Southwest Power Pool

Cost Benefit Study for Future Market Design

FINAL Report

April 7, 2009

Ventyx Authors

Barbara Coley

Isaac Johnson

Erdal Kara

Alexandra Miller

Ronald Moe

Gary Moland

Jessica Opraseuth

Duane Sheffield

Keith Smith

CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

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.

Ventyx
Performance Proven

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

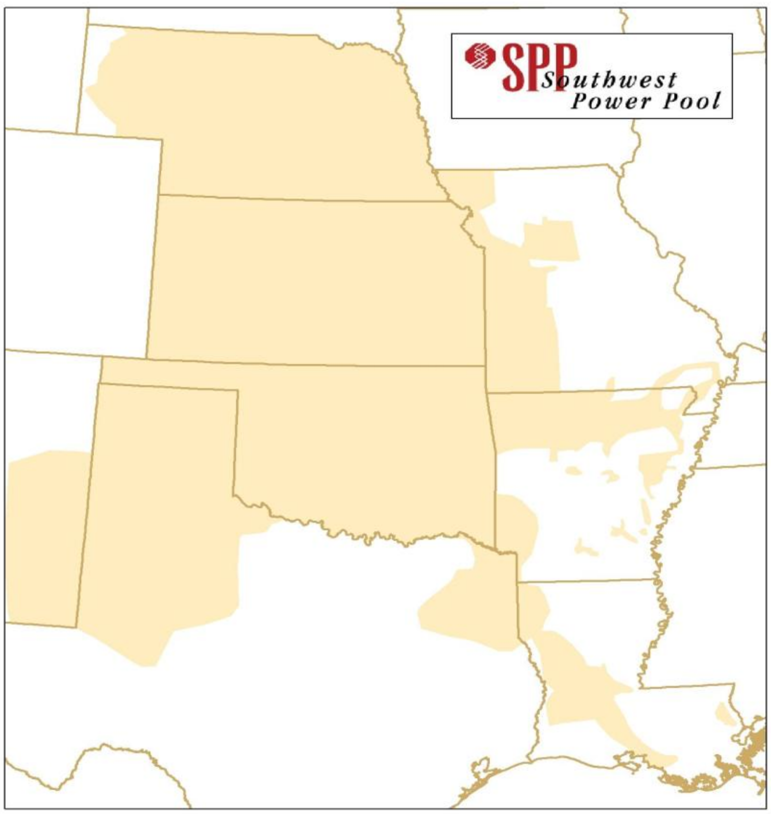
A key aspect of the benchmark effort was the development of an "economic threshold" representing a barrier to economic interchange between Balancing Areas in SPP. These economic thresholds represent the minimum price differential between two areas that must occur before interchange between the pools 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

