1.4 Renewable Build-out, Reliability and Economic Entry Resource Expansion

The Ventyx MarketPower regional capacity expansion software was utilized in this study to augment this generation expansion plan out to 2016. The projected SPP Reserve Margins from existing resources identified in section 3.1.1 did not fall below a level deemed necessary to include additional speculative resources within the Market area for this study. Therefore the additions as a result of the Ventyx expansion plan are restricted to areas outside of the SPP Market. Appendix F shows a list of generators added to each market to maintain target balance of load and generation. During the study period, the following speculative capacity was added to each market area:

- MISO – 3,680 MW
- MRO – 1,030 MW
- PJM – 920 MW

### 3.1.5 Wind Plant Modeling

All cases utilize the approved wind generation for interconnection that has not been suspended. This amounts to 4,211 MW of generation constructed prior to and during the study period of 2009 - 2011. This capacity generated energy equal to seven percent of SPP's 2011 load forecast for energy. The 2011 wind levels were maintained for the remaining years of the study due to concerns of deliverability without significant transmission expansion. Although there are significant numbers of wind projects in the Generation Interconnection Queue (GIQ), those that do not have Generation Interconnect Agreements in place would be speculative and require the CBTF to develop corresponding transmission expansion to incorporate them into the study. The CBTF and the MWG agreed that this study is not to assess the impact of wind penetration but to determine the benefits of moving to future phases of the market. The wind penetration will affect prices and congestion to a degree as well as regulation needs; however, by maintaining the same wind profiles for both the Base Cases and the Change Cases each year, the impact of wind to assessing the operational benefits of moving to the Centralized Unit Commitment is minimal. The levels of wind in the cases are reasonable for the level of transmission expansion included in the models and represent an increase in penetration from current levels.

For recently constructed and/or future wind plants that do not have an operating history, we assign default monthly capacity factor assumptions based on location. The default capacity factors are based on 2003-2006 weighted average capacity factors of all Wind Plants in each Wind Zone with on-line dates between 1/1/2001 and 1/1/2006 (prior to 2001 most wind farms are based on less productive wind technology than new projects).

SPP provided generic hourly wind patterns (i.e. a daily MW wind schedules for each month). These hourly wind patterns do not contain a volatility component and thus were never shut completely off or running at 100%. To determine the hourly schedule of an individual wind facility, this hourly wind schedule was adjusted using the wind plant's maximum capacity and monthly capacity factor. In a few cases, the SPP Market Participant supplied adjustments to the hourly profiles for specific resources to reflect a higher or lower capacity factor based on historical wind information.

Many of the future wind farms were placed into a separate Member for independent wind development, “Wind IPPs”. The purpose was to avoid perturbing the impact of the market structure cost benefit evaluation for current Members with the uncertainty of the wind development. Appendix G shows the SPP Wind Resource Additions.

## 3.2 Fuel Price Forecasts

Ventyx has a fuel price forecasting group which develops both short-term and long-term price forecasts for natural gas, heavy and light oil, coal and uranium. This forecasting group incorporates economic theory of supply and demand and other market factors into a fundamental forecasting model. They consider future demand requirements across the world and in North America. Additionally, future resources are considered in the context of developing technology and sources including LNG and oil shale both in North American and emerging global supply.

### 3.2.1 Coal Price Forecast

The Ventyx coal price forecast is derived from a proprietary modeling methodology that, for each coal-fired power-plant and boiler, finds the set of coals and transportation modes which most efficiently: satisfy electricity demand; meet requirements for BTU, Ash, $SO_2$, etc.; use existing long-term contract coal first; use spot coal as needed (to meet above requirements); take into account transport/trans-loader capacities; and internalize the cost of coal, transportation, and emissions allowance for $SO_2$, $NO_x$, and Hg.

Coal price forecasting includes fundamental North American coal supply and demand as well as global supply effects of imports. The prices are historical through March 2008. Subsequent prices are forecasted annually through 2016.

Coal generation provides the largest amount of generation during the study years. The annual average coal prices for the member companies ranges from $1.42/MMBtu in 2009 up to $1.65/MMBtu in 2016. The average annual increases in coal prices are approximately 2.2%. Individual site forecasts range price from $0.99/MMBtu to $2.31/MMBtu in 2009 and increase to $1.19/MMBtu and $2.41/MMBtu respectively in 2016.

### 3.2.2 Natural Gas Price Forecast

The Ventyx North American natural gas price forecast is comprised of short-term market prices and a long-term price forecast. Ventyx utilizes the near-term NYMEX prices into their forecast of the fundamental commodity price at Henry Hub.

Ventyx has its own gas price forecasting group devoted exclusively to the development of long-term price forecasts for natural gas based on fundamental modeling of North American gas supply and demand, as well as emerging global supply effects from growing LNG markets and international competition. This forecasting group incorporates economic theory of supply and demand and other market factors into a fundamental forecasting model. They consider future demand requirements across the world and in North America. Additionally, future resources are considered in the context of developing technology and sources including LNG and oil shale both in North American and emerging global supply.

The long-term natural gas supply forecast is developed using the GPCM® Natural Gas Market Forecasting System by RBAC, Inc. Ventyx develops a forecast of natural gas demand by state and by sector, i.e. residential, commercial, industrial, and electric. Electric generator demand is based on the Ventyx Reference Case®.

Currently, LNG is seen as a price taker (i.e. not marginal) and thus LNG cannot flood the market. Gas prices are forecasted to decline in 2013 due to increases in unconventional gas production including shale. Then gas prices will increase sharply in 2016 due to a high volume of electric sector usage from new gas-fired generators. Ventyx does not foresee increased gas production from Alaska until the 2018 – 2020 timeframe. Figures 3-2 and 3-3 display the forecast of natural gas prices.

**Figure 3-2 Annual Average Henry Hub Natural Gas Price Forecast ($/MMBtu)**

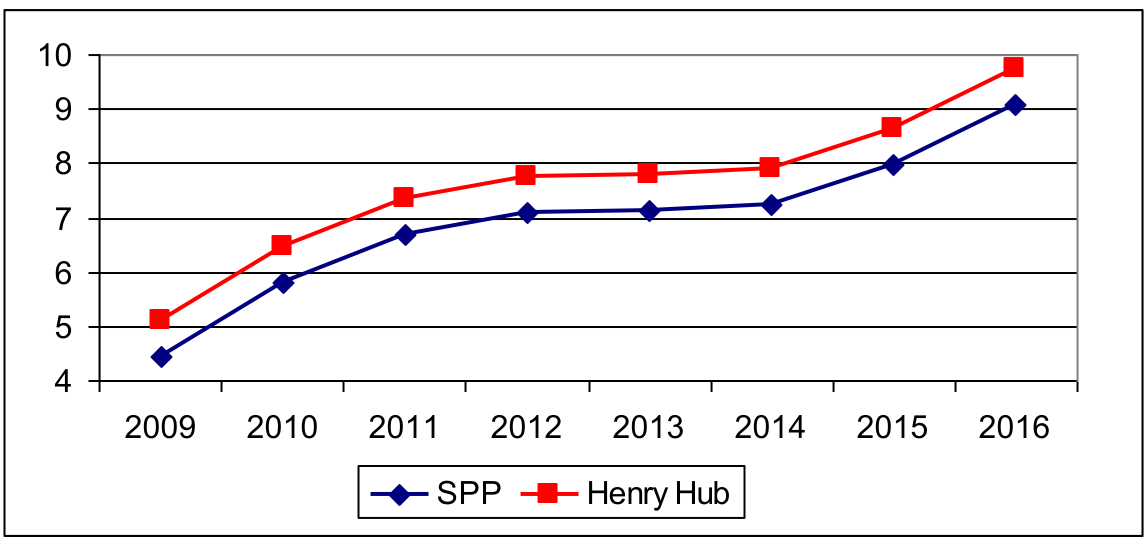
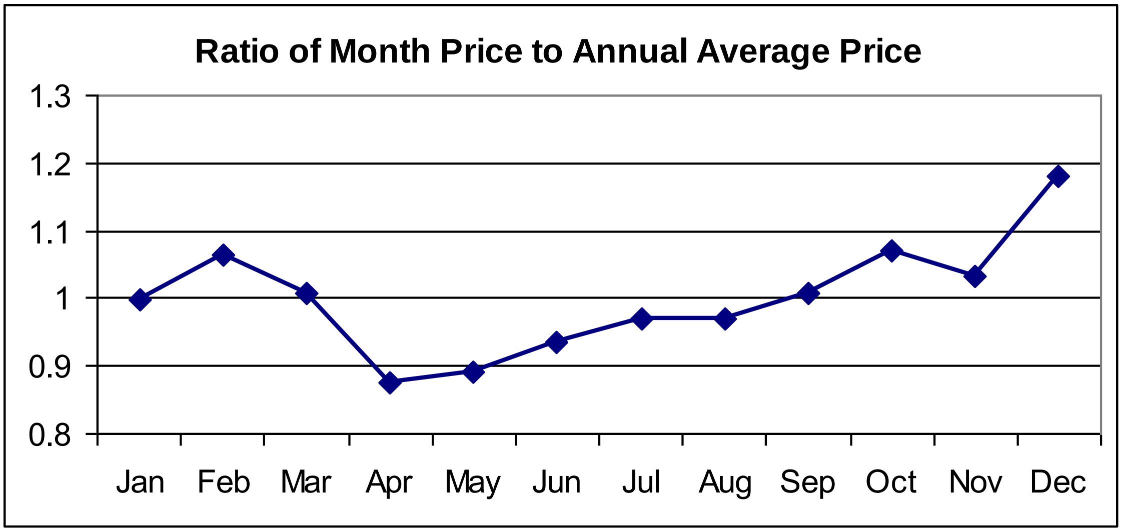


**Figure 3-3 SPP Natural Gas Prices - Monthly Price Pattern**




### 3.2.3 Oil Price Forecast

Ventyx utilizes a proprietary fundamental world oil forecasting model. The model forecasts: reserves, deliverability, supply cost, supply cushion, technology/reserve appreciation, and regional demand. The model tracks supply, production, reserves, and costs at twenty-four major oil producing countries/regions that are reviewed by Energy Velocity staff including a PhD Geologist. The model incorporates OPEC supply cartel behavior. Demand is forecast using GDP, prices, and other macro-drivers.

Full-cycle incremental production cost is modeled for twenty-four worldwide production regions. Separate treatment for OPEC and Non-OPEC production is explicitly modeled to account for cartel supply withholding that increases prices above competitive levels. World demand is disaggregated into regional demand.

Heavy and light oil prices for all regions were updated as of February 2, 2009. For this study, the heavy and light oil prices (#6 oil and #2 oil respectively) were adjusted monthly to be consistent with the study's assumptions regarding natural gas prices.

### 3.2.4 Uranium Price Forecast

The annual yellowcake spot market and long-term contract prices were evaluated separately, and a weighted-average price was calculated. In the Ventyx Advisors' Fuels team analysis, a seven-year peak price plateau for Uranium appears between 2009 and 2016 at approximately $1.0/MMBtu, with the two highest peaks in 2011 and 2013 at $1.15 and $1.17 /MMBtu, respectively. This broad price plateau is the result of offset yellowcake price components that involve spot prices (2009), contract prices (2013) and the percentage of spot contracts in the weighted-average price (2011-2012). During this price plateau period, the weighted-average price of yellowcake is the greatest single price component in the fuel cycle. The second most significant component, the enrichment cost (SWU), is approximately 1.5 times greater than the yellowcake price. After 2015, incremental mine production steadily reduces the cost for spot yellowcake and therefore the term contract price.

### 3.2.5 Emission Allowance Price Forecast

Emission allowance price forecasts are developed using Energy Velocity's Emissions Forecast Model (EFM). This model projects annual emissions costs for $SO_2$ and $NO_x$ emissions. The EFM is an economic model that acts as a system planner to achieve the lowest system-wide cost of complying with emission regulations. Inputs to EFM include individual generator characteristics and forecast generation, multiple generator classifications, emissions caps by year and/or season as applicable, pollution control equipment options (FGD, SCR, ACI), pollution control equipment costs and efficiencies, rate base cost recovery for some installations, and starting levels of banked allowances. Outputs from EFM are emission costs by year ($/ton), forecast emissions (tons/year, lbs/year), and forecast installations (FGD, SCR, ACI).

SPP Cost Benefit Task Force (CBTF) supplied a forecast for $CO_2$ and mercury (Hg) prices. The mercury prices were back-calculated from the average Hg emissions rate and average heat rate of SPP generators that emit mercury, such that the average adder to a generator's dispatch rate for Hg would be $0.5/MWh.

Table 3-2 summarizes the forecasts of emission allowance prices. Although the price in dollars per ton for $CO_2$ is the lowest of any of the pollutant allowances, the assumption about the $CO_2$ allowance price has the largest impact on the study results, because the tons emitted per MWh generated is much higher for $CO_2$ than any other pollutant. In particular, coal plants, which comprise more than half of the existing capacity in the SPP, emit nearly one ton of $CO_2$ per MWh generated, so a $10/ton allowance price (or tax) increases the variable cost of a coal generator by nearly $10 per MWh. The table shows that the $CO_2$ price is assumed to be zero through 2012, starts at $10/ton in 2013, and increases $1/ton per year after that.

**Table 3-2 Emission Allowance Prices ($/short-ton)**

| Pollutant | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| CAIR Annual $NO_X$ | 1,377 | 1,322 | 1,248 | 1,219 | 1,207 | 1,200 | 1,156 | 1,134 |
| CAIR Seasonal $NO_X$* | 580 | 743 | 952 | 1,219 | 1,207 | 1,200 | 1,156 | 1,134 |
| CAIR $SO_2$ | - | 473 | 467 | 460 | 442 | 433 | 416 | 400 |
| $CO_2$ | - | - | - | - | 10 | 11 | 12 | 13 |
| Mercury (Hg) | - | - | - | 24,621,753 | 24,621,753 | 24,621,753 | 24,621,753 | 24,621,753 |
| $NO_X$ | 1,097 | 1,170 | 1,244 | 1,244 | 1,244 | 1,244 | 1,196 | 1,172 |
| SIP $NO_X$ | - | - | - | - | - | - | - | - |
| $SO_2$ | 480 | 473 | 467 | 460 | 442 | 433 | 416 | 400 |

**CAIR Seasonal $NO_x$ rates apply only May - September months.*

## 3.3 Load Forecasts

The model requires forecasts of loads at each load zone for each of the hours in the study period. These forecasts were developed by combining historical hourly load shape data with forecasts of peak and energy.

### 3.3.1 Historical Hourly Loads

The database contains a synthesized hourly 8760 load shape for each area based on several years of historical hourly load data. The purpose of the synthesized load patterns is to incorporate diverse weather patterns over time. Much of this historical data was filed by utilities under the FERC 714 filing process beginning in July 2007. Also, additional hourly load data was obtained from several ISO websites or was provided directly by utilities. Hourly load data was compared to the FERC 714 load forecasts and to historical peak/energy data reported by the utilities. At times, errors and omissions in the 2006 load data were discovered. To resolve these issues, Ventyx analysts contacted a wide variety of organizations. The synthesized hourly load shapes are based on 2001 – 2006 historical actual loads by company.

In addition, to make it possible to simulate historical loads, the 2006 historical peak/energy values for Power Customers (Utilities and/or Zonal Loads) are included in the database. These values were often calculated directly from the hourly load data, but other sources were used where the load shape is only a “proxy” for a given Power Customer.

### 3.3.2 Peak Demand and Energy Forecasts

Load forecasts for all SPP power customers are based on the SPP 2007 EIA-411. West Plains Energy Kansas is reflected as becoming the Kansas Electric Network and a part of the Sunflower Electric control area.

Utility/Zonal load forecasts for the various Regions/Sub-regions of the NERC database are updated periodically (once or twice per year) depending on the availability of publicly available forecasts. The database reflects the most recent 2007 load forecasts that were not already captured in previous releases and that were available prior to the start of the Fall 2007 Reference Case process. Most of the associated 10-year load forecasts that are part of the 2006 FERC 714 filings were produced by individual utilities in the March-June 2007 timeframe. So, the “2006” FERC 714 load forecasts were the most recent available as of September 2007. Most of the publicly filed load forecasts are for 10-years only; although, a few are for more.

Peak Demand and Energy forecasts for utilities in SPP were updated based on the SPP 2007 EIA-411 report. Ventyx worked with several utilities to update the load forecasts to be consistent with historical loads and growth trends.

West Plains Energy Kansas was changed to Mid-Kansas Electric Network on April 1, 2007. The Aquila subsidiary West Plains Energy Kansas was purchased by the Mid-Kansas Electric

Company, which itself is owned by distribution cooperatives who also own and manage the Sunflower Electric Power Corporation (http://www.midkansaselectric.net/). The former West Plains Energy Kansas company/territory is now referred to as the Mid-Kansas Electric Network. In addition, rather than being its own control area (Balancing Authority), the Mid-Kansas Electric Network is now part of the Sunflower Electric (SECI) BA. This is reflected in the "Detailed" Topology in the database. At this time the Kansas Electric Network still has its own individual load forecast in the database, consistent with the SPP 2007 EIA-411 filing.

Table 3-3 summarizes the forecast of annual energy requirements for SPP and the nearby region. Table 3-4 provides a similar summary of the peak demand forecast. Between 2009 and 2016, the SPP energy requirement is forecast to grow 1.8% per year, and the peak demand is forecast to grow 1.6% per year.

**Table 3-3 Annual Energy Forecast (GWh)**

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| Midwest ISO | 604,870 | 613,381 | 621,581 | 630,605 | 639,242 | 648,297 | 657,954 | 666,456 |
| MRO | 87,722 | 98,232 | 99,507 | 100,569 | 101,493 | 102,443 | 103,558 | 104,484 |
| PJM Interconnect | 332,073 | 336,406 | 341,367 | 345,702 | 350,507 | 354,972 | 359,639 | 364,287 |
| Southeast | 413,817 | 418,091 | 420,765 | 425,547 | 431,353 | 438,720 | 446,228 | 452,637 |
| Southwest Power Pool | 206,082 | 209,560 | 213,599 | 217,501 | 220,976 | 225,630 | 229,797 | 233,671 |

**Table 3-4 Annual Coincident Peak Forecast (MW)**

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| Midwest ISO | 117,464 | 119,235 | 120,845 | 122,693 | 124,429 | 126,360 | 128,242 | 129,854 |
| MRO | 15,387 | 15,592 | 15,802 | 16,043 | 16,008 | 16,325 | 16,484 | 16,648 |
| PJM Interconnect | 62,317 | 63,104 | 64,013 | 64,786 | 65,711 | 66,573 | 67,434 | 68,268 |
| Southeast | 76,775 | 78,293 | 79,561 | 81,220 | 82,994 | 84,789 | 86,224 | 87,453 |
| Southwest Power Pool | 41,467 | 42,195 | 42,912 | 43,885 | 44,142 | 45,115 | 45,877 | 46,649 |

Table 3-5 and Table 3-6 provide similar information for the individual utilities that comprise the SPP.

Table 3-7 summarizes the 2009 monthly energy requirements for each utility. These monthly load patterns were used to develop monthly energy forecasts for each of the years 2010 - 2016.