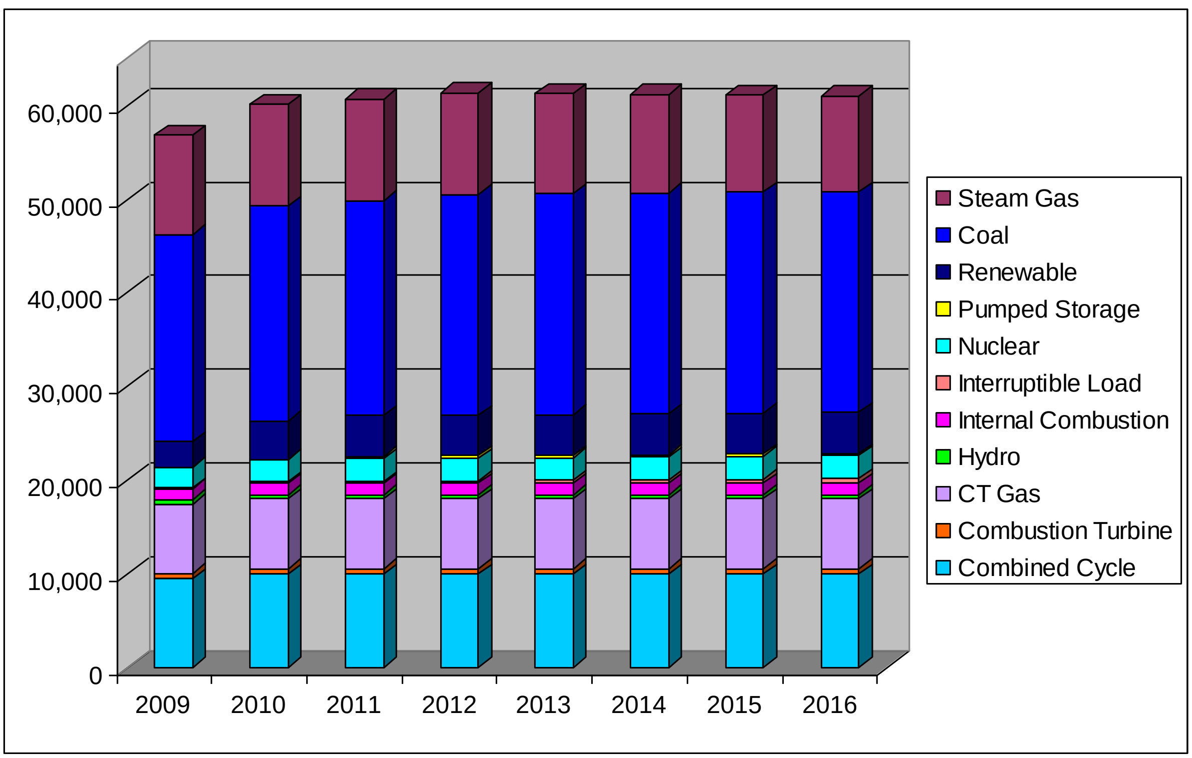
- 500 megawatt hours of annual wheeling for others (deliveries plus losses)

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)

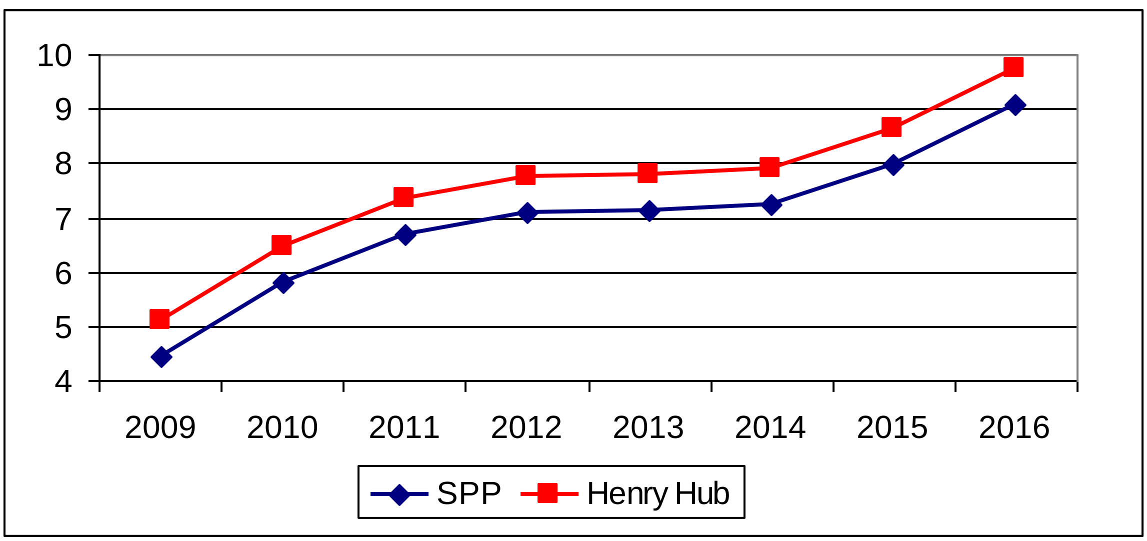
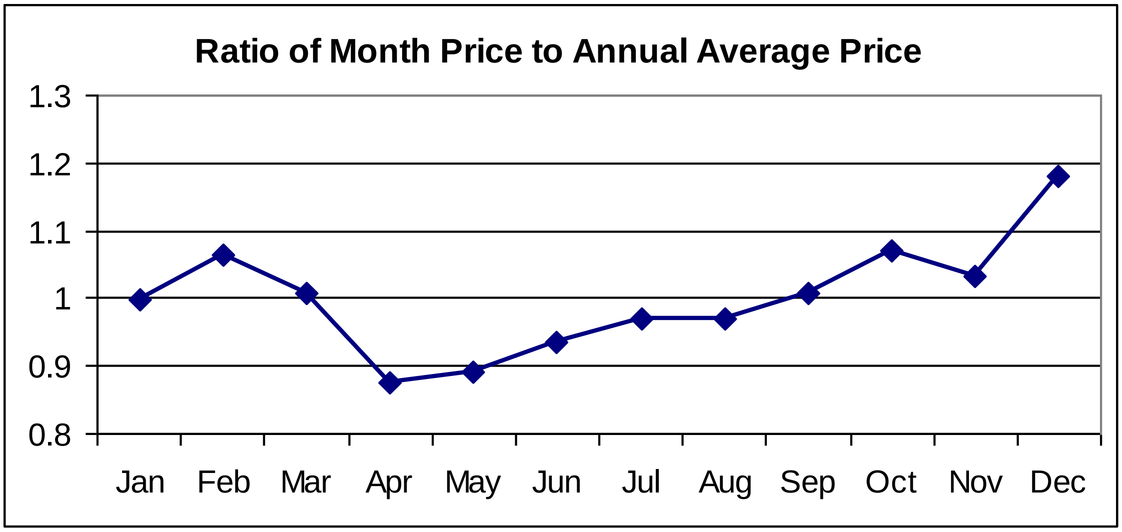