Table 3-5 SPP Utilities Annual Peak Forecast (MW)

| Company | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| AECC | 874 | 890 | 905 | 921 | 937 | 953 | 969 | 984 |
| CSWS (AEPW) | 7,512 | 7,642 | 7,771 | 7,889 | 8,010 | 8,133 | 8,259 | 8,385 |
| EDE | 1,179 | 1,205 | 1,232 | 1,259 | 1,286 | 1,316 | 1,346 | 1,375 |
| GRDA | 1,009 | 1,029 | 1,050 | 1,071 | 1,092 | 1,114 | 1,136 | 1,156 |
| GMOC | 1,991 | 2,031 | 2,070 | 2,107 | 2,150 | 2,383 | 2,455 | 2,504 |
| GSEC | 942 | 959 | 976 | 993 | 1,011 | 1,028 | 1,046 | 1,065 |
| KACY | 559 | 563 | 567 | 571 | 575 | 579 | 583 | 587 |
| KCPL | 3,850 | 3,920 | 4,015 | 4,074 | 4,130 | 4,182 | 4,230 | 4,295 |
| KEPCO | 187 | 189 | 190 | 192 | 193 | 195 | 196 | 198 |
| KPP | 135 | 136 | 138 | 140 | 142 | 143 | 144 | 146 |
| LES | 801 | 814 | 825 | 839 | 853 | 864 | 878 | 887 |
| MIDW | 318 | 320 | 322 | 324 | 325 | 326 | 328 | 330 |
| NPPD | 2,385 | 2,435 | 2,486 | 2,538 | 2,591 | 2,645 | 2,701 | 2,757 |
| OGE | 6,243 | 6,358 | 6,445 | 6,549 | 6,643 | 6,776 | 6,926 | 7,056 |
| OMPA load in OGE BA | 458 | 462 | 466 | 471 | 474 | 479 | 483 | 488 |
| OMPA load in AEPW BA | 145 | 147 | 148 | 149 | 151 | 152 | 153 | 155 |
| OMPA load in WFEC BA | 34 | 34 | 35 | 35 | 35 | 35 | 36 | 36 |
| OPPD | 2,318 | 2,346 | 2,382 | 2,411 | 2,447 | 2,481 | 2,514 | 2,548 |
| SECI | 447 | 452 | 457 | 462 | 468 | 473 | 478 | 483 |
| SPS | 4,058 | 4,129 | 4,202 | 4,276 | 4,351 | 4,428 | 4,506 | 4,585 |
| WFEC | 1,354 | 1,379 | 1,402 | 1,422 | 1,442 | 1,461 | 1,480 | 1,496 |
| WEPLKS | 495 | 500 | 504 | 508 | 512 | 516 | 520 | 524 |
| WRI | 5,042 | 5,102 | 5,169 | 5,265 | 5,317 | 5,371 | 5,425 | 5,485 |

**Table 3-6 SPP Utilities Annual Energy Requirement (GWh)**

| Company | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| AECC | 3,818 | 3,884 | 3,956 | 4,033 | 4,096 | 4,167 | 4,240 | 4,305 |
| CSWS (AEPW) | 37,029 | 37,738 | 38,476 | 39,268 | 39,872 | 40,583 | 41,303 | 41,937 |
| EDE | 5,622 | 5,719 | 5,874 | 6,009 | 6,147 | 6,288 | 6,445 | 6,582 |
| GRDA | 4,568 | 4,653 | 4,746 | 4,841 | 4,938 | 5,037 | 5,138 | 5,231 |
| GMOC | 7,832 | 7,916 | 7,947 | 8,000 | 8,038 | 8,877 | 9,086 | 9,329 |
| GSEC | 5,452 | 5,554 | 5,662 | 5,771 | 5,882 | 5,996 | 6,111 | 6,217 |
| KACY | 2,761 | 2,780 | 2,802 | 2,821 | 2,844 | 2,865 | 2,885 | 2,904 |
| KCPL | 17,153 | 17,427 | 17,987 | 18,327 | 18,653 | 18,969 | 19,277 | 19,572 |
| KEPCO | 970 | 978 | 986 | 995 | 1,003 | 1,013 | 1,024 | 1,033 |
| KPP | 646 | 648 | 659 | 669 | 676 | 684 | 693 | 701 |
| LES | 3,716 | 3,802 | 3,887 | 3,975 | 4,040 | 4,097 | 4,149 | 4,216 |
| MIDW | 1,894 | 1,472 | 1,485 | 1,493 | 1,496 | 1,500 | 1,513 | 1,521 |
| NPPD | 12,955 | 13,311 | 13,685 | 14,069 | 14,464 | 14,870 | 15,288 | 15,717 |
| OGE | 29,811 | 30,374 | 30,835 | 31,380 | 31,881 | 32,582 | 33,378 | 34,002 |
| OMPA load in OGE BA | 1,767 | 1,787 | 1,810 | 1,831 | 1,853 | 1,875 | 1,896 | 1,917 |
| OMPA load in AEPW BA | 561 | 567 | 574 | 581 | 588 | 595 | 602 | 608 |
| OMPA load in WFEC BA | 131 | 132 | 134 | 136 | 137 | 139 | 141 | 142 |
| OPPD | 10,692 | 10,829 | 11,005 | 11,153 | 11,328 | 11,498 | 11,663 | 11,821 |
| SECI | 2,414 | 2,442 | 2,469 | 2,497 | 2,525 | 2,554 | 2,583 | 2,609 |
| SPS | 23,522 | 23,962 | 24,425 | 24,896 | 25,377 | 25,867 | 26,366 | 26,825 |
| WFEC | 6,976 | 7,077 | 7,182 | 7,276 | 7,365 | 7,455 | 7,543 | 7,625 |
| WEPLKS | 2,568 | 2,591 | 2,613 | 2,637 | 2,658 | 2,684 | 2,713 | 2,737 |
| WRI | 23,875 | 23,915 | 24,400 | 24,818 | 25,113 | 25,435 | 25,760 | 26,119 |

**Table 3-7 SPP Utilities 2010 Monthly Energy Forecast (GWh)**

| Company | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECC | 312 | 269 | 280 | 271 | 321 | 359 | 413 | 428 | 346 | 293 | 278 | 314 |
| CSWS (AEPW) | 3,029 | 2,617 | 2,724 | 2,635 | 3,115 | 3,486 | 4,014 | 4,155 | 3,363 | 2,850 | 2,703 | 3,048 |
| EMDE | 523 | 448 | 448 | 388 | 422 | 485 | 573 | 588 | 472 | 417 | 434 | 519 |
| GRDA | 397 | 343 | 341 | 314 | 357 | 412 | 495 | 501 | 403 | 344 | 344 | 402 |
| GMOC | 685 | 591 | 601 | 533 | 590 | 707 | 853 | 848 | 665 | 571 | 586 | 686 |
| GSEC | 430 | 387 | 427 | 434 | 478 | 513 | 597 | 566 | 465 | 432 | 424 | 400 |
| KACY | 230 | 203 | 215 | 199 | 218 | 247 | 286 | 290 | 240 | 214 | 211 | 228 |
| KCPL | 1,447 | 1,253 | 1,302 | 1,200 | 1,345 | 1,586 | 1,907 | 1,886 | 1,497 | 1,282 | 1,278 | 1,445 |
| KEPCO | 77 | 69 | 73 | 70 | 78 | 88 | 107 | 103 | 86 | 76 | 73 | 79 |
| KPP | 51 | 46 | 48 | 45 | 51 | 59 | 71 | 71 | 57 | 49 | 47 | 53 |
| LES | 320 | 285 | 298 | 271 | 294 | 337 | 398 | 389 | 316 | 293 | 283 | 317 |
| MIDW | 113 | 101 | 107 | 101 | 114 | 135 | 167 | 164 | 131 | 116 | 108 | 116 |
| NPPD | 1,214 | 1,097 | 939 | 884 | 911 | 1,078 | 1,596 | 1,419 | 989 | 981 | 1,018 | 1,184 |
| OGE | 2,442 | 2,151 | 2,232 | 2,103 | 2,455 | 2,763 | 3,250 | 3,334 | 2,711 | 2,275 | 2,198 | 2,461 |
| OMPA load in OGE BA | 128 | 114 | 118 | 115 | 145 | 176 | 219 | 223 | 171 | 128 | 118 | 132 |
| OMPA load in AEPW BA | 40 | 36 | 37 | 36 | 46 | 55 | 69 | 71 | 54 | 40 | 37 | 42 |
| OMPA load in WFEC | 10 | 8 | 9 | 9 | 11 | 13 | 16 | 17 | 13 | 9 | 9 | 10 |
| OPPD | 908 | 837 | 772 | 742 | 870 | 987 | 1,165 | 1,170 | 880 | 823 | 781 | 895 |
| SUNC | 191 | 173 | 191 | 181 | 198 | 216 | 255 | 246 | 208 | 196 | 190 | 196 |
| SWPS | 1,857 | 1,669 | 1,844 | 1,871 | 2,062 | 2,215 | 2,575 | 2,442 | 2,006 | 1,866 | 1,830 | 1,726 |
| WEFA | 620 | 533 | 533 | 472 | 540 | 613 | 740 | 741 | 602 | 516 | 525 | 641 |
| WEPLKS | 204 | 183 | 193 | 185 | 206 | 232 | 283 | 273 | 227 | 202 | 194 | 209 |
| WRI | 1,900 | 1,693 | 1,761 | 1,679 | 1,878 | 2,173 | 2,607 | 2,626 | 2,093 | 1,812 | 1,747 | 1,946 |

## 3.4 Transmission Grid Modeling

The transmission models used were the summer peak models for each year of the study including facility changes consistent with those of the 2008 Q2 SPP Transmission Expansion Plan, and the 2008 Nebraska and GMOC Transmission Expansion Plans. These models were provided by the SPP Engineering department for use by Ventyx. For simplification, any facility changes in place for the summer peak model were also assumed in place at the beginning of the year.

## 3.5 Other Assumptions

The model also required several other data inputs. These are summarized below.

### 3.5.1 Spinning and Regulating Reserve Requirements

The SPP Reserve Sharing Group total operating reserve requirement (Spin + NonSpin) is calculated as the largest contingency within the group plus 50% of the second largest contingency. The spinning reserve requirement must be at least half of the total operating reserve, and each member system of the reserve sharing group is required to maintain their "load-weighted" share of the reserve requirements. For the Study Topology, we used the spinning reserve requirement by Balancing Authority shown in Table 3-8 below.

Additionally, the Balancing Authority spinning reserve requirements were augmented by 1% of the monthly forecasted peak demand, to model up-regulation. For Change Case II, i.e. the Day-Ahead Market with ASM, the BA reserve requirements were aggregated into the single SPP-wide reserve requirement.

**Table 3-8 Allocation of Reserve Requirements to Balancing Authorities**

| Balancing Authority | Spinning Reserve Requirement (MW) |
|---|---|
| | |
| AEPW_BA | 118 |
| EDE | 15 |
| GMOC | 21 |
| GRDA | 17 |
| KACY | 7 |
| KCPL | 54 |
| LES | 9* |
| NPPD | 42 |
| OGE_BA | 88 |
| OPPD | 29 |
| SECI_BA | 10 |
| SPS_BA | 75 |
| WFEC | 20 |
| WRI_BA | 90 |

**LES requirement covered by long-term contract with WAPA.*

### 3.5.2 Escalation Assumptions

O&M costs and emergency energy cost were escalated at three percent per year.

### 3.5.3 Demand Response Assumptions

Modeling of demand response is incorporated for the future market study period (2009-2016). A strike price of $150 was applied to the demand response participants. A more detailed description of the Demand Response program model development has been included in Appendix B.

### 3.5.4 Discount Rates

The implementation costs, operational benefits and net benefits have been presented in 2008 dollars based on two discount rates, one representing entities which would incur a tax impact, and a second discount rate to represent entities with no tax obligation. Table 3-9 below describes a derived rate of return for the general electric utility industry based on the assumptions outlined. The cost of debt is based on the $1.95 billion in electric utility debt issued in the month of October 2008. Most of the investments required to be made to achieve the revenue in the report will likely be financed by debt, an 80%/20% blend was used here. This ratio is based on data in an October 2008 Moody's report on investor-owned electric utilities.

**Table 3-9 Rate of Return**

| **Assumptions** | | | **Assumptions** | | |
|---|---|---|---|---|---|
| % of marginal dollars financed by debt | | 80% | % of marginal dollars financed by debt | | 80% |
| Cost of equity is based on the electric utility industry's average Return on Equity for 2007. | | | Cost of equity is based on the electric utility industry's average Return on Equity for 2007. | | |
| Cost of debt is based on BBB rated debt offerings from the electric utility from 10/1/2008 through 1/8/2009. | | | Cost of debt is based on BBB rated debt offerings from the electric utility from 10/1/2008 through 1/8/2009. | | |
| Average maturity of debt is 8 years. | | | Average maturity of debt is 8 years. | | |
| Estimated cost of equity | 11.50% | | Estimated cost of equity | 11.50% | |
| x financing factor | 20% | | x financing factor | 20% | |
| Weighted average cost of equity | | 2.30% | Weighted average cost of equity | | 2.30% |
| Estimated cost of debt | 7.50% | | Estimated cost of debt | 7.50% | |
| Corporate tax rate | 0% | | Effective corporate tax rate | 40% | |
| x financing factor | 80% | | x financing factor | 80% | |
| Weighted average cost of debt | | 6.00% | Weighted average cost of debt | | 3.60% |
| Total current rate of return | | 8.30% | Total current rate of return | | 5.90% |
| **Rounded** | | **8.30%** | **Rounded** | | **5.90%** |

# 4 Findings

This chapter summarizes the primary results of the study. The chapter focuses on the estimates of benefits and costs developed using the methodology discussed in Chapter 2. Section 4.1 presents the benefits and costs at the aggregate level, i.e., for the entirety of SPP. Section 4.2 provides benefit and cost estimates at various levels of disaggregation, such as by state. Change Case IV, a Simplified Day-Ahead Market, is discussed in section 4.3. Other results not directly associated with benefits and costs, such as locational marginal prices and the allocation of ancillary services across balancing authorities, are summarized in Section 4.4., and the potential effects of higher-than-expected wind penetration on the benefit estimates are discussed in Section 4.5.

## 4.1 Aggregate Benefits and Costs

At the SPP level, the estimated net benefits for each change case in each year are equal to 1) the estimated gross benefits for the change case / year, which are equal in turn to the difference in estimated adjusted production costs between the base case and the change case in question; minus 2) estimated implementation and on-going costs of the change case, which include costs borne by both SPP and market participants. Gross benefit estimates are discussed in sub-section 4.1.1, cost estimates in sub-section 4.1.2, and net benefit estimates in sub-section 4.1.3.

### 4.1.1 Gross Benefits

Figure 4-1 displays the estimated annual adjusted production costs for each year and case (base as well as Change Cases I, IIA, and III)[4]. As discussed in Chapter 2, estimated production costs for a year / case are equal to estimated total fuel and variable O&M costs (including start costs) incurred by SPP market participants. Estimated adjusted production costs are estimated production costs plus the estimated purchase costs of imports from entities outside SPP less the estimated revenues earned from exports to entities outside SPP. The figure displays two important phenomena:

- As one would expect, the differences in estimated adjusted production costs between any two cases (e.g., between the Base Case and Change Case I, which represents the Change Case I gross benefits) are relatively small compared to the level of estimated base case costs.

- Estimated adjusted production costs increase dramatically in all cases between 2012 and 2013 due to the assumed imposition of a carbon emission cap-and-trade system (or carbon tax) in 2013, with an assumed allowance price (or tax) of $10 / ton in 2013. Additional increases after 2013 are, in turn, due primarily to the combination

[4] Estimated adjusted production costs for Change Cases IIB and IIC are not displayed, because IIB is the same as I in 2009-2010 and IIA in 2011-2016, and IIC is the same as III in 2009-2010 and IIA in 2011-2016.

of load growth and the assumption that no additional generating resources are added during the study period, which causes the capacity factors of inefficient generators to increase over time. The assumed annual increase in the carbon allowance price of $1/ton after 2013 also contributes to the estimated post-2013 production cost increases.

**Figure 4-1 Annual Adjusted Production Costs (Million $)**

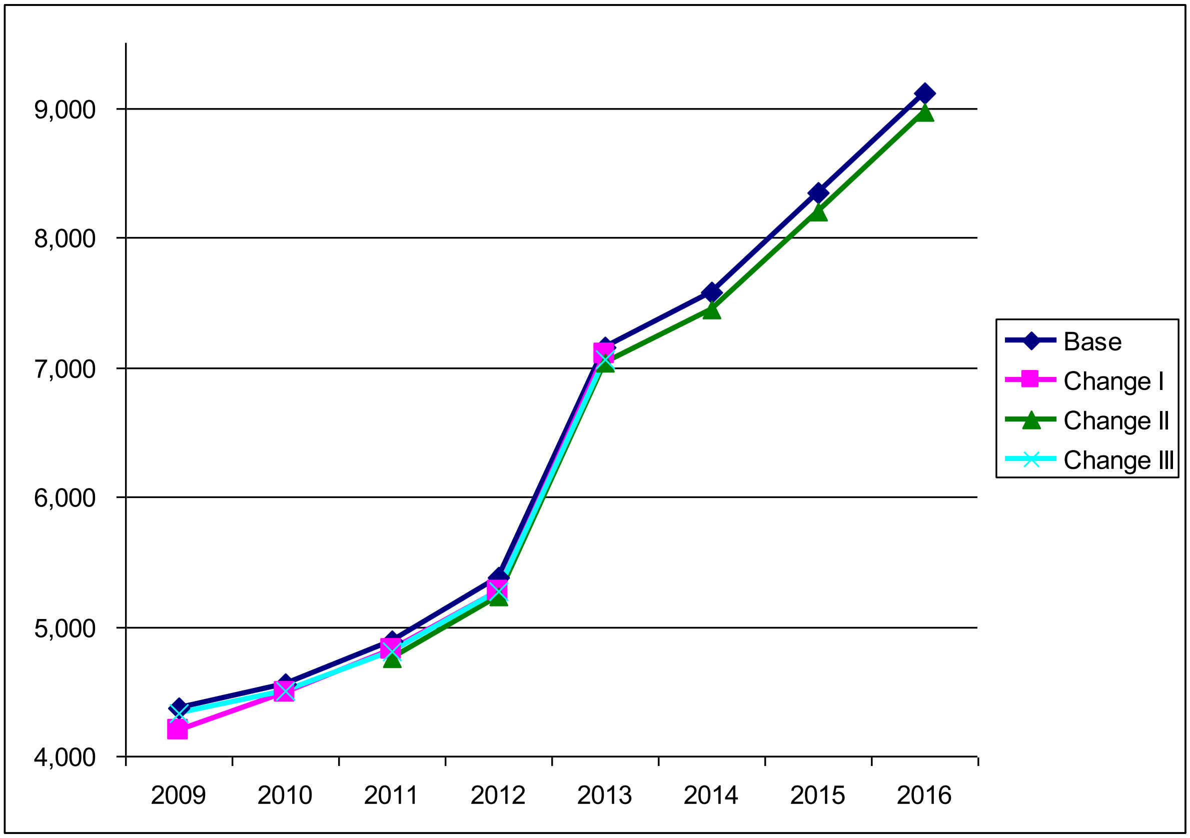



Table 4-1 summarizes the estimated annual SPP-level gross benefits for each of Change Cases I, IIA, IIB, IIC, and III[5]. During the 2011 – 2016 period (the period for which gross benefits for all three change cases were calculated), estimated gross benefits in Change Case I average approximately $85 million per year, while the Change Case IIA estimated gross

[5] This study was begun in early 2008, at a point in time when it seemed feasible to start either the Day-Ahead Market (Change Case I) or the Ancillary Service Market (Change Case III) in January 2009; but not feasible to start the combined Day-Ahead and Ancillary Services Market (Change Case IIA) until January 2011. All of the analysis was performed consistent with these assumptions, and the analytic results summarized in this report are presented in a manner consistent with these assumptions. However, due to the time required to complete the study, it is no longer feasible to start either the Day-Ahead Market or the Ancillary Service Market in January 2009. Moreover, subsequent investigation (outside of this study) indicates that it might not be feasible to start either the Day-Ahead Market or the Ancillary Services Market earlier than the combined Day-Ahead and Ancillary Services Market.

benefits average approximately $150 million per year and the estimated annual Change Case III gross benefits average approximately $105 million per year.

It is important to note that the estimated gross benefits associated with implementing both the day-ahead market and the ancillary services market (Change Case IIA) are less than the sum of the estimated benefits for implementing just one of the two markets (Change Cases I and III). The reason for this is as follows:

- It is expected that the estimated gross benefits of Change Case IIA would be less than or equal to the sum of the estimated gross benefits of Change Cases I and III, because the estimated gross benefits for each of those Change Cases reflects a separate "optimization" of gross benefits with respect to Day-Ahead Commitment (I) and Ancillary Services (III).

- The market changes addressed in Change Case IIA create estimated benefits that are less than the sum of the benefits of Change Cases I and III because the objectives that are considered in the separate optimization problems in Change Cases I and III, but jointly in Change Case IIA are occasionally in conflict, i.e., one commitment and dispatch leads to the least-cost solution for Change Case I, and a different commitment and dispatch leads to the least-cost solution for Change Case III.

Several time patterns of estimated annual gross benefits are also important to note, in particular:

- The estimated Change Case I gross benefits are substantially larger than those for Change Case III in 2009, despite being similar in most of the other years, apparently due to a combination of low wind generation (relative to load), very low gas prices, and transmission upgrades that take place beginning in 2010.

- The estimated Change Case I gross benefits increase significantly between 2011 and 2012 while those for the other Change Cases decrease, apparently due to the effect of the additional 600-MW coal-fired unit in CSWS (AEPW). The effects of this addition on estimated Change Case I gross benefits are reduced in later years due to the assumed imposition of the carbon cap-and-trade program. The addition affects estimated Change Case I gross benefits more than those of the other Change Cases because it has little impact on the provision of ancillary services.

- The estimated Change Case II gross benefits are lower in each of the years 2013 – 2016 than in 2011 and 2012, despite rising fuel prices and inflation, because the imposition of carbon emission cap-and-trade system (or carbon taxes) in 2013 reduces the savings associated with the switch toward coal-fired generation that is attributable to a more efficient commitment and dispatch. This is also true for Change Cases I and III in 2013, the last year for which gross benefits were estimated via simulation for these two Change Cases (i.e., gross benefits for the years 2014-2016 for these two Change Cases were estimated using extrapolation).

The bottom three rows of Table 4-1 report the total undiscounted estimated gross benefits in each change case, as well as the net present value[6] of estimated gross benefits at discount rates of 5.9% and 8.3%. As would be expected from the preceding discussion, the undiscounted and discounted total gross benefit estimates are higher for Change Cases IIA, IIB, and IIC then for Change Cases I or III; those for IIB (IIC) and are higher than IIA because IIB (IIC) includes the Day-Ahead Market (Ancillary Services Market) in 2009 and 2010, while IIA assumes the new market does not begin until 2011.

**Table 4-1 Gross Benefits (Million $)**

| | I | IIA | IIB | IIC | III |
|---|---|---|---|---|---|
| **2009** | 101 | | 101 | 34 | 34 |
| **2010** | 60 | | 60 | 52 | 52 |
| **2011** | 94 | 171 | 171 | 171 | 92 |
| **2012** | 124 | 160 | 160 | 160 | 109 |
| **2013** | 75 | 132 | 132 | 132 | 93 |
| **2014** | 75 | 136 | 136 | 136 | 98 |
| **2015** | 70 | 137 | 137 | 137 | 109 |
| **2016** | 79 | 153 | 153 | 153 | 119 |
| **Total** | **679** | **889** | **1,050** | **975** | **706** |
| **NPV @ 5.9%** | **518** | **637** | **781** | **713** | **515** |
| **NPV @ 8.3%** | **469** | **560** | **699** | **633** | **457** |

The gross benefit estimates displayed in Table 4-1 are the result of a more efficient commitment and dispatch in each of the change cases than in the base case. These efficiency improvements are summarized in Figure 4-2, Figure 4-3, Figure 4-4, and Figure 4-5, which display the estimated annual changes (relative to the base case) in estimated generation for four major generator types[7]. In all Change Cases, coal-fired generation increases due to more efficient market operation. For Change Cases I and IIA, energy produced from expensive gas-fired steam and combustion turbines is lower than in the base case; replaced by energy produced from less expensive coal-fired steam turbine units. However, in Change Case III, the decision of which generators will supply AS reserves is influenced by the commitment decisions made at the balancing authority level. Given those commitment choices, it is more efficient on some days to operate combustion turbines for a few hours than to start a combined cycle to operate all day. Thus, CT generation increases somewhat in Change Case III. Figure 4-6 displays the net remaining supply from generators (including nuclear and hydro) and imports from entities outside SPP, less exports to entities outside SPP, to supply the SPP market demand.

[6] All net present values in this report have a base date of January 1, 2008.
[7] Note that 1) the vertical scales are not the same across the five figures; and 2) results for Change Cases I and III are not shown for 2014 – 2016 in these figures, because Ventyx did not simulate these years for these Change Cases, but estimated the gross benefits through extrapolation, as discussed in Chapter 2.

**Figure 4-2 Combined Cycle Annual Generation, By Case (GWh)**

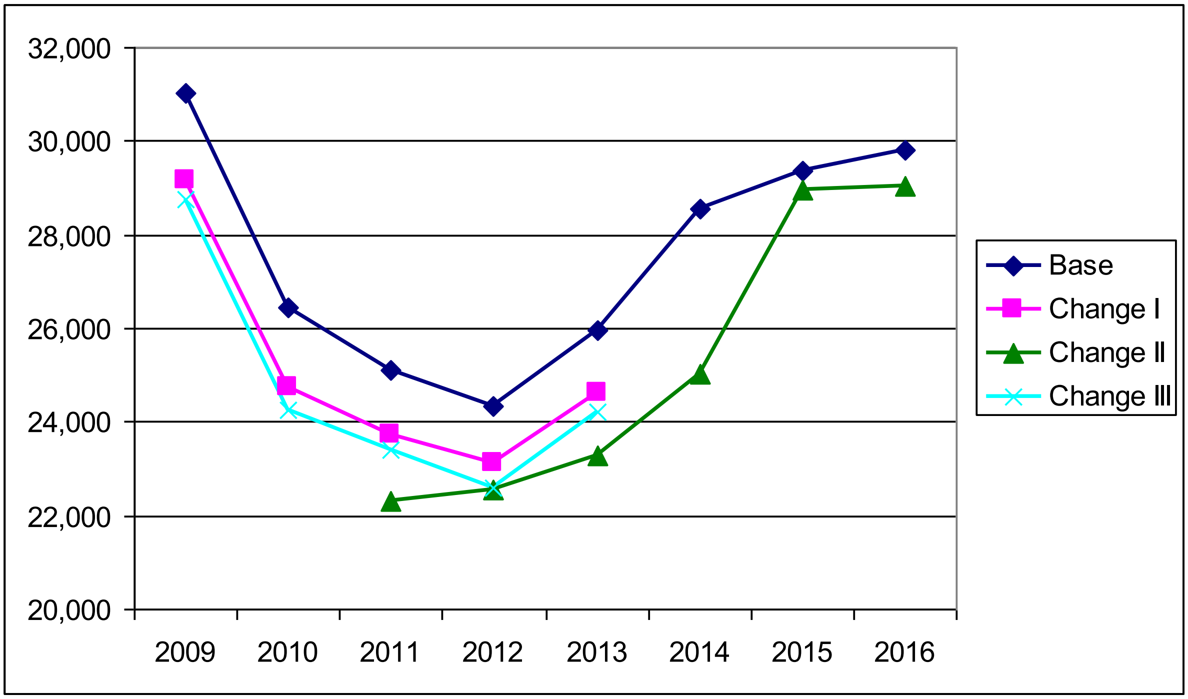



**Figure 4-3 Combustion Turbine Annual Generation, By Case (GWh)**

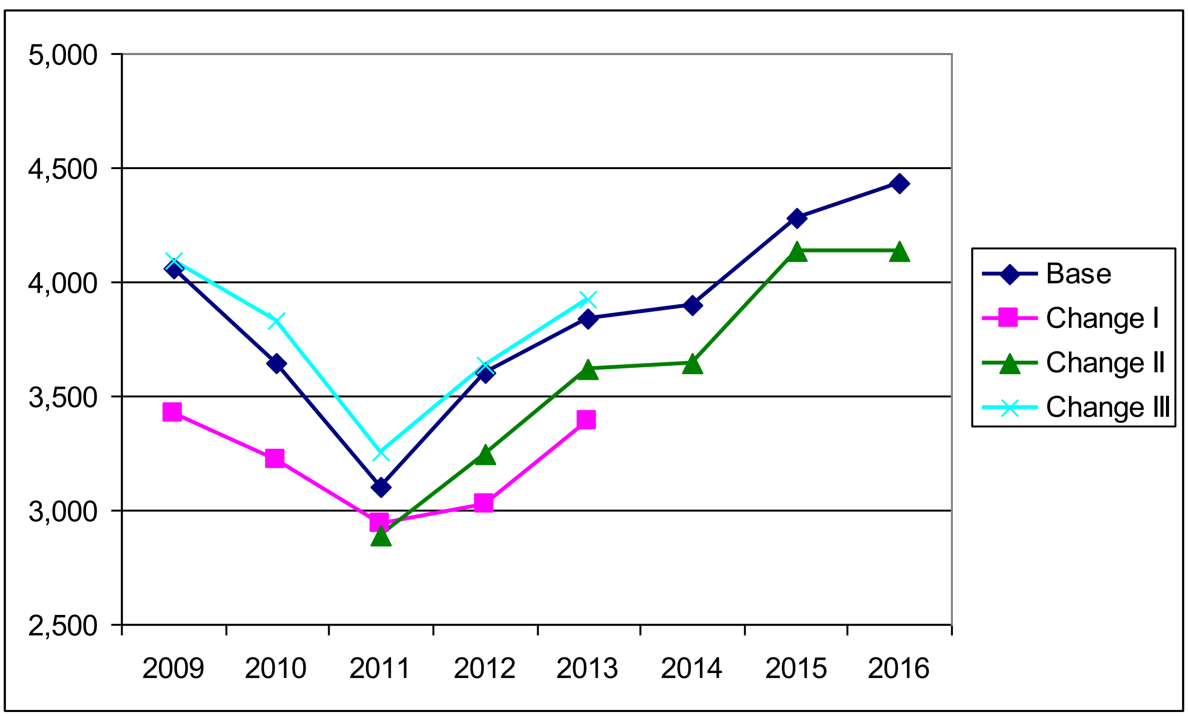


**Figure 4-4 Steam Coal Annual Generation, By Case (GWh)**

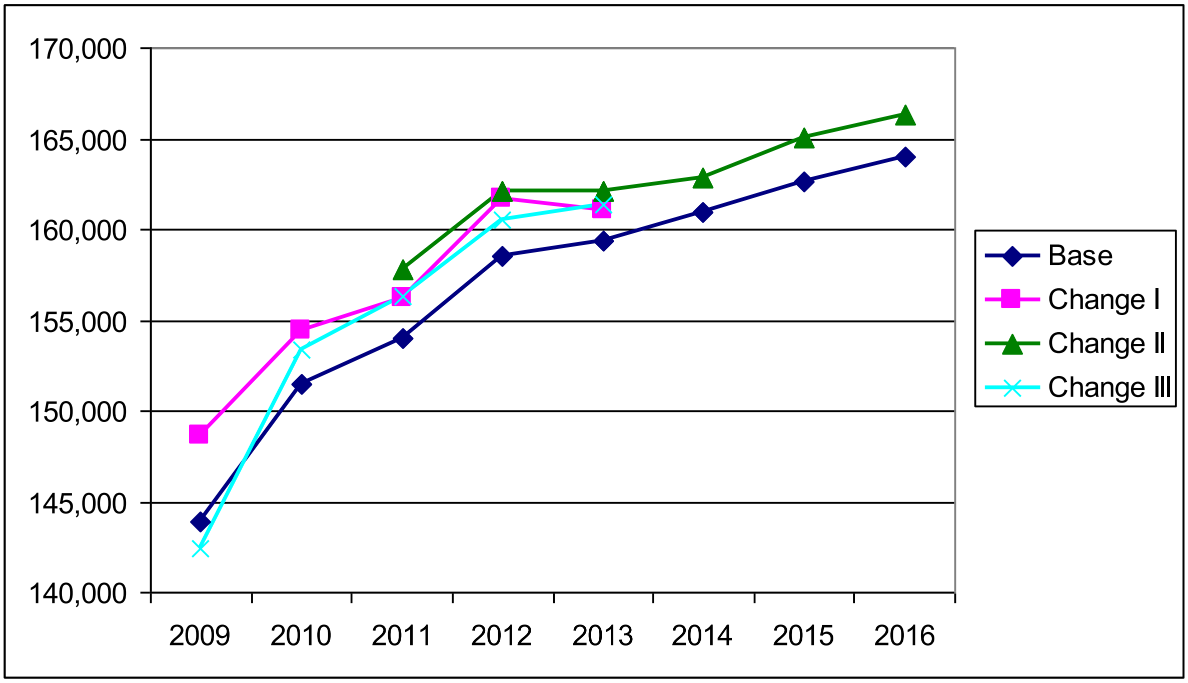



**Figure 4-5 Steam Gas Generation, By Case (GWh)**

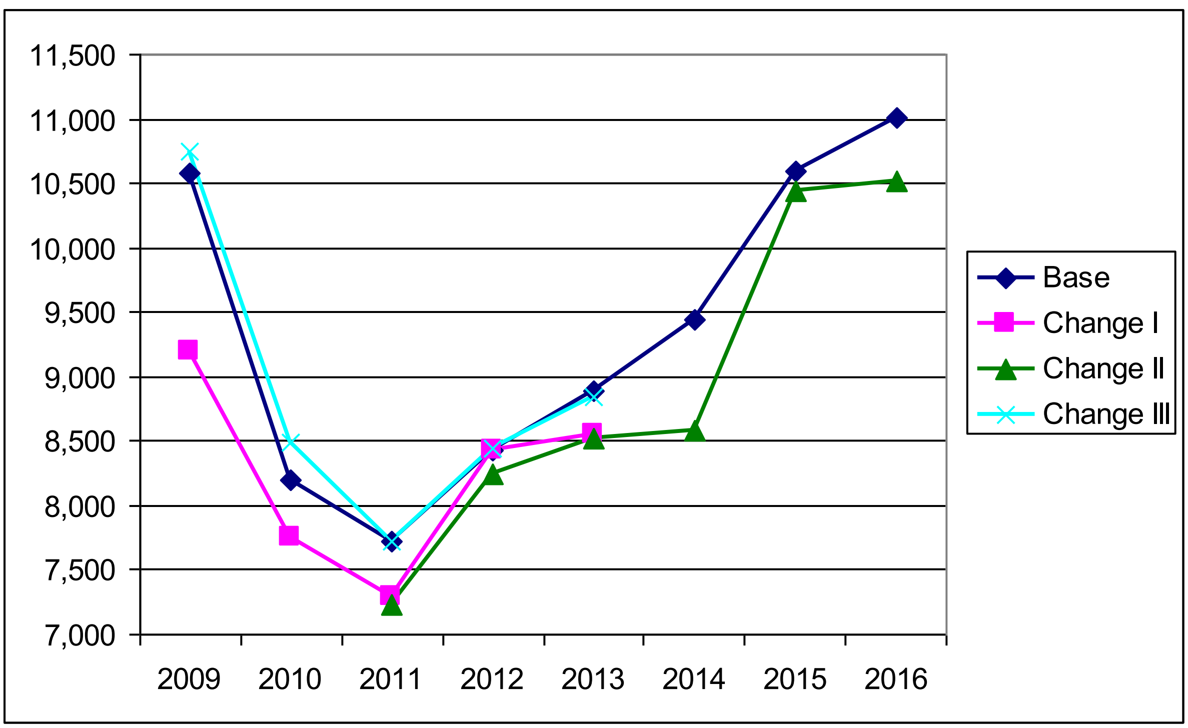
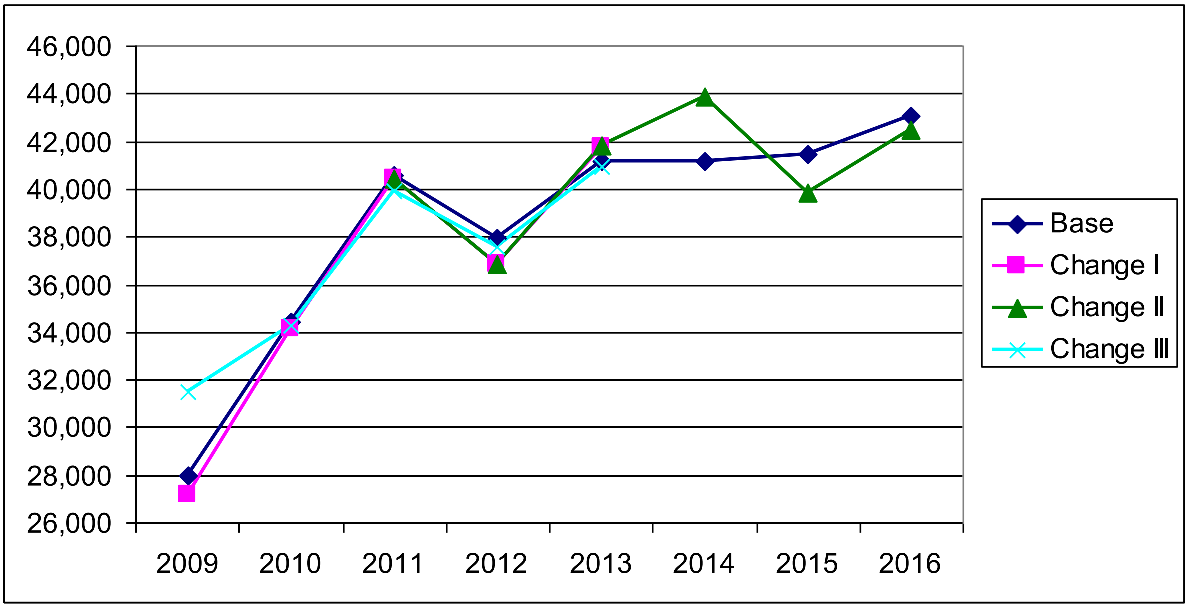


**Figure 4-6 SPP Net Remaining Supply by Case (GWh)**




### 4.1.2 Implementation Costs

Figure 4-7 summarizes the estimated capital expenditures that SPP would incur in each change case and year. Detailed descriptions of these expenditures are provided in Appendix C. Total (undiscounted) estimated capital expenditures are approximately $24 million in Change Case I, $44 million in all of the variations of Change Case II, and $12 million in Change Case III.

Figure 4-8 summarizes the estimated annual operating costs that SPP would incur in each Change Case and year. These cost estimates include depreciation of the capital expenditures described in Figure 4-7. Again, detailed descriptions of these are provided in the Appendix C. Total (undiscounted) estimated operating costs over the 2008 – 2016 period are approximately $120 million in Change Case I, vary between $110 million and $130 million in the variations of Change Case II, and are approximately $60 million in Change Case III.