Figure 3-3 SPP Natural Gas Prices - Monthly Price Pattern



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		
% 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 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.		
Estimated cost of equity	11.50%	
x financing factor	20%	
Weighted average cost of equity		2.30%
Estimated cost of debt	7.50%	
Corporate tax rate	0%	
x financing factor	80%	
Weighted average cost of debt		6.00%
Total current rate of return		8.30%
Rounded		**8.30%**

Assumptions		
% 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 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.		
Estimated cost of equity	11.50%	
x financing factor	20%	
Weighted average cost of equity		2.30%
Estimated cost of debt	7.50%	
Effective corporate tax rate	40%	
x financing factor	80%	
Weighted average cost of debt		3.60%
Total current rate of return		5.90%
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 $)

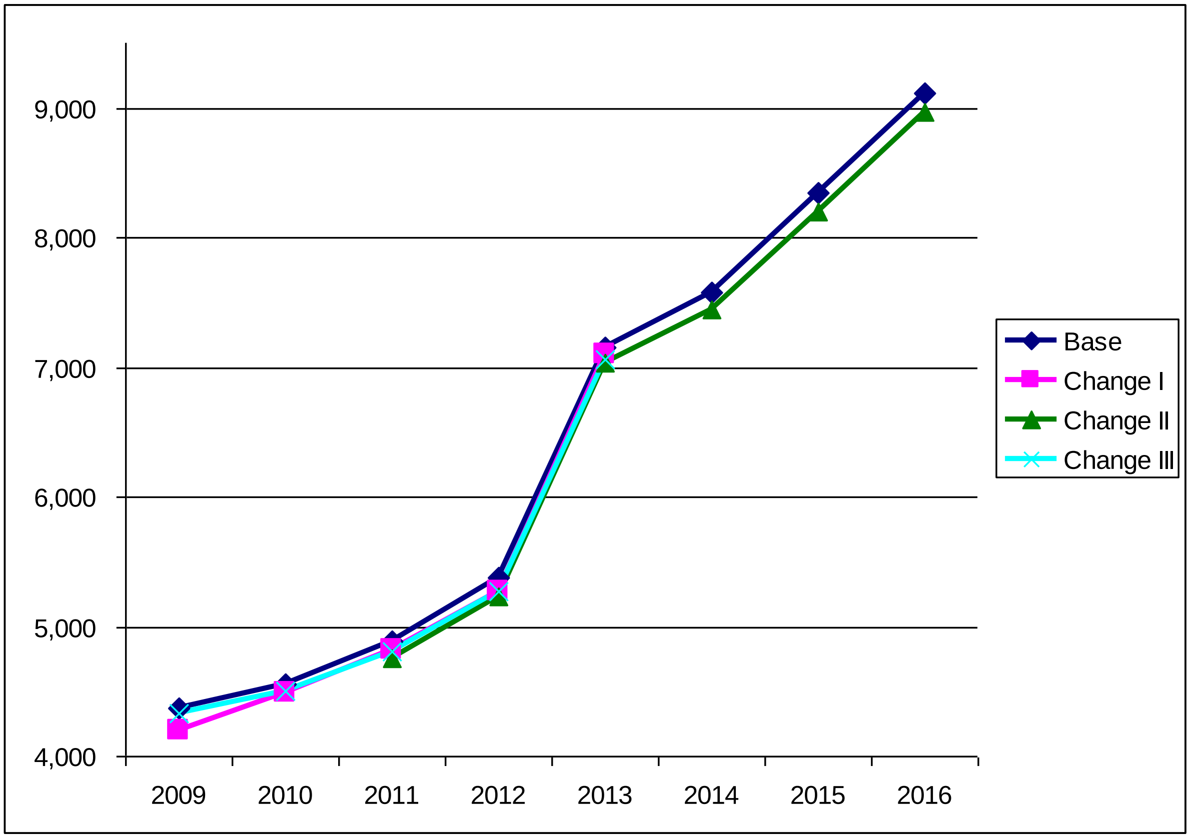


Table 4-1 summarizes the estimated annual SPP-level gross benefits for each of Change Cases I, IIA, IIB, IIC, and III[5]. During the 2011 – 2016 period (the period for which gross benefits for all three change cases were calculated), estimated gross benefits in Change Case I average approximately $85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

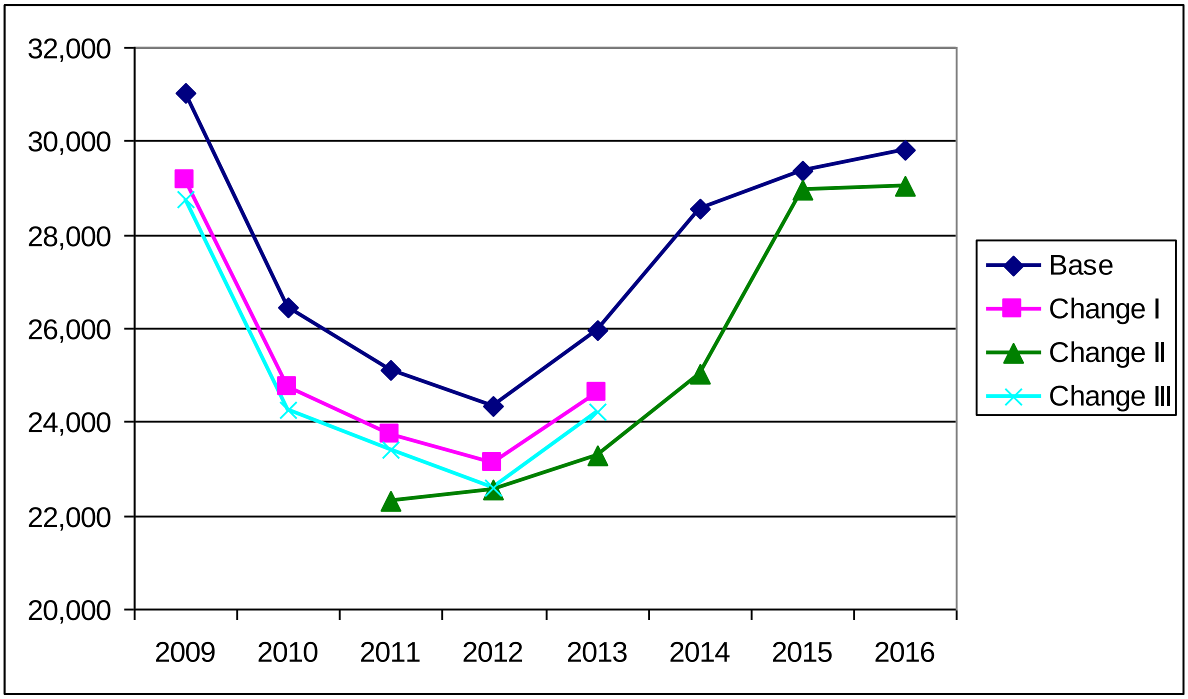


Figure 4-3 Combustion Turbine Annual Generation, By Case (GWh)