**Figure 4-7 SPP Implementation Capital Expenditures (Million $)**

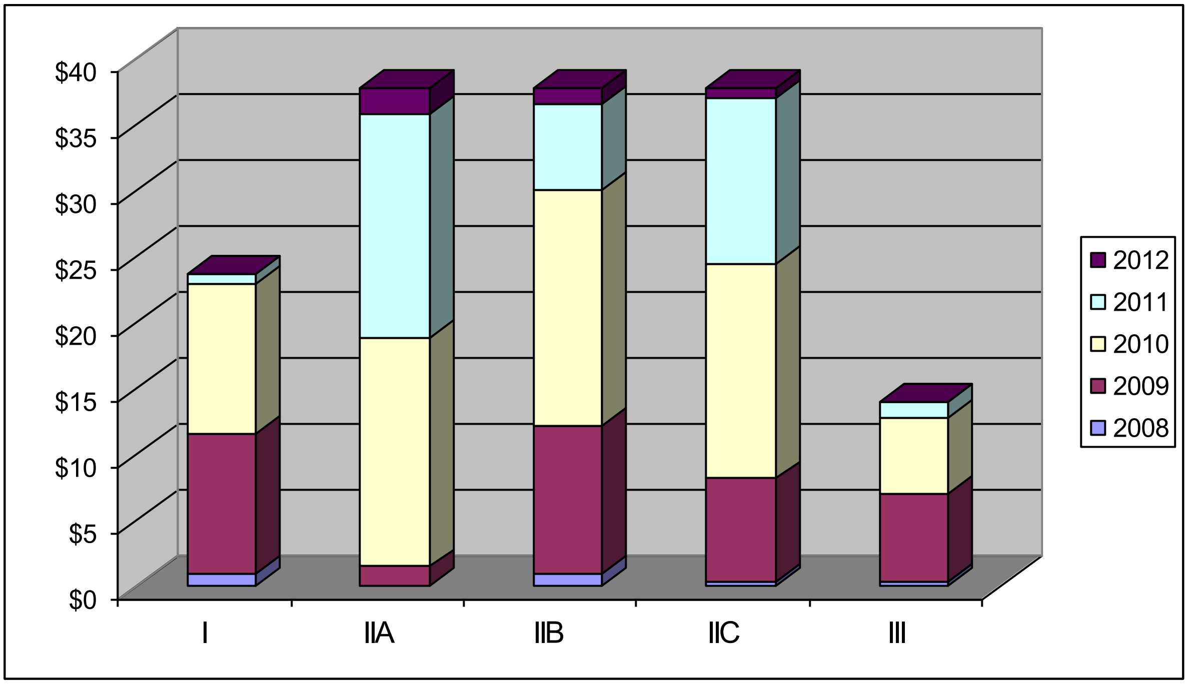
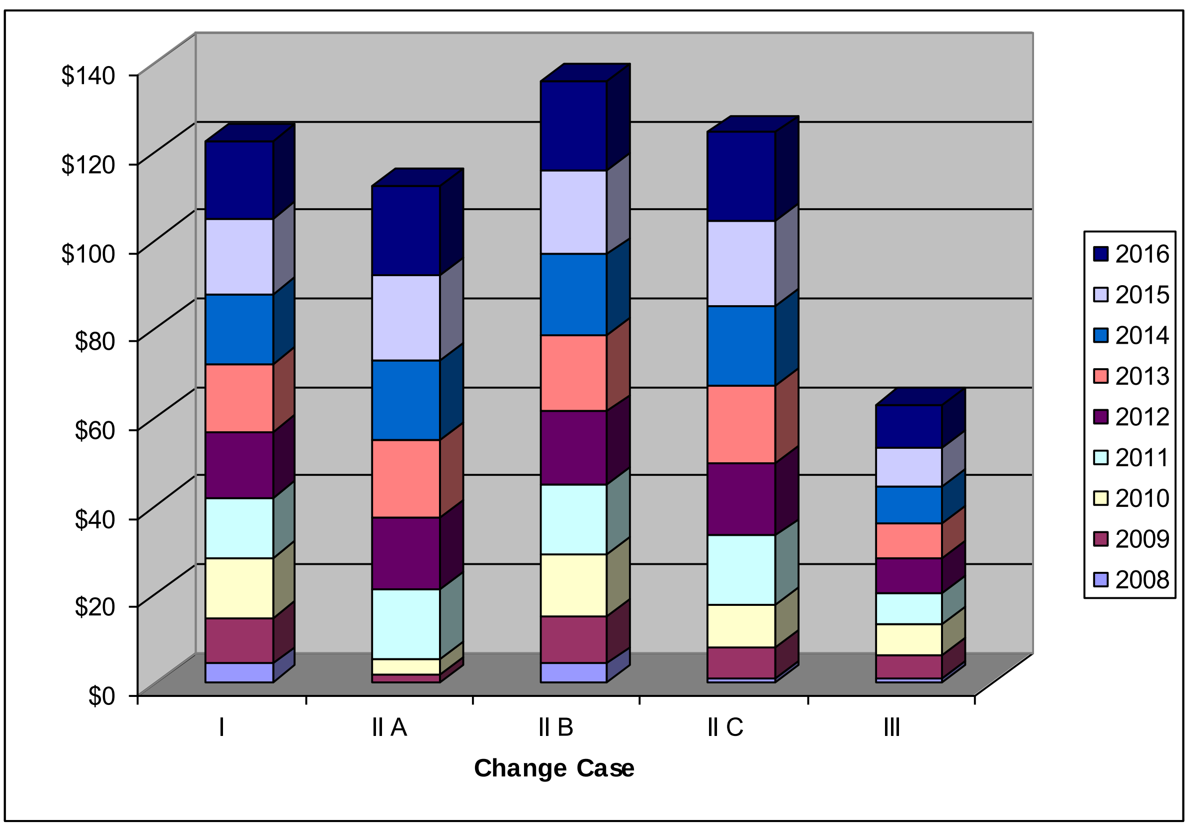



**Figure 4-8 SPP Implementation Annual Operating Costs (Million $)**



For the purpose of cost benefit analysis, the costs incurred by market participants must also be taken into account, not just the costs incurred by SPP directly. For this purpose, each market participant was assigned to one of four categories: Large / Complex, Large / Simple, Small / Complex, and Small / Simple. See Appendix D for Market Participant's categories. Estimates of capital expenditures and annual operating costs were developed for each of the four categories for each of the Change Cases. Table 4-2 summarizes these estimates. Detailed descriptions of these expenditures and costs are provided in the Appendix D.

Table 4-3 summarizes the total estimated annual implementation costs for each of the Change Cases. The estimates presented in the table include costs incurred by SPP and the market participants. For SPP, the annual costs include operating costs plus the depreciation of capital expenditures (i.e., consistent with Figure 4-7). For the market participants, the annual cost estimates include estimated capital expenditures, which were assumed to be incurred the year prior to the market change (e.g., in 2008 for Changes Cases I and III, which are assumed throughout this study to begin in 2009); plus estimated annual operating costs.

**Table 4-2 Market Participant Implementation Costs (Thousand $/Participant)**

| | Change Case | | | |
|---|---|---|---|---|
| | I | II | III | IV |
| **Capital Costs (One time)** | | | | |
| **Complex** | | | | |
| Large | 2800 | 2950 | 2300 | 2800 |
| Small | 1600 | 1700 | 1050 | 1600 |
| **Simple** | | | | |
| Large | 1700 | 1775 | 1550 | 1700 |
| Small | 300 | 350 | 200 | 300 |
| **Annual Operating Costs** | | | | |
| **Complex** | | | | |
| Large | 1100 | 1250 | 700 | 1100 |
| Small | 600 | 700 | 350 | 600 |
| **Simple** | | | | |
| Large | 600 | 675 | 450 | 600 |
| Small | 250 | 300 | 150 | 250 |

Table 4-3 Annual SPP and Market Participant Implementation Costs (Million $)

| | Case I | Case II A | Case II B | Case II C | Case III |
|---|---|---|---|---|---|
| **2008** | 36 | 0 | 37 | 34 | 26 |
| **2009** | 24 | 2 | 24 | 11 | 9 |
| **2010** | 27 | 36 | 28 | 14 | 11 |
| **2011** | 28 | 32 | 32 | 32 | 12 |
| **2012** | 30 | 34 | 34 | 34 | 12 |
| **2013** | 31 | 36 | 36 | 36 | 13 |
| **2014** | 33 | 37 | 37 | 37 | 14 |
| **2015** | 34 | 39 | 39 | 39 | 14 |
| **2016** | 36 | 41 | 41 | 41 | 15 |
| **Total** | **278** | **258** | **308** | **278** | **128** |
| **NPV @ 5.9%** | **215** | **188** | **237** | **210** | **101** |
| **NPV @ 8.3%** | **196** | **167** | **215** | **190** | **93** |

### 4.1.3 Net Benefits

Tables 4-4 through 4-6 display the estimated annual gross benefits, costs, and net benefits for each of the three market options. The bottom three rows of each table display the total (undiscounted) sum of the three variables, as well as net present values at discount rates of 5.9% and 8.3%.

The tables can be summarized as follows:

- Total undiscounted and discounted estimated gross benefits greatly exceed costs for all Change Cases, including all three variations of Change Case II, i.e., total estimated net benefits are positive.

- Between the Change Cases, IIB has higher estimated net benefits, followed by IIC and IIA. The reason for this is that IIA does not start yielding net benefits until 2011, while IIB and IIA begin generating positive net benefits in 2009. In other words, selecting IIA instead of IIB or IIC "leaves money on the table" during 2009 and 2010[8].

- The estimates of gross benefits are sensitive to a number of assumptions that were made during the study (and are discussed in Chapter 3). In particular, estimated annual gross benefits for each Change Case would likely be reduced by an assumption of lower natural gas prices, higher coal prices, or higher carbon allowance prices, because the benefit of displacing natural gas-fired generation (especially from

[8] Note that this is only relevant if it is feasible to implement Change Case I/IIB or Change Case III/IIC earlier than Change Case IIA can be implemented. The analysis summarized in this report is based on this assumption, based on what SPP and Ventyx believed at the time the study began. As indicated in footnote 4 above, investigation performed outside of this study since the study was begun suggests that it may not be feasible to start Change Cases I/IIB or III/IIC earlier than Change Case II.

steam units) with coal-fired generation would decrease. However, in all Change Cases, gross benefits are more than 225% of the costs. As a result, if actual costs turned out to be 40% higher than estimated here, and actual gross benefits turned out to be 40% lower than estimated here, actual net benefits would still be positive for these all Change Cases. Alternatively, if actual costs equaled estimated costs, gross benefits could be 60% less than estimated here and net benefits would still be positive for all Change Cases.

- Once each market structure begins operation (i.e., 2009 for Change Cases I, IIB, IIC, and III, 2011 for Change Case IIA), the estimated annual gross benefits are at least twice as large as the estimated annual costs, so that estimated annual net benefits are consistently positive. Thus, there is nothing to be gained by trying to "time" the start of a new market to occur in a year during which "attractive" conditions (i.e., those producing higher gross benefits) might occur (e.g., to potentially coincide with higher natural gas prices).

**Table 4-4 Change Case I Gross Benefits, Costs, and Net Benefits (Million $)**

| | Costs | Gross Benefits | Net Benefits |
|---|---|---|---|
| **2008** | 36 | 0 | (36) |
| **2009** | 24 | 101 | 78 |
| **2010** | 27 | 60 | 33 |
| **2011** | 28 | 94 | 66 |
| **2012** | 30 | 124 | 95 |
| **2013** | 31 | 75 | 44 |
| **2014** | 33 | 75 | 43 |
| **2015** | 34 | 70 | 36 |
| **2016** | 36 | 79 | 43 |
| **Total** | **278** | **679** | **400** |
| **NPV @ 5.9%** | **215** | **518** | **303** |
| **NPV @ 8.3%** | **196** | **469** | **273** |

Table 4-5 Change Case II Gross Benefits, Costs, and Net Benefits (Million $)

| | Case II A | | | Case II B | | | Case II C | | |
|---|---|---|---|---|---|---|---|---|---|
| | Costs | Gross Benefits | Net Benefits | Costs | Gross Benefits | Net Benefits | Costs | Gross Benefits | Net Benefits |
| **2008** | 0 | 0 | 0 | 37 | 0 | (37) | 34 | 0 | (34) |
| **2009** | 2 | 0 | (2) | 24 | 101 | 77 | 11 | 34 | 23 |
| **2010** | 36 | 0 | (36) | 28 | 60 | 32 | 14 | 52 | 38 |
| **2011** | 32 | 171 | 139 | 32 | 171 | 139 | 32 | 171 | 139 |
| **2012** | 34 | 160 | 126 | 34 | 160 | 126 | 34 | 160 | 126 |
| **2013** | 36 | 132 | 97 | 36 | 132 | 97 | 36 | 132 | 97 |
| **2014** | 37 | 136 | 99 | 37 | 136 | 99 | 37 | 136 | 99 |
| **2015** | 39 | 137 | 98 | 39 | 137 | 98 | 39 | 137 | 98 |
| **2016** | 41 | 153 | 112 | 41 | 153 | 112 | 41 | 153 | 112 |
| **Total** | **258** | **889** | **632** | **308** | **1,050** | **742** | **278** | **975** | **697** |
| **NPV @ 5.9%** | **188** | **637** | **448** | **237** | **781** | **544** | **210** | **713** | **503** |
| **NPV @ 8.3%** | **167** | **560** | **393** | **215** | **699** | **484** | **190** | **633** | **443** |

Table 4-6 Change Case III Gross Benefits, Costs, and Net Benefits (Million $)

| | Costs | Gross Benefits | Net Benefits |
|---|---|---|---|
| **2008** | 26 | 0 | (26) |
| **2009** | 9 | 34 | 24 |
| **2010** | 11 | 52 | 41 |
| **2011** | 12 | 92 | 80 |
| **2012** | 12 | 109 | 97 |
| **2013** | 13 | 93 | 80 |
| **2014** | 14 | 98 | 85 |
| **2015** | 14 | 109 | 94 |
| **2016** | 15 | 119 | 103 |
| **Total** | **128** | **706** | **578** |
| **NPV @ 5.9%** | **101** | **515** | **414** |
| **NPV @ 8.3%** | **93** | **457** | **364** |

Table 4-7 summarizes the estimated net benefits for the five different Change Cases. As indicated in the preceding discussion, all of the Change Cases have positive net present values. In descending order, the Change Cases are IIB, IIC, IIA, III, and I.

**Table 4-7 Summary of Net Benefits (Million $)**

| | Total | NPV @ 5.9% | NPV @ 8.3% |
|---|---|---|---|
| **Case I** | 400 | 303 | 273 |
| **Case II A** | 632 | 448 | 393 |
| **Case II B** | 742 | 544 | 484 |
| **Case II C** | 697 | 503 | 443 |
| **Case III** | 578 | 414 | 364 |

## 4.2 Disaggregated Benefits

Estimates of state-level gross benefits are discussed in sub-section 4.2.1, balancing authority-level gross benefits in sub-section 4.2.2, and market participant-level gross benefits in sub-section 4.2.3.

The tables presented in sections 4.2.1 – 4.2.3 each include a row labeled "Unallocated Congestion." As discussed in Chapter 2, in every hour and Change Case (including the Base Case) estimated adjusted production costs for a sub-SPP entity (e.g., state) equals production costs (i.e., fuel and O&M costs) plus the cost of purchases from other states at the state's load-weighted average LMP minus the revenues from sales to other states at the state's generation-weighted average LMP. In each hour, if the selling state's generation-weighted average LMP is lower than the purchasing state's load-weighted average LMP, the difference reflects congestion, because if the transmission capacity between the two states was infinite, the LMPs in the two states would be the same. As a result of this congestion, the sum of the states' unadjusted production costs (which in the absence of imports from and exports to entities outside SPP represents SPP adjusted production costs) is less than the sum of the states' adjusted production costs.

Between the Base Case and each Change Case, the total value of congestion can increase or decrease, depending on whether LMPs or quantities transacted between sub-SPP entities change proportionately more. It was outside the scope of this study to allocate the change in congestion between the Base Case and each Change Case to the affected sub-SPP entities, so it is reported in the tables as "unallocated." Generally, negative "Unallocated Congestion", which indicates a decrease in such congestion between the Base Case and the Change Case in question, indicates that LMPs changed more than quantities transacted between the sub-SPP entities reported.

It is important to note that the sum of estimated annual gross benefits across all the market participants (reported in section 4.2.3) in a state or in a balancing authority is not necessarily equal to the estimated annual gross benefits for the state (reported in section 4.2.1) or the estimated annual gross benefits for the balancing authority (reported in section 4.2.2), because of purchases and sales between market participants in a state or balancing authority. Such intra-state or intra-BA transactions cause the sum (across market participants) of purchases at load-weighted LMPs less the sum of sales at generation-weighted LMPs to be different than the state-level (or BA-level) purchases (at load-weighted LMPs) minus the state-level (or BA-level) sales (again, at generation-weighted LMPs).

### 4.2.1 State-Level Gross Benefits

Table 4-8 through Table 4-10 display the annual state-level gross benefit estimates for Change Cases I, IIA, and III. Tables 4-8 and 4-10 only provide estimates through 2013; state-level results were not extrapolated to 2014 – 2016, as the SPP-level gross benefits were. The tables can be summarized as follows:

- With two exceptions discussed below, estimated gross benefits are positive (or negative but less than $10 million in absolute value, which Ventyx considers to be essentially the same as zero) for all combinations of Change Case, year, and state.

- The exceptions are Kansas in 2013 in Change Case I and New Mexico in 2010 in Change Case III. The specific cause of these particular negative gross benefit estimates is not clear. Generally, negative annual gross benefits would be expected for entities (i.e., in this instance, states) with large net sales to the market; the lower locational marginal prices associated with a more efficient commitment and dispatch would yield lower revenues to such entities that, if large enough in absolute value, would offset the reduction in production costs attributable to the efficiency improvement. Negative gross benefits indicate the aggregation of the market participants in the state are harmed in the year by the market change considered in the Change Case, i.e., the sum of the operating margins earned by market participants in the state decrease as a result of the market change[9].

- The distribution of estimated gross benefits across states is fairly, though not exactly, consistent across Change Cases and years, especially for Change Cases I and IIA. Missouri, Nebraska, and Oklahoma have large positive estimated gross benefits in all Change Cases and years. Texas has large positive estimated gross benefits in Change Cases IIA and III in all years; Arkansas has consistently positive and occasionally large estimated gross benefits in all Change Cases and all years; and the other three states do not display a consistent pattern.

[9] Furthermore, if an entity (e.g., state, balancing authority, or market participant) does not include IPPs, and the entity's gross margins from sales to the market are credited to its retail customers in the form of lower retail rates, then negative estimated annual gross benefits indicates the entity's retail customers are harmed by the market change, i.e., retail rates charged to these customers would increase as a result of the market change.

**Table 4-8 Change Case I State-Level Gross Benefits (Million $)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Arkansas | 5 | 11 | 24 | 19 | 6 |
| Kansas | 16 | 8 | (1) | 19 | (10) |
| Louisiana | 3 | (0) | 3 | 5 | 1 |
| Missouri | 25 | 28 | 27 | 49 | 36 |
| Nebraska | 32 | 34 | 32 | 20 | 25 |
| New Mexico | 3 | 3 | (2) | (3) | (2) |
| Oklahoma | 28 | 28 | 50 | 66 | 57 |
| Texas | 3 | (5) | 7 | 4 | (9) |
| **Subtotal** | **113** | **108** | **140** | **179** | **104** |
| Unallocated Congestion | (12) | (48) | (46) | (55) | (29) |
| **Total** | **101** | **60** | **94** | **124** | **75** |

**Table 4-9 Change Case IIA State-Level Gross Benefits (Million $)**

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| Arkansas | 26 | 19 | 9 | 11 | 11 | 18 |
| Kansas | 11 | 13 | (2) | 20 | 36 | 28 |
| Louisiana | 1 | 3 | 0 | 8 | 3 | 4 |
| Missouri | 55 | 62 | 57 | 45 | 47 | 55 |
| Nebraska | 45 | 32 | 37 | 46 | 38 | 32 |
| New Mexico | (3) | 4 | (3) | 1 | (5) | (5) |
| Oklahoma | 64 | 81 | 70 | 107 | 84 | 108 |
| Texas | 11 | 5 | 30 | 18 | 50 | 53 |
| **Subtotal** | **211** | **219** | **197** | **257** | **264** | **294** |
| Unallocated Congestion | (40) | (59) | (65) | (121) | (126) | (142) |
| **Total** | **171** | **160** | **132** | **136** | **137** | **153** |

**Table 4-10 Change Case III State-Level Gross Benefits (Million $)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Arkansas | 5 | 7 | 4 | 3 | 10 |
| Kansas | (6) | 0 | 7 | 6 | (0) |
| Louisiana | (2) | 1 | (2) | (1) | 1 |
| Missouri | 8 | 21 | 33 | 36 | 27 |
| Nebraska | 17 | 19 | 15 | 13 | 11 |
| New Mexico | (1) | (24) | (1) | 7 | (1) |
| Oklahoma | 5 | 6 | 12 | 7 | 5 |
| Texas | 12 | 31 | 12 | 17 | 10 |
| **Subtotal** | **39** | **61** | **81** | **88** | **63** |
| Unallocated Congestion | (5) | (9) | 11 | 21 | 30 |
| **Total** | **34** | **52** | **92** | **109** | **93** |

The results summarized in Tables 4-8 through 4-10, as well as those for balancing authorities and market participants reported in sub-sections 4.2.2 and 4.2.3, were calculated based on the assumption that the ancillary service price is $15 / MWh. As discussed in Chapter 2, the gross benefit estimates at the sub-SPP level are somewhat sensitive to this assumed price. Table 4-11 displays the effects of alternative assumed AS prices on state-level gross benefit estimates for 2012 for Change Case II. States that are net purchases of ancillary services, such as Kansas, experience smaller gross benefits at higher assumed AS prices; states that are net sellers of ancillary services, such as Oklahoma, experience higher gross benefits at higher assumed AS prices; and states that mostly self-serve ancillary services, such as Missouri, show little impact of the AS pricing. This sensitivity test also reveals the range of the AS price impact. For example, estimated Kansas gross benefits are reduced approximately 70 percent between the high and low AS prices.

**Table 4-11 Change Case IIA 2012 State Gross Benefits – Sensitivity to AS Prices**

| | $5/MWh | $15/MWh | $25/MWh |
|---|---|---|---|
| Arkansas | 18 | 19 | 21 |
| Kansas | 20 | 13 | 6 |
| Louisiana | 4 | 3 | 2 |
| Missouri | 63 | 62 | 60 |
| Nebraska | 33 | 32 | 32 |
| New Mexico | 0 | 4 | 7 |
| Oklahoma | 77 | 81 | 85 |
| Texas | 4 | 5 | 5 |
| **Subtotal** | **219** | **219** | **219** |

### 4.2.2 Balancing Authority-Level Gross Benefits

Table 4-12 through Table 4-14 display estimated balancing authority-level gross benefits for Change Cases I, IIA, and III[10]. Again, gross benefit estimates were not extrapolated beyond 2013 for Change Cases I and III.

The tables display a pattern similar to the state-level tables. In particular, with one exception (SPS_BA in 2014 in Change Case II), the estimated gross benefits are positive (or negative but small) for all combinations of Change Case, year, and balancing authority. Moreover, the distribution of estimated gross benefits across balancing authorities is remarkably similar for Change Cases I and IIA. The distribution of estimated gross benefits for Change Case III shows little pattern at all. For Change Cases I and IIA, six balancing authorities have consistently large positive estimated annual gross benefits (in alphabetical order): AEPW_BA, KCPL, OGE_BA, OPPD, WFEC, and WRI_BA. In Change Case IIA, EDE,

[10] The suffix "_BA" is added to the names of balancing authorities that are different in composition than the corresponding market participant, e.g., OGE_BA includes the market participant OGE as well as other market participants.

GRDA, and NPPD also display consistently large positive estimated annual gross benefits. In Change Case III, only AEPW_BA consistently has large positive estimated annual gross benefits.

**Table 4-12 Change Case I Balancing Authority-Level Gross Benefits (Million $)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| AEPW_BA | 11 | 14 | 19 | 47 | 11 |
| EDE | (1) | 2 | 7 | 14 | 8 |
| GMOC | 3 | 6 | (3) | 5 | 4 |
| GRDA | 7 | 8 | 14 | 9 | 7 |
| KACY | 4 | 3 | 7 | 1 | (3) |
| KCPL | 28 | 28 | 20 | 29 | 26 |
| LES | (1) | (2) | (3) | (2) | (2) |
| NPPD | 6 | 11 | 1 | 6 | 8 |
| OGE_BA | 5 | 16 | 26 | 17 | 28 |
| OPPD | 21 | 23 | 20 | 16 | 19 |
| SECI_BA | 2 | 2 | 3 | 6 | 5 |
| SPS_BA | 8 | 10 | (3) | 9 | (5) |
| WFEC | 8 | 11 | 19 | 22 | 21 |
| WRI_BA | 10 | 9 | 6 | 29 | 12 |
| **Subtotal** | **110** | **142** | **133** | **208** | **139** |
| Unallocated Congestion | (9) | (82) | (39) | (84) | (64) |
| **Gross Benefit** | **101** | **60** | **94** | **124** | **75** |

Table 4-13 Change Case IIA Balancing Authority-Level Gross Benefits (Million $)

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| AEPW_BA | 39 | 48 | 26 | 32 | 30 | 40 |
| EDE | 12 | 13 | 12 | 12 | 14 | 18 |
| GMOC | 9 | 6 | 4 | 2 | 5 | 4 |
| GRDA | 20 | 15 | 10 | 15 | 13 | 18 |
| KACY | 6 | 2 | 4 | 2 | 4 | 3 |
| KCPL | 23 | 26 | 30 | 24 | 26 | 24 |
| LES | 2 | 2 | 4 | 1 | 2 | 3 |
| NPPD | 15 | 11 | 12 | 23 | 17 | 13 |
| OGE_BA | 22 | 16 | 26 | 41 | 37 | 57 |
| OPPD | 28 | 20 | 24 | 23 | 22 | 20 |
| SECI_BA | 5 | 5 | 9 | 3 | 1 | (2) |
| SPS_BA | (8) | 10 | (5) | (10) | (8) | (7) |
| WFEC | 22 | 21 | 26 | 32 | 29 | 36 |
| WRI_BA | 21 | 24 | 16 | 9 | 11 | 6 |
| **Subtotal** | **216** | **221** | **196** | **209** | **201** | **232** |
| Unallocated Congestion | (45) | (62) | (64) | (73) | (64) | (79) |
| **Gross Benefit** | **171** | **160** | **132** | **136** | **137** | **153** |

Table 4-14 Change Case III Balancing Authority-Level Gross Benefits (Million $)

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| AEPW_BA | 8 | 23 | 24 | 25 | 32 |
| EDE | (1) | (0) | 3 | 3 | 1 |
| GMOC | 1 | 2 | (2) | 0 | (1) |
| GRDA | 6 | 5 | 8 | 6 | 6 |
| KACY | (1) | (1) | 3 | (1) | (1) |
| KCPL | (1) | (0) | 3 | 2 | 3 |
| LES | 3 | 4 | 4 | 5 | 4 |
| NPPD | 7 | 7 | 5 | 3 | 5 |
| OGE_BA | (7) | (7) | (3) | (6) | (4) |
| OPPD | 8 | 8 | 7 | 6 | 3 |
| SECI_BA | 0 | 0 | 1 | 2 | 1 |
| SPS_BA | (7) | 50 | (4) | 8 | 2 |
| WFEC | (0) | 0 | 2 | 2 | 1 |
| WRI_BA | (5) | 2 | 8 | 11 | 5 |
| **Subtotal** | **11** | **92** | **59** | **66** | **57** |
| Unallocated Congestion | 23 | (40) | 33 | 43 | 36 |
| **Gross Benefit** | **34** | **52** | **92** | **109** | **93** |

### 4.2.3 Market Participant-Level Gross Benefits

Table 4-15 through Table 4-17 display market participant-level gross benefit estimates for Change Cases I, IIA, and III. Again, gross benefit estimates were not extrapolated for Change Cases I and III.

The tables display similar patterns to those shown in the balancing authority-level tables. In particular:

- Except for Wind IPPs (discussed below) and SPS in 2010 in Change Case III, estimated annual gross benefits are positive (or negative but small) for all combinations of Change Case, year, and market participant.

- Change Cases I and IIA display a similar distribution of estimated annual gross benefits across market participants. In particular, five participants have consistently large positive estimated annual gross benefits in both Change Cases (listed in alphabetical order): KCPL, IPPs, OGE, OPPD, and WFEC. The fact that the IPPs have consistently large positive estimated annual gross benefits is worth noting; this indicates that the increase in margins due to increased generation in a more efficient market outweighs the decrease in margins attributable to a reduction in LMPs in the more efficient market. Wind IPPs have consistently negative (and frequently large, i.e., greater than $10 million in absolute value) estimated gross benefits because their generation does not increase between the Base Case and each Change Case, but the LMPs they are paid go down with a more efficient market.

- In Change Case IIA, four additional market participants have consistently large positive estimated annual gross benefits: CSWS (AEPW), EDE, GRDA, and NPPD.

- In Change Case III, CSWS (AEPW) and IPPs have consistently large positive estimated annual gross benefits; with the exception of SPS in 2010, all other estimated annual gross benefits are less than $10 million in absolute value.

**Table 4-15 Change Case I Market Participant-Level Gross Benefits (Millions $)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| AECC | 2 | 4 | 4 | 3 | 1 |
| CSWS(AEPW) | 0 | 3 | 13 | 19 | 3 |
| EDE | (1) | 2 | 7 | 14 | 8 |
| GMOC | 3 | 6 | (3) | 5 | 4 |
| GRDA | 7 | 8 | 14 | 9 | 7 |
| GSEC | (3) | (4) | (2) | 4 | (3) |
| KACY | 4 | 3 | 7 | 1 | (3) |
| KCPL | 28 | 28 | 20 | 29 | 26 |
| KEPCO | (0) | 0 | 0 | 0 | 0 |
| KPP | 1 | 2 | 3 | 4 | 4 |
| LES | (1) | (2) | (3) | (2) | (2) |
| MIDW | (0) | 0 | 1 | 1 | 1 |
| NPPD | 6 | 11 | 1 | 6 | 8 |
| OGE | 11 | 24 | 34 | 25 | 34 |
| OMPA | (6) | (8) | (8) | (8) | (6) |
| OPPD | 21 | 23 | 20 | 16 | 19 |
| SECI | 2 | 2 | 2 | 6 | 5 |
| SPS | 13 | 18 | 7 | 16 | 7 |
| WFEC | 8 | 11 | 19 | 22 | 21 |
| WRI | 10 | 7 | 3 | 24 | 7 |
| IPPs | 21 | 14 | 19 | 7 | 22 |
| Wind IPPs | (2) | (4) | (9) | (11) | (9) |
| **Subtotal** | **120** | **145** | **145** | **188** | **152** |
| Unallocated Congestion | (19) | (85) | (51) | (64) | (78) |
| **Total** | **101** | **60** | **94** | **124** | **75** |

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**Table 4-16 Change Case IIA Market Participant-Level Gross Benefits (Million $)**

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| AECC | 6 | 5 | 5 | 2 | 4 | 8 |
| CSWS(AEPW) | 16 | 23 | 10 | 25 | 19 | 30 |
| EDE | 12 | 13 | 12 | 12 | 14 | 18 |
| GMOC | 9 | 6 | 4 | 2 | 5 | 4 |
| GRDA | 20 | 15 | 10 | 15 | 13 | 18 |
| GSEC | (3) | 2 | (2) | (0) | (0) | (1) |
| KACY | 6 | 2 | 4 | 2 | 4 | 3 |
| KCPL | 23 | 26 | 30 | 24 | 26 | 24 |
| KEPCO | 0 | 0 | 0 | 0 | 0 | (0) |
| KPP | 3 | 4 | 3 | 4 | 5 | 5 |
| LES | 2 | 2 | 4 | 1 | 2 | 3 |
| MIDW | 1 | 1 | 1 | 0 | (0) | (1) |
| NPPD | 15 | 11 | 12 | 23 | 17 | 13 |
| OGE | 26 | 20 | 28 | 44 | 40 | 60 |
| OMPA | (5) | (4) | (3) | (3) | (3) | (3) |
| OPPD | 28 | 20 | 24 | 23 | 22 | 20 |
| SECI | 5 | 5 | 9 | 2 | 1 | (2) |
| SPS | 5 | 20 | 6 | 6 | 1 | 15 |
| WFEC | 22 | 21 | 26 | 32 | 29 | 36 |
| WRI | 17 | 20 | 11 | 5 | 7 | 1 |
| IPPs | 33 | 28 | 33 | 44 | 53 | 54 |
| Wind IPPs | (10) | (12) | (9) | (16) | (8) | (20) |
| **Subtotal** | **226** | **224** | **213** | **246** | **243** | **276** |
| Unallocated Congestion | (55) | (64) | (80) | (110) | (106) | (124) |
| **Total** | **171** | **160** | **132** | **136** | **137** | **153** |

**Table 4-17 Change Case III Market Participant-Level Gross Benefits (Million $)**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| AECC | 5 | 4 | 6 | 4 | 11 |
| CSWS(AEPW) | 8 | 18 | 11 | 12 | 17 |
| EDE | (1) | (0) | 3 | 3 | 1 |
| GMOC | 1 | 2 | (2) | 0 | (1) |
| GRDA | 6 | 5 | 8 | 6 | 6 |
| GSEC | (1) | 5 | (0) | 0 | (1) |
| KACY | (1) | (1) | 3 | (1) | (1) |
| KCPL | (1) | (0) | 3 | 2 | 3 |
| KEPCO | 0 | 0 | 0 | 0 | 0 |
| KPP | 1 | 1 | 0 | 0 | 0 |
| LES | 3 | 4 | 4 | 5 | 4 |
| MIDW | 0 | 1 | 0 | 0 | 0 |
| NPPD | 7 | 7 | 5 | 3 | 5 |
| OGE | (9) | (9) | (6) | (9) | (7) |
| OMPA | 2 | 2 | 3 | 3 | 3 |
| OPPD | 8 | 8 | 7 | 6 | 3 |
| SECI | 0 | 0 | 1 | 2 | 1 |
| SPS | (6) | (35) | (4) | 8 | 0 |
| WFEC | (0) | 0 | 2 | 2 | 1 |
| WRI | (5) | 1 | 7 | 10 | 4 |
| IPPs | 17 | 16 | 22 | 16 | 19 |
| Wind IPPs | (1) | 2 | 0 | 0 | 3 |
| **Subtotal** | **28** | **25** | **69** | **69** | **62** |
| Unallocated Congestion | 6 | 28 | 24 | 40 | 31 |
| **Total** | **34** | **52** | **92** | **109** | **93** |

## 4.3 Change Case IV – Simplified Day-Ahead Market

A methodology for quantifying benefits under Change Case IV with a simplified Day-Ahead Market structure was discussed at length among the members of the MWG and CBTF. While the design is conceptually straightforward, there was considerable debate over whether the level of participation in this market would be sufficient to realize the potential benefits of the DAM and ASM structures. Several concerns were raised as to the efficiencies, volatility, and participation levels under this approach and ultimately, quantification of benefits was ruled out due to time constraints and the inability to determine a defendable approach. It was decided to provide a qualitative assessment of this market design option to summarize the discussion of the Cost Benefit Task Force.

The perceived benefits from this approach were centered primarily around making only minimal changes to processes currently in place for the EIS Market. Current Scheduling practices would remain in place, eliminating the need for additional software systems and staff for FTR or TSR implementation for congestion hedging. Only internal physical generation and load assets, including demand response, would continue to be eligible to bid in the Day-Ahead Market. The primary goal was to bring together generation sellers and load serving entities within the consolidated market boundary and allow SPP to both commit and dispatch all resources more efficiently.

Although the elimination of features does simplify the market design and would potentially reduce training costs, it likely would not result in significant cost savings in the implementation of software systems. Most systems for commitment and dispatch already support complex market features such as price-based schedules and virtual bids/offers as part of their core functionality. The simplified Day-Ahead Market design does reduce costs associated with changes to scheduling systems and/or implementation of FTR processes to support congestion hedging and may allow for an earlier market implementation date than the full Day-Ahead Market design option

Several concerns were voiced during the discussions of the Simplified Day-Ahead Market, which centered around the following factors:

1) No Dispatchable Transactions.
2) No Virtual Offers and Bids
3) Non-firm Transmission Service would still have Transmission Rights
4) Congestion being settled in both Day-Ahead and Real-time

The lack of participation by external parties through the use of dispatchable import transactions will likely increase internal SPP unit commitment, raising system costs. The lack of dispatchable export transactions would potentially reduce SPP revenues. In either case the removal of dispatchable transactions from the market design results in higher adjusted production cost and reduced benefits.

The lack of dispatchable transactions, along with no virtual offers and bids, will likely lead to over-commitment of SPP resources. This would result in day-ahead prices clearing higher than real-time prices. This could results in more load participating only in the real-time market and a drop in demand bids in the day-ahead market. This in turn could reduce day-ahead generation and cause day-ahead price to drop back below real time. This oscillation between day-ahead and real-time prices could lead to persistent inefficiencies as the market struggles to reach stability.

Allowing all priority schedules to maintain congestion hedging rights as well as continuing to allow schedules with congestion hedging rights to be submitted after settlement of the DAM reduces price certainty. Allowing Firm Schedules with full rights after the Day-Ahead Market has been settled may lead to the curtailment of scheduled Load that has cleared in Day-Ahead Market. This increases the risk for load and could reduce bid prices further in the Day-Ahead Market, again leading to fewer offers and further instability.

Allowing Non-Firm schedules to maintain congestion hedging rights also continues to put significant emphasis on ATC/AFC calculations and potential for parties making unnecessary reservations in order to maintain service options when trying to find buyers. If Non-firm energy is allowed to be traded within the market freely without reservations, then the use of OASIS and calculation of ATC for internal paths can potentially be eliminated, streamlining both internal SPP operations and that of Market Participants.

## 4.4 Other Factors

### 4.4.1 Locational Marginal Prices

Changes in Locational Marginal Prices due to the market designs are a minor factor in the SPP-wide gross benefits. SPP exports and imports from external markets are priced hourly at the generation-weighted SPP-wide hub price and the load-weighted SPP-wide hub price, respectively. Thus, SPP gross benefits reflect both changes in the pricing of SPP interchange as well as the volume of SPP exports and imports due to the relative market design. Since SPP external purchases and sales are very small compared to total SPP generation, the impact of external interchange comprises ranged between 5 and 8% of the SPP-wide gross benefits.

LMPs are a much greater factor in the gross benefits for sub-SPP entities (e.g., states), since adjusted production cost contain changes in levels and pricing of exports and imports both internal to SPP and external to SPP. Thus, exports and imports can be much larger relative to generation for sub-entities than at the aggregated SPP level. For example, in 2011, total Kansas generation decreases in Change Case II and more energy is purchased than in the Base Case. Generation cost decreases by $35 million but the market purchase cost increases by $17 million, showing that the impact of the LMP pricing can be significant.

More importantly, differences in LMPs between the Base Case and any of the Change Cases are a reflection of the degree to which each Change Case results in a more efficient commitment and dispatch than in the Base Case. This gain in operating efficiency is incorporated into the gross benefits at all levels.

Table 4-18 displays the load-weighted average 2012 on-peak hub prices for each of the load-serving market participants for the Base Case and Change Cases I, IIA, and III. It is critical to note that the LMPs for markets with “low” LMPs in the Base Case are frequently typically higher in Change Cases I and II than in the Base Case. This is because as a result of a more efficient commitment and dispatch in these two Change Cases, market participants in such markets increase their sales to other entities, and thus their generation. As these participants increase generation, they move up their supply (or marginal cost) curves to resources (or loading blocks) with higher marginal cost than what was dispatched in the Base Case. LMPs in these markets rise as a result; however, the margins these participants earn from such incremental sales are positive (or else they would not make the sales), so these participants benefit from the higher LMPs in their markets.

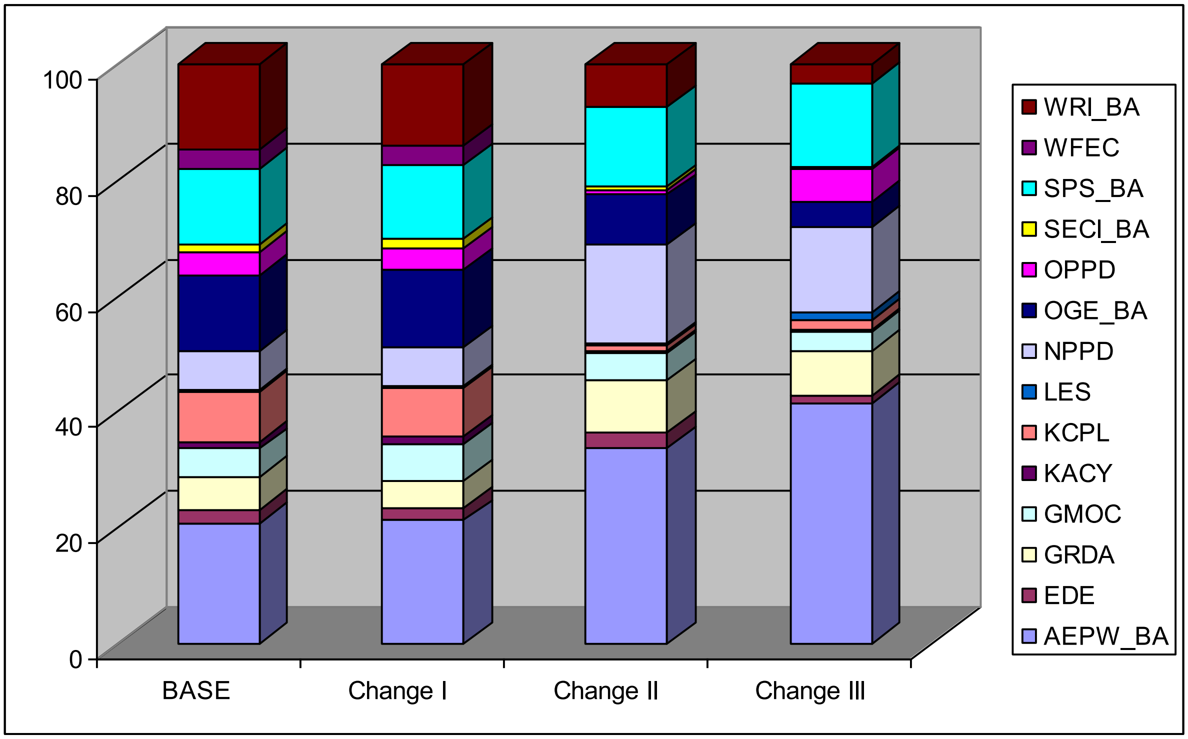
**Table 4-18 Average 2012 SPP Market On-Peak Load Hub Prices ($/MWh)**

| Areas | Base | CC I | CC II | CC III |
|---|---|---|---|---|
| AECC | 62 | 60 | 60 | 62 |
| CSWS(AEPW) | 58 | 57 | 58 | 58 |
| EDE | 67 | 58 | 58 | 70 |
| GMOC | 48 | 50 | 51 | 49 |
| GRDA | 50 | 54 | 55 | 50 |
| KACY | 51 | 52 | 52 | 50 |
| KCPL | 47 | 52 | 52 | 47 |
| LES | 54 | 59 | 58 | 53 |
| MIDW | 82 | 76 | 76 | 82 |
| NPPD | 53 | 58 | 58 | 53 |
| OGE | 74 | 65 | 65 | 74 |
| OMPA | 72 | 62 | 62 | 72 |
| OPPD | 55 | 59 | 59 | 54 |
| SECI | 73 | 71 | 70 | 72 |
| SPS | 74 | 74 | 73 | 74 |
| WEPLKS | 75 | 73 | 72 | 74 |
| WFEC | 74 | 66 | 67 | 74 |
| WRI | 62 | 53 | 54 | 61 |

### 4.4.2 Ancillary Service Market – Spinning Reserve and Regulation-Up Services

Another factor, Ancillary Services for Spinning reserve and Regulation-Up, do not directly impact the calculation of SPP-level gross benefits because AS payments and revenues net to zero at a SPP level. However, AS payments and revenues will affect gross benefits for sub-SPP entities because a sub-entity may provide more AS than required, thus selling the additional AS for additional market revenues. Conversely, a sub-entity may purchase some or all of its AS requirement from other SPP sources and incur a payment at market rates. Thus, the distribution of spinning reserve and regulation-up across states, BAs and Market Participants, while advantageous from the perspective of economic efficiency, may have a significant impact on the benefits of a particular market design. Figure 4-9 presents estimates for 2012 for the Base Case and the three Change Cases of the share of total spinning reserves provided by each of the Balancing Authorities.