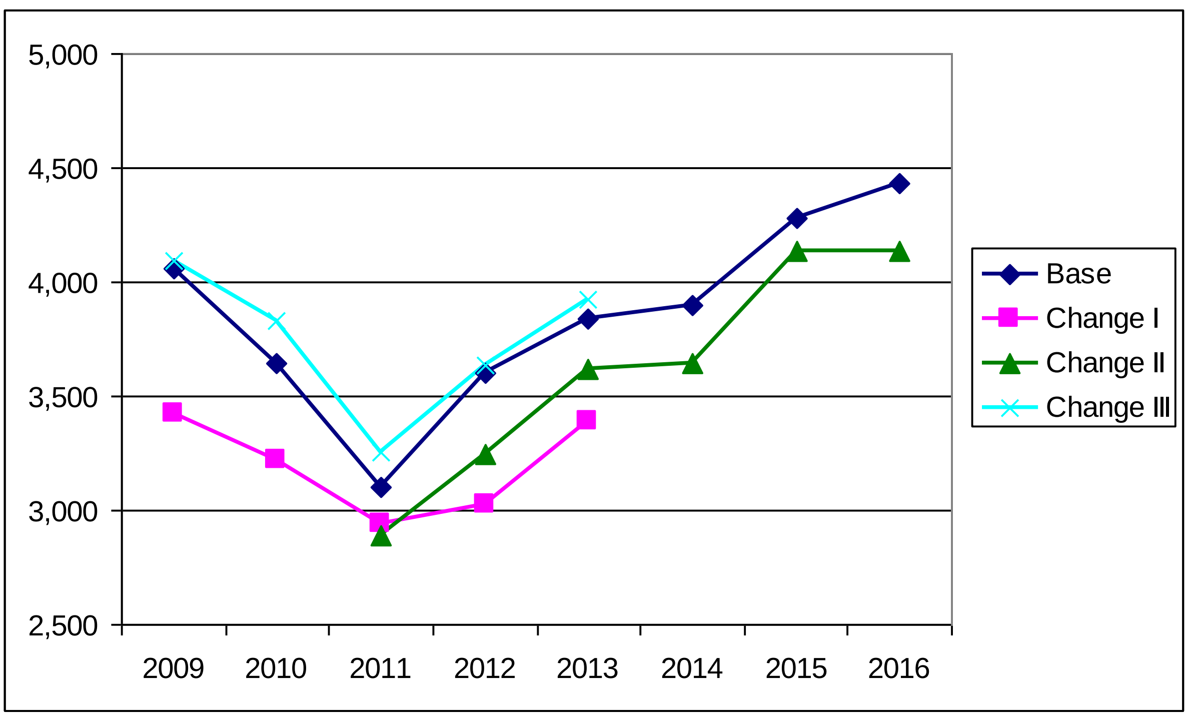


Figure 4-4 Steam Coal Annual Generation, By Case (GWh)