**Figure 4-9 Distribution of 2012 Ancillary Services across Balancing Authorities (%)**




** Values are in Percent of Ancillary Service Requirement*

## 4.5 High Wind Impacts

Wind generation expansion will play a major role in the Southwest Power Pool during the upcoming decade. The SPP generation queue is overflowing with interconnect requests for wind projects and feasibility studies are in progress which contemplate significant wind penetrations that approach total SPP load forecasts. The recently released draft of the SPP EHV Transmission Overlay Report contained an "expected" wind capacity assumption of 6,700 MW in the SPP footprint by 2017 and a "high" wind assumption of 10,500 MW by 2017. This compares to 4,211 MW of wind modeled in this study of future SPP market design. More aggressive assumptions for SPP wind development over the time horizon of this study could have a significant impact on the benefits of adding a Day-Ahead Market (DAM) and/or Ancillary Service Market (ASM) in SPP. While attempting to quantify the effect of high wind on benefits is outside the scope of the current study, a qualitative discussion of the impact of a high wind scenario can provide valuable insights for the consideration of market design changes.

A high level of wind generation poses significant obstacles to efficient unit commitment. Markets without the ability to forecast day ahead wind output and make rational commitment decisions will have substantial inefficiencies in unit operations that result in high costs to participants and ultimately to consumers. Even with a robust Day-Ahead Market, the error in current wind forecasting methods creates substantial difficulties for hour-ahead unit commitment decisions. Without a process to account for anticipated wind levels well in advance of hourly operations, significant over-commitment of resources will likely be necessary to protect against less-than-expected wind generation.

A key operational consideration for a high wind scenario is dealing with wind variability. The most effective means of handling variability is to increase the balancing footprint responsible for absorbing the wind output. The large-scale development of wind resources would quickly overwhelm the current balancing areas in the wind producing regions, requiring a move toward a consolidated SPP balancing area. This high variability of wind will also result in increased requirements for ancillary services such as spinning and non-spinning reserve. The addition of an Ancillary Services Market as modeled in this market design study will likely yield substantially higher benefits under high wind scenarios that require increased operating reserves. The ability to economically manage reserves over larger footprints will become increasingly important with high wind expansion.

There is a significant component to handling wind variability that falls between traditional regulation markets and contingency reserve requirements. Wind variations over 5 to 10 minute intervals can best be addressed through economic response within a "fast market" framework, where a substantial portion of the market generation is responding to economic price signals and can be effectively used to absorb wind volatility. The addition of a Day-Ahead Market with centralized unit commitment is a key step in achieving sufficient market participation to meet this need.

Another aspect of an SPP high wind generation scenario is the coincident transmission system expansion needed to move this generation to load centers. In addition to allowing the transport of wind generation, the current EHV transmission overlay designs will greatly enhance the ability to move power across the SPP system as needed to meet load with low cost resources. The addition of a Day-Ahead Market in SPP will allow system operators to take full advantage of reduced congestion to lower overall unit costs through optimized unit commitment.

Finally, providing the congestion hedging tools such as FTRs or TSRs will address potentially severe short term congestion caused by the rapid development of wind resources. Given the relatively long time frame to complete substantial transmission upgrades there will likely be periods of significant local congestion caused by wind coming on-line in advance of critical transmission and by transmission line outages necessary to complete upgrades. Allowing mechanisms for acquiring transmission rights to hedge exposure to congestion will provide significant benefit for market participants during transition periods.

Virtually all the impacts of high wind scenarios highlight the need for robust market designs including a Day-Ahead Market and Ancillary Service Market to efficiently incorporate wind generation. In many cases high wind penetrations may not even be achievable without the implementation of these market design components. While further studies should be undertaken to better quantify the benefits of robust market design elements under high wind assumptions, the addition of a Day-Ahead Market and Ancillary Service Market are likely critical factors in realizing the full benefit of new wind development.

The production cost modeling of the Base Case and Change Cases I – III does not reflect the possibility of any increase in ancillary service requirements associated with even the 4,211 MW of wind capacity additions included in those cases. As such, the estimates of gross benefits for Change Cases II and III may understate the true gross benefits, since the corresponding market designs may be able to more efficiently accommodate the increased ancillary service requirements than the Base Case market design.

# 5 Appendices

# ATRR Forecast Methodology

***19-Jan-12***

**INTRODUCTION**

**Cost Allocation History at Southwest Power Pool**

- Pre 2005 – Participant Funding
- 2005 – Traditional Base Plan Funding
- 2008 – Balanced Portfolio with Transfers
- April 2009 – SPPT Report recommends Highway Byway
- October 2009 – RSC approves 100% Highway Byway
- June 2010 –
  - Upgrades issued Notifications To Construct (NTC) before June, 2010 are Traditionally Base Plan Funded
  - Upgrades issued NTCs after June, 2010 are Highway Byway Funded

**ATRR FORECAST CONCEPTS AND PROCEDURAL FLOW**

**1. Upgrade Types**

a. Original Base Plan Funding
  § NTCs for these projects must have been issued before June 19, 2010
b. Highway/Byway Base Plan Funding
  § Projects given an NTC after June 19, 2010
c. Zonal
  §Costs for projects built by a TO for Zonal issues only or are 100 kV or below are allocated directly to the host zone
d. Balanced Portfolio
  § A select group of projects issued NTCs during 2009 and early 2010
  § Selected based on results from the SPP Transmission Expansion Plan (STEP)
e. Priority Projects
  § A select group of projects issued NTCs during the latter half of 2010
  § Selected based on results from the SPP Transmission Expansion Plan (STEP)
  § Use the Highway/Byway Cost Allocation methodology
f. For upgrades that do not qualify would fall to the Transmission Service requestor.

**2. Calculate ATRR**

a. The ATRR is the amount of revenue the TO is authorized to collect by FERC through the Open Access Transmission Tariff each year in this forecast.
  § ATRR ($/yr) = Upgrade Investment ($) * Net Plant Carrying Charge (%/yr) and depreciated in years after its in-service year, this methodology is applied in the same for all upgrades in this forecast
b. The NPCC used to calculate the ATRR of a given upgrade is the NPCC of the host zone for that upgrade.
c. Load Ratio Share (LRS)
  § The Load Ratio Share of 2010 actual loads (as maintained by SPP Settlements) was KEPT CONSTANT and used for all future years.
  § as Posted in the Revenue and Rates Requirement (RRR) file as posted on the SPP OASIS site.
d. MW-Mile %
  § MW-Mile is a beneficiatry impact calculation based upon load flow reduction % of each zone after the new upgrade is placed-into-service in the load flow model.
  § Used with Originally Base Plan Funded projects only.

**3. Cost Allocation Methods to Zones**

a. Original Base Plan Funded (2/3 : 1/3)
  § Zonal Assignment ($/YR) = 67% * ATRR ($/yr) * MW-Mile (%)
  § Regional Assignment ($/YR) = 33% * ATRR ($/yr) * LRS (%)
  § Total ATRR ($/YR) = Zonal + Regional
b. Highway/Byway Base Plan Funding (Priority Projects are included in this type)
  § Costs allocated based on the voltage level of the given upgrade.
  § If the upgrade is a transformer, use the voltage of the low side winding.
  § If the operating voltage (kV) > 300 kV
    Zonal ($/yr) = 0 %
    Regional ($/yr) = 100% * ATRR ($/yr) * LRS (%)
    Total ATRR ($/yr) = Zonal ($/yr) + Regional ($/yr)
  § If 100 kV <= voltage (kV) <= 300 kV
    Zonal ($/yr) = 67% * ATRR ($/yr)
    Regional ($/yr) = 33% * ATRR ($/yr) * LRS (%)
    Total ATRR ($/yr) = Zonal ($/yr) + Regional ($/yr)
  § If voltage (kV) <= 100 kV
    Zonal ($/yr) = 100% * ATRR ($/yr)
    Regional ($/yr) = 0 % ATRR
    Total ATRR = Zonal + Regional
c. Balanced Portfolio
  § All upgrade costs are 100% Regional.
  § Total ATRR ($/yr) = ATRR ($/yr) * LRS (%)
d. Zonal
  § Upgrades are allocated 100% to the Host Zone
  § Total $ATRR_{host}$ = ATRR ($/yr)
  § Total $ATRR_{other\ zones}$ = 0 ($/yr)

**4. Depreciation**

a. 40 year straight line depreciation was used representing a 2.5% depreciation rate.

**5. Balanced Portfolio Transfers**

a. Transfers apply only to upgrades associated with the Balanced Portfolio
b. A "phase-in" of 20% per year in starting in year 2012 is applied until year 2016 when the transfers reach their estimated total of $94.8M/yr
c. Transfers based on Dr. Mike Proctor's Balancing Transfers total 10 year present value model.
d. In the forecast, transfers are applied after depreciation but before discounting.

**6. Construction Work In Progress (CWIP)**

a. Amount of $ to be recovered on upgrade prior to the upgrade going into service.
b. CWIP values used are associated with Balanced Portfolio and Priority Projects.

**7. Discounting to 2012** *Net Present Value (NPV)*

a. Discounting each year's future depreciated cost back to present dollars.

b. Based on an 8% discount rate.

**8.** **Rates and Revenue Requirements (RRR) Files, per Attachment H, where current ATRRs are found in the Tariff**

a. Attachment H is the Annual Transmission Revenue Requirement for Network Integration Transmission Service

b. Attachment H accounts for all upgrades which are already in-service and have been filed with SPP in rates.

c. Attachment H, Table 1, Column 3 – Zonal ATRR

§ a.k.a. – "Legacy Rates"

§ This amount is added to its respective zone for each year of the forecast.

d. Attachment H, Table 1, Column 4 - Base Plan Zonal ATRR, for Upgrades with NTCs issued before June 19, 2010, the MW-mi componet

e. Attachment H, Table 1, Column 5 - Base Plan Zonal ATRR, for Upgrades with NTCs issed after June 19, 2010, the zonal component of Highway Byway cost allocation

f. Attachment H, Table 1, Column 6 - ATRR Reallocated to Balanced Portfolio Region-wide ATRR otherwise know as the Balancing Transfers

g. Attachment H, Table 2, Row 5 shows the total Region-wide ATRR. This total is multiplied by each zone's Load Ratio Share to determine the zone's Region-wide ATRR

**9. On Next Tab, please find the "Master Summary (ITPNT)", this workbook is shown in 6 tables. An overview of each table is shown below:**

| |
|---|
| TABLE 1 - Yearly Incremental ATRR Totals by summing cost allocation type summary tabs |
| TABLE 2 - Depreciated upgrades (2.5% straightline - 40 year life assumed) with a 6 mo time shift from assumed January in-service date of in-service year |
| TABLE 3 - Inclusion of Balanced Portfolio Transfers and Cost Allocation of Total of Transfers |
| TABLE 4 - Construction Work In Progress (CWIP) added here, only CWIP from Balanced Portfolio and Priority Projects is estimated and included |
| TABLE 5 - Attachment H, Table 1, Column 3 "Legacy Tariff Rate" and 2006-2011 ATRRs added here |
| TABLE 6 - Present Value of 40 years of depreciated and shifted ATRRs summed here (8% Discount Rate applied here) |

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# Regional Allocation Review Task Force Report

January 2012

Southwest Power Pool

## Regional Allocation Review Task Force Report

## Executive Summary

This Report contains the recommendations of the Regional Allocation Review Task Force (RARTF) as to how Southwest Power Pool (SPP) should review the Highway/Byway transmission cost allocation methodology per Attachment J, Section III.D of SPP's Open Access Transmission Tariff (OATT). The RARTF recommends that this review be called the "Regional Cost Allocation Review".

The RARTF makes a number of recommendations as to how SPP should conduct the Regional Cost Allocation Review. This includes a recommendation of applying ten principles, used by the RARTF, as a guide to conducting the review. These principles include: simplicity; acknowledgment of the "roughly commensurate" legal standard; equity over time; the use of the best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects. Applying these principles the RARTF recommends that:

- The review contains two evaluations; (1) as required by SPP's OATT, the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a Notification to Construct (NTC) has been issued since June 2010 and (2) the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a NTC has been issued since June 2010 plus Board approved transmission projects that have received an Authorization to Plan (ATP) with in-service dates of ten years or less. The RARTF recommends a 0.75 weighting for ATP projects due to the less certain nature of these projects as well as their costs and benefits.

- The review be integrated with the 10 Year ITP Plan schedule and be undertaken after its completion.

- The review use the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted.

- To remain consistent with SPP's OATT, the review use a 40-year horizon to evaluate all transmission projects in the review.

- The information used in the review be the most up to date and that all assumptions be vetted through SPP's stakeholder process.

- Through the work of the Economic Studies Working Group (ESWG) certain benefits be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits.

Additionally, the Report contains a recommendation regarding the establishment of a Benefit to Cost (B/C) threshold. The recommended B/C threshold would be the basis for SPP staff and stakeholders to evaluate remedies for any zone falling below the threshold. Specifically, the Report recommends:

- That a threshold be set at a B/C ratio of 0.8. With this benchmark, if the review shows that any zones fall below this threshold; SPP Staff will study and report on potential remedies for these zones.

- A list of recommended mitigation remedies for SPP staff to study and report for any zone below the 0.8 threshold. The recommended list of remedies in preferential order includes, but is not limited to: (1) acceleration of planned upgrades; (2) issuance of new upgrades; (3) applying highway funding to one or more byway projects; (4) applying highway funding to one or more seams projects; (5) zonal transfers (similar to balanced portfolio transfers) to offset costs or a lack of benefits to a zone; (6) exemptions for cost associated with the next set of projects; and (7) changes to cost allocation percentage.

Finally, the Report contains a recommended timeline and action plan with four additional recommendations for implementation of the Regional Cost Allocation Review process.

## Regional Allocation Review Task Force: Recommendations

In approving the Highway/Byway cost allocation methodology for the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO), the Federal Energy Regulatory Commission (FERC) also approved a requirement that SPP conduct a review of the "reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years."[1] This review is required to "determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct (NTC) issued after June 19, 2010 to each pricing Zone within the SPP Region."[2] Thus, the purpose of this analysis is to measure the "cost allocation impacts" of SPP's Highway/Byway methodology by zones. The review is hereinafter referred to as the "Regional Cost Allocation Review."

SPP's Open Access Transmission Tariff (Tariff or OATT) specifically requires that "the Markets and Operations Policy Committee (MOPC) and Regional State Committee (RSC) will define the analytical methods to be used" in conducting the Regional Cost Allocation Review.[3] As a result, the Regional Allocation Review Task Force (RARTF) was created as part of the SPP stakeholder process to develop the "analytical methods" used for the review.

The RARTF membership is composed of three representatives from the RSC, three SPP Members, and one member from the independent SPP Board of Directors. The RSC President Jeff Davis and MOPC Chairman Bill Dowling jointly selected the members of the RARTF. The members of the RARTF are:

| RARTF Members | |
|---|---|
| Chairman Michael Siedschlag | Nebraska Public Review Board |
| Vice-Chairman Richard Ross | American Electric Power |
| Commissioner Thomas Wright | Kansas Corporation Commission |
| Commissioner Olan Reeves | Arkansas Public Service Commission |
| Bary Warren | Empire District Electric |
| Philip Crissup | Oklahoma Gas & Electric |
| Harry Skilton | SPP Board of Director |

Pursuant to the mandate in the RARTF Charter, the RARTF prepared this White Paper which includes its recommendation as to how to define the "analytical methods" to be used in the Regional Cost Allocation Review.

## SECTION 1: OVERVIEW

### 1.1 Overview of SPP Tariff Requirements

Attachment J, Section III.D to the SPP OATT establishes a four-step process for the Regional Cost Allocation Review. These steps are:

[1] Attachment J, Section III.D.1 of SPP's OATT.
[2] Attachment J, Section III.D.2 of SPP's OATT.
[3] Attachment J, Section III.D.4(i) of SPP's OATT.

**Step 1:** One year prior to each three-year planning cycle (starting in 2013) the MOPC and RSC will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the RSC and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.[4]

**Step 2:** For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with NTC issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the RSC shall determine the cost allocation impacts utilizing the analysis specified in Section III.8.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J.[5]

**Step 3:** The Transmission Provider shall review the results of the cost allocation analysis with SPP's Regional Tariff Working Group (RTWG), MOPC, and the RSC. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.[6]

**Step 4:** The Transmission Provider shall request the RSC provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.[7]

## 1.2 Overview of RARTF Charter

In addition to the requirements contained in the SPP's OATT, the RARTF's Charter contains additional work and deliverables for the RARTF. Specifically, the Charter states:

> The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP Staff guidance as to the Task Force's expectation for the threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.

Additionally, the Charter contains a list of key deliverables for the RARTF which states:

> <u>The RARTF scope of work and key deliverables include the following:</u>

[4] *Id.*
[5] Attachment J, Section III.D.2 of SPP's OATT.
[6] Attachment J, Section III.D.3 of SPP's OATT.
[7] Attachment J, Section III.D.4 of SPP's OATT.

> 1. Development of and recommendation for a methodology to be used to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.
>
> 2. Develop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.
>
> 3. Develop a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.
>
> 4. Final report containing such recommendations to be prepared and issued by December 20, 2011.

### 1.3 Overview of Legal Standards

Pursuant to the RARTF Charter, the RARTF has been tasked to "[d]evelop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority." In researching and discussing how to establish a threshold, SPP staff and the RARTF reviewed and considered the legal significance and relevance of the 7th Circuit decision in the *Illinois Commerce Commission (ICC) v. FERC*.[8]

In this review, the RARTF found that the term "roughly commensurate" was used for the first time by the 7th Circuit in the *ICC v. FERC* case. Other than the *ICC* case, the term "roughly commensurate" has never been used in an appellate case reviewing a FERC order, nor has FERC ever used the term prior to the *ICC* remand. Since the *ICC* opinion was issued, FERC cited the 7th Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology,[9] Midwest Independent Transmission System Operator's (MISO) multi-value project ("MVP"), and California Independent Transmission System Operator's convergence bidding proposal, although none of these orders elaborates on the exact meaning of "roughly commensurate." Additionally, FERC, subsequent to the establishment of the RARTF, used the term in Order No. 1000,[10] as well as FERC's Orders on Rehearing for SPP's Highway/Byway cost allocation methodology[11] and on MISO's MVP cost allocation methodology. Specifically, as quoted by FERC in its October 20, 2011 Order on Rehearing in, the 7th Circuit stated that the

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8 576 F.3d 470 (7th Cir. 2009).
9 *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 (2011).
10 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011).
11 *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 (2011).

legal standard is that "an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities."[12]

The RARTF notes a couple of important aspects of the orders from the 7th Circuit and FERC dealing with the "roughly commensurate" standard. First, it appears that "roughly commensurate" is not "cost-beneficial" so that something less than a 1.0 Benefit/Cost (B/C) ratio may comply with the standard and that FERC has said that "the question becomes not whether the Highway/Byway methodology matches cost to the benefits on a utility-by-utility or zone-by-zone basis, but whether it will provide sufficient benefits to the entire SPP region to justify a regional allocation of costs."[13]

Additionally, the RARTF notes that the *ICC* case and the precedent on which the 7th Circuit relied in its decision did articulate certain principles that a cost allocation method must satisfy. These include:

- A cost allocation mechanism may tracks costs less than perfectly.
- A cost allocation mechanism need not calculate benefits to the last penny or, for that matter, to the last million or ten million or perhaps hundred million dollars.
- A pricing scheme may not require payments from those that derive no benefits or benefits that are trivial in relation to the costs.
- Rates must reflect, to some degree, the costs actually caused by the customer who must pay them.
- Benefits do not necessarily need to be quantified, but there must be an articulable and plausible reason to believe that benefits received by customers are at least roughly commensurate with the costs allocated to customers.
- FERC must compare the costs assessed against a party to the burdens imposed or benefits drawn by that party.

The RARTF considered the research of the *ICC v. FERC* and related cases, as well as subsequent FERC orders citing the 7th Circuit's "roughly commensurate" standard, in the task force's deliberation and conclusions found in Section 4 below.

### 1.4 Cost Allocation Challenges for Transmission Upgrades

The allocation of costs for public projects with significant and widespread public benefits is very challenging and difficult. This is particularly true for electric transmission projects, as has been stated by the FERC:

> Determining the costs and benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple systems and therefore may have multiple beneficiaries. At the same time, the expansion of regional

[12] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 22 (2011).
[13] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 22 (2011).

> power markets and the increasing adoption of renewable energy requirements have led to a growing need for transmission projects that cross multiple utility and RTO systems. There are few rate structures in place today that provide the allocation and recovery of costs for these intersystem projects, creating significant risk for developers that they will have no identified group of customers from which to recover the cost of their investment.[14]

The difficulties of implementing cost allocation methods for transmission projects are evident. Because of the many challenges associated with regional transmission cost allocation and its accompanying critics, it is critical that SPP's Regional Cost Allocation Review be based upon reasonable, sound, and defensible methods.

## SECTION 2: SPP STAFF RESEARCH

### 2.1 SPP Staff Research

In preparing for the work of the RARTF, SPP staff gathered information that would be helpful to SPP stakeholders in developing analytical methods to review both the cost and the benefits of SPP transmission projects. SPP staff researched how transmission costs are allocated in different regions of the United States and the various ways that benefits are calculated for transmission projects. A summary of SPP staff's research is provided below. The research helps to illustrate the difficulty of allocating cost of transmission projects and the number of methods available for use in measuring the benefits of transmission projects. The RARTF believes that this information can help SPP stakeholders to develop sound analytical methods to determine the impacts of SPP's Highway/Byway cost allocation methodology that are reasonable, sound, and defensible.

### 2.2 Transmission Cost Allocation Methods in the United States and SPP

The difficulties of transmission cost allocation are demonstrated by the wide variety of methods used in the various regions of the United States. This difficulty is further demonstrated by the inability of most regions to adopt transmission cost allocation methodologies for regional overlay projects. This is effectively illustrated in Figure 1, below, which presents a summary of the various transmission cost allocation methods in the United States, as prepared by the Brattle Group.

[14] *Transmission Planning Processes Under Order No.* 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).

## Summary of Current Cost Allocation Methodologies

LP = License Plate Tariffs; PS = Postage Stamp Tariffs or Postage Stamp Allocation; M = Merchant Lines; GI = Generation Interconnection Tariffs;
✓ = workable approach; n/a = workable approach not yet available

| RTO/ Region | General Tariff Methodology | Reliability | "Economic" Projects | Renewables | Regional/Overlay Projects |
|---|---|---|---|---|---|
| CAISO | PS 100% ≥200kV; otherwise LP or M | ✓ | ✓ | ✓ GI and location-constrained resource tariff (Tehachapi) | ✓ Not specifically discussed, but 100% PS of all network facilities |
| ERCOT | PS or M | ✓ | ✓ | ✓ CREZ (100% PS) | ✓ Not specifically discussed, but 100% PS of all network facilities |
| SPP | Before 6/19/10: 33% PS+67% LP w/ Beneficiary Analysis<br>After 6/19/10: 100% PS ≥300kV; 33% PS+67% LP >100kV to <300kV; 100% LP ≤100kV | ✓ | ✓ | ✓ GI; Highway/Byway PS treatment | ✓ Highway/Byway PS treatment |
| Southeast | LP (utility specific tariffs) | ✓ | n/a | n/a (GI only) | n/a |
| ISO-NE | PS 100% ≥115kV; otherwise LP or M | ✓ | too narrowly defined | n/a (GI only) | n/a |
| PJM | PS sharing 100% ≥500kV; otherwise LP allocation (beneficiary pays) or M | ✓ | too narrowly defined | n/a (GI only) | n/a |
| MISO | PS sharing 20% ≥345kV; rest LP allocation (beneficiary pays) or M; MVP approach | ✓ | too narrowly defined | Multi Value Project ("MVP") PS treatment | MVP PS treatment |
| PJM-MISO | Sharing of reliability project based on net flows/beneficiaries | ✓ | too narrowly defined | n/a | n/a |
| NYISO | LP allocation (based on beneficiary pays) or M | ✓ | too narrowly defined | n/a (GI only) | n/a |
| WECC (non-CA) | LP; often with cost allocation based on co-ownership | ✓ | ✓ (differs across WECC subregions) | ✓ GI (*e.g.*, BPA open season); under discussion in WREZ | n/a – under discussion in WREZ |

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**Figure 1. Cost Allocation Methodologies of Regions of the United States[15]**

As has been done in the various regions of the United States, SPP has developed a variety of cost allocation methodologies. Since SPP's recognition as an RTO and the establishment of the RSC,[16] the SPP Region has developed and implemented differing transmission cost allocations in an evolutionary manner through the RSC. These methods are summarized below in Figure 2.

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[15] Reprinted with permission by The Brattle Group, Inc.: Delphine Hou and Johannes P. Pfeifenberger, "Financing Transmission Expansion: The Impact of Cost Allocation," presented to EUCI, March 8-9, 2011. (Slide 9 updated July 2011).

[16] Through SPP's governance structure, the SPP RSC has been delegated authority to establish cost allocations that the SPP Board of Directors must file at FERC as a Section 205 filing of under the Federal Power Act.

| Summary of Southwest Power Pool's Cost Allocation Methods | | | | | | |
|---|---|---|---|---|---|---|
| **Date Range** | **Upgrade Type** | **Zonal** | **Regional** | **Customer** | **Sponsor** | **Comments** |
| Pre-2005 | Pre-BPF Needs | 100% | | | | Before regional cost sharing |
| | Other | 100% | | | | |
| Original Base Plan Funding 2005 - NTC Issue Date of June 19, 2010 | Sponsored | | | | 100% | |
| | Reliability | 67% | 33% | | | Based on Need-By Date - Zonal on MW-MI beneficiary % |
| | Generation Interconnection | | | 100% | | |
| | NITS Service Upgrade costs covered by Safe Harbor limit | 67% | 33% | | | Zonal on MW-MI |
| | NITS Service Upgrade costs *NOT* covered by Safe Harbor limit or did not qualify for Base Plan Funding | | | 100% | | Safe Harbor Limit: E&C Cost <=$180,000/MW Requested |
| | PtP Service Upgrade costs that do not qualify for Base Plan Funding | | | 100% | | Costs in excess of PtP Rate |
| | Balanced Portfolio | | 100% | | | |
| | Sponsored | | | | 100% | |
| NTC Issue Date of June 19, 2010 through the Present | Reliability/Economic Upgrade Voltage | 0% | 100% | | | |
| | Reliability/Economic Upgrade Voltage over 100 kV and under 300 kV | 67% | 33% | | | |
| | Reliability/Economic Upgrade Voltage under 100 kV | 100% | 0% | | | |
| | Upgrades related to delivery of power from a Wind Projects Outside TSR Customer's load Zone and less than 300 kV | | 67% | 33% | | |
| | Upgrades related to delivery of power from a Wind Projects greater than than 300 kV | | 100% | | | |
| | NITS Service Upgrade costs covered by Safe Harbor limit | *Voltage Dependent:* >300kV=100% Regional, 100kV-299KV=33% | | | | "Highway/Byway" method, upgrade >300kV 100% Regional in all cases |
| | NITS Service Upgrade costs *NOT* covered by Safe Harbor limit or did not qualify for Base Plan Funding | | | 100% | | |
| | PtP Service Upgrade costs that do not qualify for Base Plan Funding | | | 100% | | Costs in excess of PtP Rate |
| | Generation Interconnection | | | 100% | | |

**Figure 2. SPP Cost Allocation Methods**

The most recent method established by the RSC and approved by FERC is the Highway/Byway cost allocation methodology. The Highway/Byway method assigns 100% of all 300 plus kV transmission upgrades' Annual Transmission Revenue Requirement (ATRR) to the SPP zones on a regional basis using the Load Ratio Share (LRS), as a percentage of the whole of regional loads, of each zone multiplied by the total ATRR of the new upgrade. New upgrades with a voltage rating between 100 kV and 300 kV are allocated 33% to all zones in the region on a LRS basis and 67% to the host zone's Transmission Customers (TCs). New upgrades under 100 kV are allocated 100% to the TCs of the host zone.

| Highway Byway Cost Allocation Overview | | |
|---|---|---|
| **Upgrade Voltage** | **Region Pays** | **Local Zone Pays** |
| 300 kV and above | 100% | 0% |
| above 100 kV and below 300 kV | 33% | 67% |
| 100 kV and below | 0% | 100% |

**Figure 3. Highway/Byway Cost Allocation Overview**

The ATRRs assigned to the zones are collected from their respective TCs using the previous year's 12 month Coincident Peak LRS.

Cost allocation of new construction is the focus of Attachment J to the SPP OATT. The recovery of the ATRR is through Schedule 11 of the OATT and booked by each zone in Attachment H of the OATT.

## 2.3 Methods of Measuring Transmission Upgrade Benefits

Just as SPP staff's research found that many different transmission cost allocation methods are used in the United States, staff's research has found that a number of methods can be used to determine the amount of benefits transmission projects provide to society.

Based upon this research, the RARTF recommends that the benefits to be assessed for the Regional Cost Allocation Review should not be limited to a single methodology. Instead, the RARTF recommends that in order to study a broader scope of benefits in the region, multiple methodologies should be used. Staff believes that a very narrow focus on only one benefit type over a very narrow timeframe does not provide a large enough sample size to reasonably determine the impact of SPP's Highway/Byway cost allocation methodology. Additionally, because different benefits are valued differently by various people and segments of society, the RARTF believes that in order to provide for a reasonable, fair, and acceptable review of the Highway/Byway, numerous methods should be used in this review as opposed to a single narrowly- focused method. The RARTF's recommendations are outlined in this Report.

As illustrated below in Figure 4, a number of benefits can be gained from transmission projects.

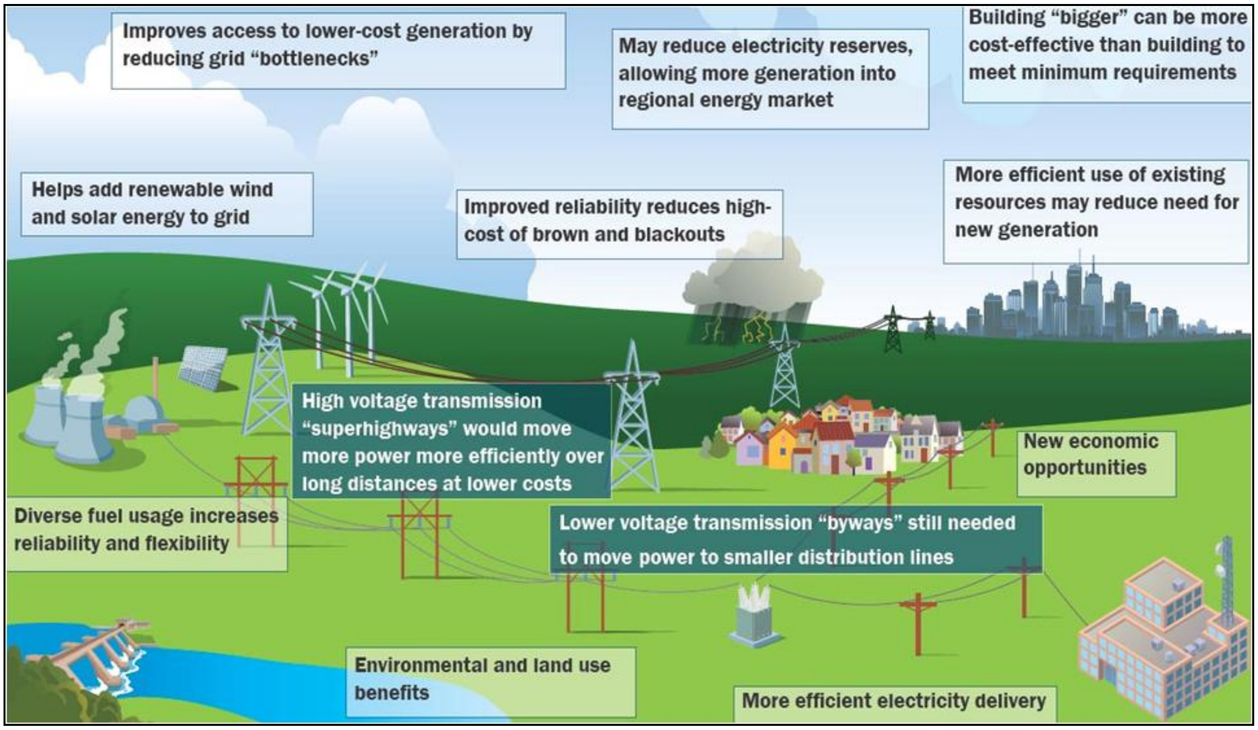


**Figure 4. Benefits of a Robust Transmission System**

SPP staff’s research has found that a number of benefits exist that can be measured under a benefit to cost analysis. Although the RARTF does not recommend using all of these benefits for the Regional Cost Allocation Review, they are included below for educational purposes.

***Adjusted Production Cost***

Adjusted Production Cost (APC) has quickly become the “standard” that utilities are employing to measure the benefit of transmission expansion. APC is a measure of the impact on production cost savings by Locational Marginal Price (LMP), taking into account purchases and sales of energy between areas of the transmission grid. APC is determined using a production cost modeling tool that accounts for 8,760 hourly commitment and dispatch profiles for one simulation year. Nodal analysis from the production cost model is aggregated on a zonal basis.

APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that are directly related to energy production by generating resources in the SPP footprint.

References to an APC-based B/C (Adjusted Production Cost-based Benefit-to-Cost ratio) refer to the reduction in APC due to a project divided by the cost of that project.

***Meeting State and Utility Goals and Standards***

This metric links a transmission project to meeting the goals and standards set forth by the utilities and states that are in a study analysis. Simply put – does a transmission project or portfolio positively contribute to the success of an entity in meeting its stated goals or standards. Traditionally, utilities have looked at standards or goals for renewable energy, but this metric could be extended to plans such as Demand Side Management, Energy Efficiency and SMART grid initiatives.

***Improvements in Reliability (value of improving the ability to keep the lights on)***

This metric has three distinct components:

- *Value of delaying or eliminating the need for previously approved reliability projects*: This component monetizes (quantifies) the reliability benefit as the avoided cost (or additional cost) in dollars of delaying, canceling, or accelerating previously approved reliability projects.
- *Value of improved Available Transfer Capabilities (ATCs) of the SPP grid*: This component provides a non-monetized (qualitative) assessment of the added flexibility for the potential redirection of power flows within SPP made possible by ATC increases. The challenge in defining this metric is the development of a meaningful weighting structure of ATC defined for multiple combinations of points of receipt and points of delivery.
- *Value of providing a backstop to a catastrophic event*: This component provides a qualitative assessment of improved grid reliability and its ability to withstand the impact of catastrophic events. This component requires the assessment of catastrophic events and the determination of their probability.

***Enable Efficient Location of New Generation Capacity***

This metric is a quantitative measure of the ability of a transmission project or portfolio to provide for efficient location of new generation capacity. For wind resources, SPP measured distance from the transmission hubs to high wind resource zones. SPP has not yet determined a methodology to use for conventional generation.

***Reduced Losses***

Transmission expansion has an impact on total system losses. This metric serves as a first step in calculating Positive Impact on Capacity required for losses, described below, and gives a quantitative measure for evaluating the relationship between a reduction in losses and the monetary and physical savings from reduced capacity and capital costs.

***Increased Effective Capacity Factor***

This metric is a measure of the value of adding transmission to reduce congestion on curtailed resources. The capacity factor may change due to a reduction in congestion.

### *Ability to Reduce Cost of Capacity*

This metric captures the value from reducing the cost of capacity. This metric is an opportunity to capture value which is not currently being captured. SPP does not currently utilize this metric, and it will require additional tools to calculate which are not currently being used by SPP.

### *Positive Impact on Capacity Required for Losses*

This metric captures a value for the generation capacity that may no longer be required due to a reduction in losses. Due to a lower amount of losses on the system, there is a lower need for generation capacity to support system loses, improving capacity margins.

### *Levelization of Locational Marginal Price (LMP)*

This metric provides a qualitative indicator of the impact an alternate transmission topology could make on regional generation owners' ability to compete on equal grounds. In the absence of congestion and losses on the system, any generator has the potential to serve any load, and there will be a single system price in each hour. A transmission system with no constraints and low losses makes the electricity market more competitive, as it provides an equal opportunity to all generators with similar costs to compete for loads.

In such transmission systems, the market for new entry will also be more competitive. An increase in congestion and losses places generators at certain locations at a disadvantage relative to other similar-cost generators, making the market less competitive. This metric measures the levelization of LMPs for each transmission topology using the standard deviation of LMPs across locations for the SPP footprint. All else being equal, a decrease in the value of this metric indicates an improvement in the competitiveness of the SPP market.

### *Improved Access to Economical Resources Participating in SPP Markets*

This metric provides a qualitative measure of competitiveness across the SPP footprint. It analyzes a generating unit's ability to compete within its own technology type. Capacity-weighted LMPs are calculated for generating plants of different technology types on an hourly basis, and then averaged across 25% of the largest hourly standard deviations.

### *Change in Operating Reserves*

This metric provides a measure for the impact on operating reserves due to transmission expansion. Calculation of this metric requires a capacity expansion model which SPP does not currently license. This metric could provide an opportunity to capture value from reducing operating reserves.

### *Transmission Loading Relief (TLR) Reduction - Enabling Market Solutions*

This metric has been utilized in the past to determine the impact on TLR Reduction for transmission expansion plans; however, with the implementation of the Integrated Marketplace

(SPP's Day Ahead market) in SPP, the need for TLR calls between SPP Balancing Authorities will be eliminated. Congestion will be managed by economic security constrained unit commitment and dispatch.

***Improvements to Import/Export Limits***

This metric quantifies the change in ATC that corresponds to an alternative topology in the Cost-Effective Plan. Three categories of ATC changes are of interest and addressed by this metric:

- *From major generation centers within SPP to key delivery points on the boundary of SPP*. This category relates to export capability improvements.
- *From key external receipt points at the boundary of SPP to load centers within SPP*. This category relates to import capability improvements.
- *From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP*. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.

***Improved Economic Market Dynamics Not Measured in the Security Constrained Economic Dispatch Model***

This metric quantifies the impacts on market dynamics that are not captured in a traditional production cost tool. This metric has not been calculated by SPP; however, it should be evaluated for use in future assessments as there is the potential to calculate value not currently being captured by other metrics.

***Improved Economic Market Dynamics Measured in the Nodal Security Constrained Economic Dispatch Model***

This metric measures the impacts on market dynamics as seen in production cost analysis. However, because this metric requires calculating the generation loading distribution factor for every hour, SPP has not yet been able to calculate this metric. Future assessments should evaluate this metric to capture additional value.

***Reduction in Market Price Volatility***

This metric measures the reduction of market price volatility for transmission expansion projects. This metric requires using a stochastic model which SPP does not currently have the ability to process. Future assessments should reevaluate this metric to determine a calculation method which could be used to capture reductions in market price volatility.

***Reduction of Emission Rates and Values***

If an alternative topology results in a lower fossil fuel burn (or less coal-intensive generation), then $SO_2$, $NO_X$, $CO_2$, and Hg emissions would be lower with the alternative topology in place. APC captured the cost savings associated with reduced $SO_2$, $NO_X$, and $CO_2$ emissions because the allowance prices for these pollutants were inputs to the production cost model simulations.

However, since mercury is not a pollutant subject to an allowance price, changes in coal generation and the corresponding changes in mercury emissions are not currently captured.

This metric addresses that analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in SO2, NOX, and CO2 emissions so that they may be represented as stand-alone values, separate from APC.

***Transmission Corridor Utilization***

Transmission expansion plans that effectively utilize existing right-of-way (ROW) and have topology that largely avoids environmentally sensitive areas are preferable to those that do not, all else being equal.

The metric is comprised of two sub-metrics. The first sub-metric measures the proportion of transmission expansion plan costs that do not effectively utilize existing ROW. The second sub-metric measures the proportion of transmission expansion plan costs that traverse environmentally sensitive areas.

***Ability to Reduce Cycling of Base Load Units***

This metric evaluates the benefit derived from reducing cycling of large base load generating plants. For purposes of this metric, a cycle occurs each time a unit's output crosses or reaches the average output, then recedes below this average minus a tolerance during any start-up to shut-down period. A transmission project that reduces the total number of cycles for a base load unit would reduce maintenance costs and prolong the unit's life span.

If SPP had data on the relationship between the number of cycles and operations and maintenance cost, or had a dollar value associated with excessive versus normal or ideal cycling, this metric could be monetized to determine a value to generators from reduced cycling.

***Generation Resource Diversity***

Transmission topology that results in a more diverse generation capacity expansion plan would add benefit because the power system could respond more flexibly to relative fuel price changes.

This is a semi-quantitative metric based on generation mix (energy basis) from the production cost model simulation. For a given future, this metric is a comparison of the generation mixes (energy basis) from the cost-effective topology and an alternative topology. Both the annual generation mix and the fuel-on-the-margin mix are considered. Of particular interest is whether gas-fired generation approaches or exceeds a specific percentage of the generation mix, because the level and volatility of gas prices is typically relatively high compared to the level and volatility of coal and nuclear fuel prices. Excessive dependence on gas-fired generation, to the detriment of a more balanced dispatch of gas, oil, coal, and nuclear energy, exposes ratepayers to greater fuel price risk.

***Ability to Serve Unexpected New Load***

This metric measures the ability of an alternative transmission topology to serve new load at levels that are different from those considered in APC. The metric tests two types of load changes: an overall incremental load in proportion to load forecast used in the development of each future and load shifts between major load centers.

***Part of overall EHV Overlay Plan***

This metric serves as an indicator to determine how a project fits in with the overall EHV Overlay Plan. If a project keeps appearing across multiple studies, it is a strong candidate for future development. This metric applies value for projects that fit in well with the overall goals of EHV expansion for a region.

## SECTION 3: RECOMMENDED REVIEW METHODOLOGY

### 3.1 RARTF Recommended Principles for the Regional Cost Allocation Review

Based upon research, stakeholder input and extensive discussion, the RARTF recommends that the Regional Cost Allocation Review be conducted utilizing the following principles:

(1) Simplicity – The Regional Cost Allocation Review should be as simple as possible so that the report has a distinct understandability.

(2) Roughly Commensurate – The Regional Cost Allocation Review should use the principle of "roughly commensurate" as the legal framework and a guidepost when evaluating the reasonable and long-term equity of SPP regional transmission upgrades under the Highway/Byway cost allocation methodology.

(3) Use Best Information Available – The Regional Cost Allocation Review should use the most up to date and best available information for the review.

(4) Consistency – The Regional Cost Allocation Review should be consistent.

(5) Transparency – The assumptions, inputs, and data used in the Regional Cost Allocation Review should be transparent to SPP stakeholders.

(6) Stakeholder Input - The assumptions, inputs, and data used in the Regional Cost Allocation Review should be vetted through SPP's open and transparent stakeholder process.

(7) Real Dollars – The Regional Cost Allocation Review Analysis and Report should use dollar values of the year in which the report will be issued.

(8) Consideration Given to Certain Plans – The Regional Allocation Cost Review should give considerations to certain plans that have been approved by the SPP Board of Directors. This includes projects that have been issued an NTC since June 2010 and all projects that have

received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

(9) More Weight Should be Given to Nearer Term Projects than Future Projects – Although the Regional Cost Allocation Review should give consideration to certain plans approved by the SPP Board of Directors, less weight should be given to plans which have been given an ATP as opposed to a NTC.

(10) Equity Over Time – The Regional Cost Allocation Review should adhere to the long term view of the Highway/Byway cost allocation methodology to strive toward regional cost allocation equity over time.

## 3.2 Regional Cost Allocation Review Methodologies

Because the Regional Cost Allocation Review is for projects that will be built under SPP's Highway/Byway cost allocation methodology, the RARTF recommends that certain projects and plans which are approved by the Board of Directors be evaluated. However, due to the less certain nature of the some projects, the RARTF recommends that emphasis of the review be placed on Board of Director approved plans that have in-service dates of ten years or less .

Since both a too conservative approach and a too broad approach to analyzing benefits of transmission projects can be problematic, the RARTF proposes using a single methodology for assessing the benefits and costs of under SPP transmission projects under the Highway/Byway cost allocation methodology. With this methodology, SPP staff would issue two evaluation reports to assess the impacts of the Highway/Byway cost allocation methodology. The two evaluations would include an assessment of:

(1) NTCs: All SPP projects that have been issued an NTC since June 2010;[17] and

(2) NTCs and Projects within 10 years: All SPP projects that have been issued an NTC[18] since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

[17] Attachment J, Section III.D.2 of SPP's OATT, requires that the Regional Allocation Review "shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010." The RARTF views that the report in Section 3.2(1) will comply with the Tariff. However, the RARTF believes that additional analyses need to be considered by SPP stakeholders in light of the fact the Highway/Byway applies to future projects that have yet to receive an NTC. Hence the RARTF recommends additional studies as stated in 3.2(2) so that the focus is not exclusively on the first projects that fall under SPP's Highway/Byway. As FERC noted in the October 20, 2011 Order on Rehearing, "the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP." *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 at P 32 (2011).

[18] Conditional Notices to Construct or CNTCs are considered NTCs and therefore should be included and evaluated as a NTC as contained and provided in this Report.

### 3.3 RARTF Recognition of Weighting Given to Projects without NTCs.

When conducting the Regional Cost Allocation Review described in Section 3.2(2) above, the RARTF recommends that projects with ATPs with an in-service of 10 years or less, but without NTCs, be considered in the Review. However, in considering these projects, the RARTF recommends a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value. The RARTF makes this 0.75 weighting recommendation due to the less certain nature of these projects as well as their costs and benefits.

### 3.4 RARTF Recommended Baseline for the Regional Cost Allocation Review

Because the Regional Cost Allocation Review is for projects that will be built under SPP's Highway/Byway cost allocation methodology, the RARTF recommends that the baseline used to measure the benefits should include all projects which were in-service or received an NTC prior to June 2010. The baseline used in the first Regional Cost Allocation Review should be the same baseline used in all future reviews.

### 3.5 RARTF Recommended Calculation of Benefits to Cost Ratios.

The RARTF recommends using a methodology in which each assessment report uses the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted. Using the aggregate value of dollars instead of the average B/C ratios provides a more comprehensive view of the total benefits to individual zones over the course of multiple studies.

### 3.6 RARTF Recommends Use of a 40-Year Project Evaluation.

To remain consistent with SPP's OATT, the RARTF recommends using a 40-year assessment to evaluate all transmission projects in the Regional Cost Allocation Review. Pursuant to SPP's OATT, the last 20 years of benefits should have a terminal value.

### 3.7 RARTF Recommendation on the Calculation of Costs.

When conducting the Regional Cost Allocation Review the RARTF recommends using the most up to date ATRR for each zone.

### 3.8 RARTF Recommendation on Benefits to be Calculated.

The RARTF recommends that the set of benefit categories listed below in this section be used in the Regional Cost Allocation Review process. It is further recommended that before the Regional Cost Allocation Review is conducted, the development of specific metrics that quantify the benefits in dollars using the procedures defined by the MOPC through the work of the Economic Studies Working Group (ESWG) be completed. For metrics without dollar amount but in other terms (MW, MWh, Tons, etc.), the ESWG should consider recommending a range of values that can be used to monetize those metrics without hard dollar values. As part of the benefit evaluation, the most conservative or lowest number in any range provided by the ESWG will be used in the Regional Cost Allocation Review. For those metrics that the ESWG does not endorse monetizing, the ESWG will not provide a monetized value for use in the Regional Cost Allocation Review process. In defining these benefits, the ESWG and the MOPC should also develop a method to distribute these benefits by SPP zones. For those benefits that cannot be distributed to all zones but shared by fewer than all zones, if the benefited zones agree to an alternative method for allocating the benefits, then the agreed upon method will be used.

When conducting the Regional Cost Allocation Review, the RARTF recommends using the list of benefits in this section to assess the benefit to cost ratio. Additionally, the Regional Cost Allocation Review should consider the use of any additional benefits that may be defined and quantified in dollar values or can be converted into dollar values by the EWSG and approved by the MOPC.

The list of benefits the RARTF recommends be used in the Regional Cost Allocation Review are:

- **APC Benefits** – APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that are directly related to energy production by generating resources in SPP. APC is calculated by adding a zones production cost to the zones purchases and subtracting out their sales.

- **Positive Impact on Capacity Required for Losses**– This captures a value for the generation capacity that may no longer be required due to a reduction in losses.

- **Improvements in Reliability** – There are five parts to improvements in reliability:

    - Benefits of avoided projects which are no longer needed due to additional transmission development.

    - From major generation centers within SPP to key delivery points on the boundary of SPP. This category relates to export capability improvements.

    - From key external receipt points at the boundary of SPP to load centers within SPP. This category relates to import capability improvements.

    - From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.

    - Reliability projects provide more value than just reliability; reliability projects can provide measurable economic benefit. The ESWG will continue to develop this portion of the reliability metric in early 2012.

- **Remedy Benefits** – The value of previously approved remedies will be captured as a benefit during all following Regional Allocation Reviews.[19]

- **Reduction of Emission Rates and Values** – This metric addresses the analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in $SO_2$, $NO_X$, and $CO_2$ emissions so they may be represented as stand-alone values, separate from APC.

- **Reduced Operating Reserves Benefits** – As additional transmission is put in service it may reduce the amount of operating reserves needed in the SPP footprint. This metric captures the value of reduction in reserves.

- **Improvements to Import/Export Limits** – This metric quantifies the change in ATC that corresponds to an alternative topology.

- **Public Policy Benefits** – This metric captures the value of meeting the requirements of public policy. This metric is still under evaluation by the ESWG and will continue to be developed throughout early 2012.[20]

### 3.9 RARTF Recommendation on Assumptions to be Used.

The RARTF recommends that the assumptions used in the Regional Cost Allocation Review should be vetted through SPP's open and transparent stakeholder process.

## SECTION 4: REPORT THRESHOLDS

### 4.1 RARTF Recommends a Remedy Threshold

Pursuant to the RARTF Charter, the RARTF recommends that a threshold be established to determine when it is warranted for SPP staff to study possible remedies to address an imbalance based upon the results of a Regional Cost Allocation Review. This threshold defines when SPP staff should study a zonal mitigation. If a zone is determined to be below this threshold, mitigation may be necessary to create equity.

The RARTF recommends that a threshold be set at a 0.8 benefit to cost ratio for projects that are a part of the assessment report stated in Section 3.2(2) above.[21] Section 3.2(2) calls for a report on "all SPP projects that have been issued an NTC since June 2010 and all projects that have

[19] This benefit would only be applicable in subsequent reviews for any mitigation that was implemented as a result of a previous Regional Cost Allocation Review.
[20] The RARTF notes that although it is SPP's current practice is to plan for public policy objectives, under FERC Order 1000 SPP is required to plan for public policy objectives. Consequently, the evaluation and measurement of these benefits are consistent with the requirement to plan for them.
[21] The RARTF notes that the 0.8 B/C ratio recommended in this report based upon the ESWG and SPP Stakeholder approving a method to measure the benefits listed in Section 3.8. Additionally, the RARTF notes that the 0.8 B/C may not be appropriate or practical if a Review produces a B/C ratio for all projects lower than anticipated by the RARTF.

received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report."

The RARTF finds that during the first Regional Cost Allocation Review, few, if any, projects will actually be in service;[22] and that consideration should be given to all Board of Directors approved projects contained in plans that have an in-service date of ten years or less from the year of the report. The importance of considering future plans is highlighted by FERC's Order on Rehearing in Docket No. ER10-1069-001 in which FERC noted that the Highway/Byway cost allocation methodology will be applied to projects other than the Priority Projects.[23]

### 4.2 RARTF Recommendation for Zones Above Threshold but Below 1.0 B/C.

Pursuant to the RARTF Charter, the RARTF recommends that a threshold be established to determine when it is warranted that SPP staff study possible remedies as stated in Section 4.1.

Additionally, the RARTF recommends that any Regional Cost Allocation Review, which shows that a zone is above the 0.8 threshold in Section 4.1, but below a 1.0 benefit to cost ratio, should be used and considered as a part of SPP's transmission planning process in the future.

## SECTION 5: POTENTIAL REMEDIES TO BE STUDIED

### 5.1 RARTF Recommended Zonal Remedies

If the results for a zone following a Regional Cost Allocation Review are below the threshold in Section 4.1, the RARTF recommends that the SPP staff should evaluate, and recommend possible mitigation remedies for the zone. In Figure 5, there is a list of mitigation remedies that the RARTF recommends SPP staff consider for study and to be made part of the report. The purpose of the evaluations is to determine potential remedies that bring the zone above the threshold.

The potential list of remedies, listed in order of preference, that SPP staff could evaluate include, but are not limited to:

[22] The Tulsa Reactor from Priority Projects is estimated to be the only project in service by June 2012.
[23] As FERC noted in the October 20, 2011 Order on Rehearing, "the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP." *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

| Remedy | Entity with Authority/Duty to Implement |
|---|---|
| **(1) Acceleration of planned upgrades;** | **SPP BOD** |
| **(2) Issuance of NTCs for selected new upgrades;** | **SPP BOD** |
| **(3) Apply Highway funding to one or more Byway Projects;** | **RSC, SPP BOD & FERC** |
| **(4) Apply Highway funding to one or more Seams Projects;** | **RSC, SPP BOD & FERC** |
| **(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;** | **RSC, SPP BOD & FERC** |
| **(6) Exemptions from cost associated with the next set of projects;** | **RSC, SPP BOD & FERC** |
| **(7) Change Cost Allocation Percentages.** | **RSC, SPP BOD & FERC** |

**Figure 5. Potential remedies.**

## SECTION 6: TIMELINE

### 6.1 Proposed Regional Cost Allocation Review Timeline

The RARTF recommends the Action Plan, identified in Figure 6 below, be followed to conduct the Regional Cost Allocation Review. The ESWG's determination of the metric and values of all benefits to be studied as stated in Sections 3.9 and 7.1 is critical to the timeline.

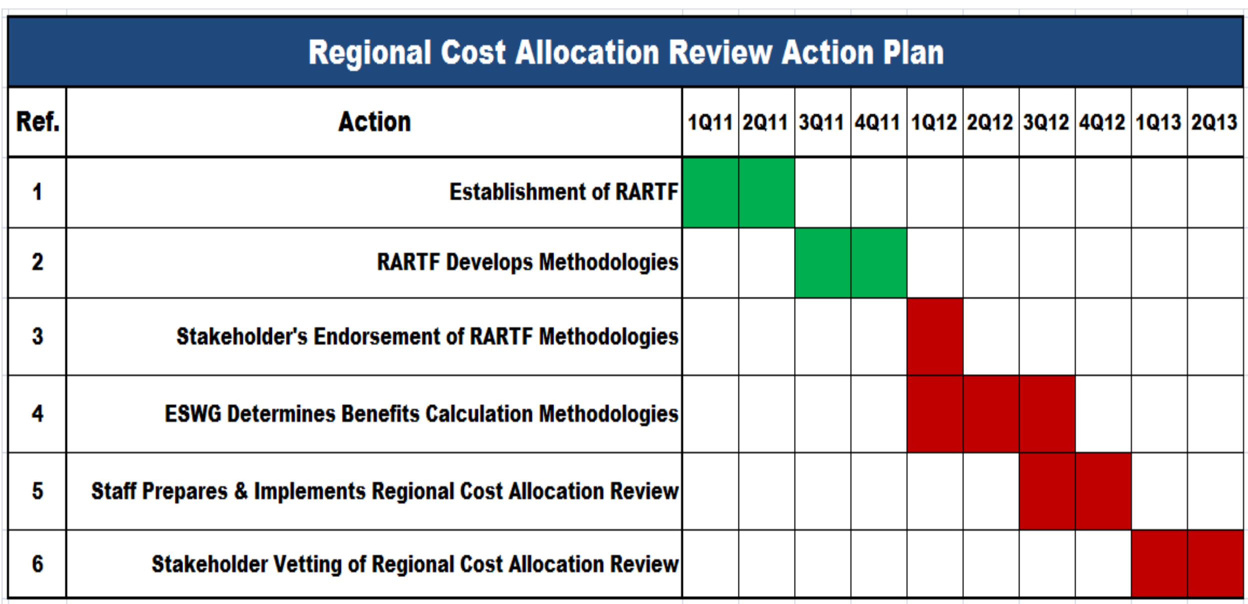


**Figure 6. RARTF Proposed Action Plan**

## SECTION 7: ADDITIONAL RECOMMENDATIONS/CONSIDERATIONS

### 7.1 Recommendations Going Forward

The RARTF makes four additional recommendations:

First, the Regional Cost Allocation Review should not be conducted until the ESWG completes its work in defining how the benefits described in Section 3.8 are calculated. As stated in Figure 6, the RARTF recommends that the ESWG define the benefits by the end of the third quarter of 2012. This will allow for Regional Cost Allocation Review to be conducted pursuant the methods recommended by the RARTF.

Second, the RARTF recommends that the SPP Board of Directors approve the RARTF Report, and SPP stakeholders develop and revise Business Practices, the ITP Manual, and, as necessary the OATT, to effectively implement the Regional Cost Allocation Review process and potential remediation actions as contained in this Report. Once the Regional Cost Allocation Review process and potential remedies are a part of SPP's Business Practices or ITP Manual any subsequent changes to the procedures detailing this process must be reviewed by the MOPC and RSC and approved by the Board. The RARTF finds that many of the issues addressed in the RARTF Report may serve as valuable and useful additions to SPP's Business Practices, the ITP Manual, as well as the language of the OTT, for existing transmission planning processes and future Regional Cost Allocation Reviews.

Third, as required by SPP's OATT, the Regional Cost Allocation Review must be conducted at least every three years. Because this three year requirement can be synchronized with SPP's three year ITP planning cycle, the RARTF recommends that that the Regional Cost Allocation Review be conducted simultaneous with SPP's three-year planning cycle. This coordination can assist SPP and its stakeholders in evaluating past and conducting future three-year planning cycles.

Fourth, the RARTF found the process of developing the recommended methodology under which the Regional Cost Allocation Review will be performed to be a very informative and collaborative process. As a result, the RARTF recommends that the task force be reconvened before subsequent Regional Cost Allocation Reviews are performed. This will enable the SPP stakeholders to review lessons learned from prior Regional Cost Allocation Reviews and to suggest improvements to the methodology recommended in this report.