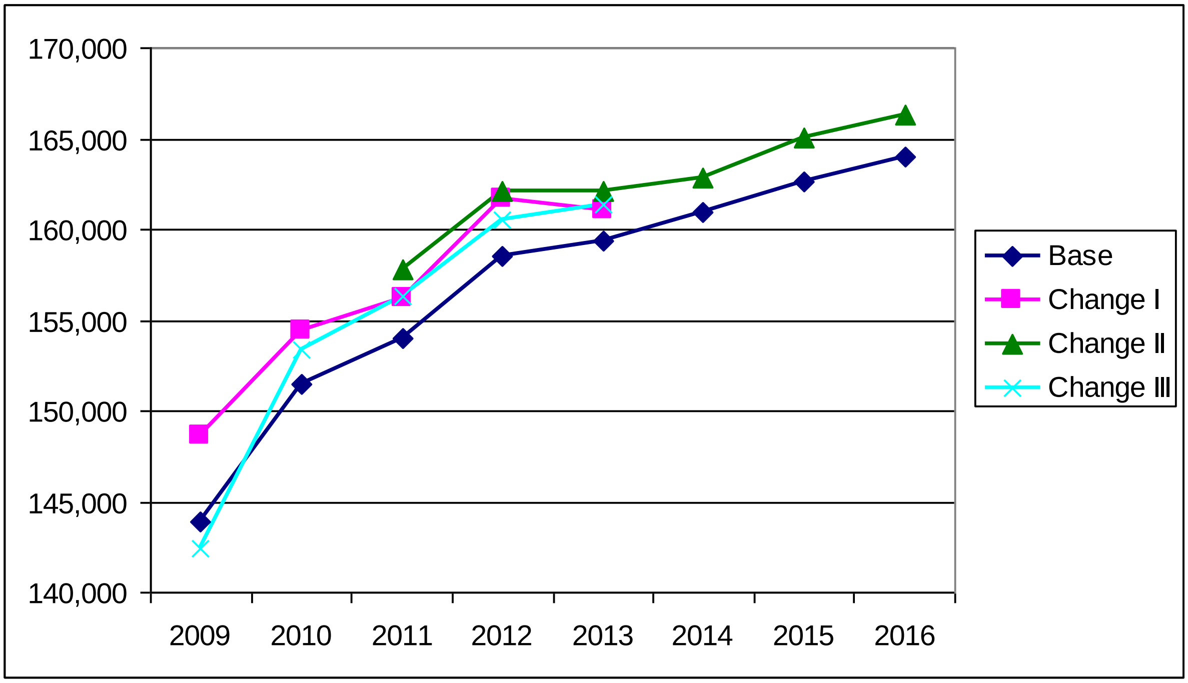


Figure 4-5 Steam Gas Generation, By Case (GWh)

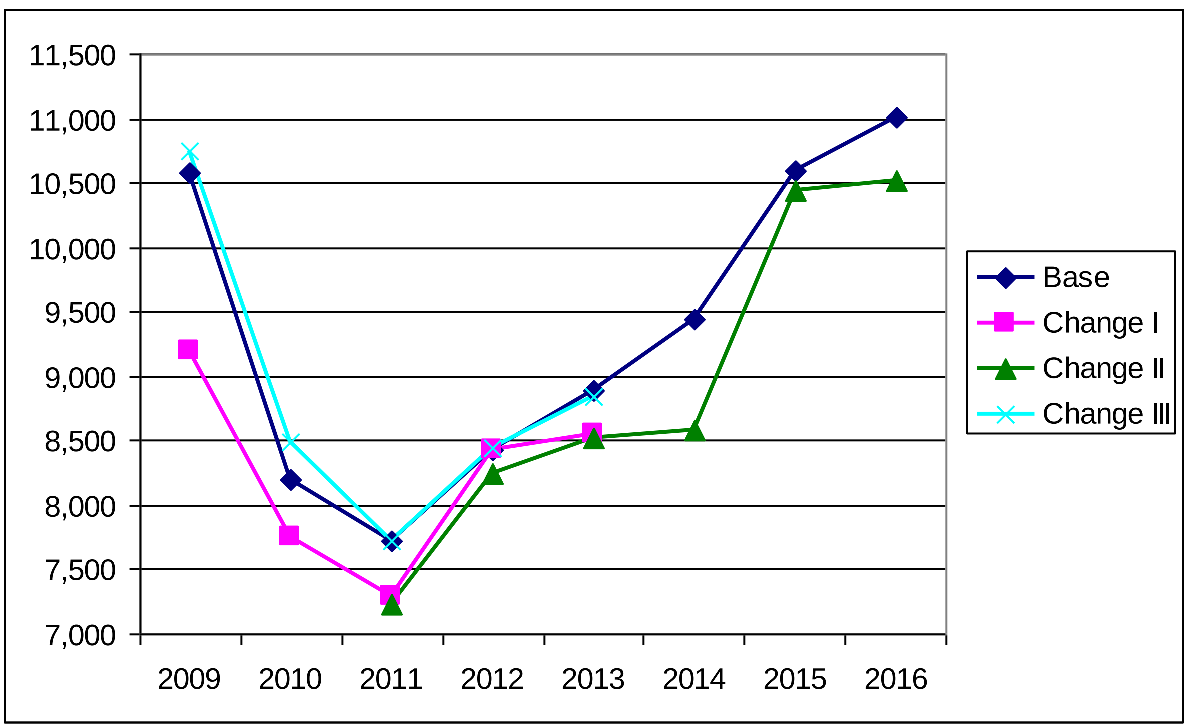
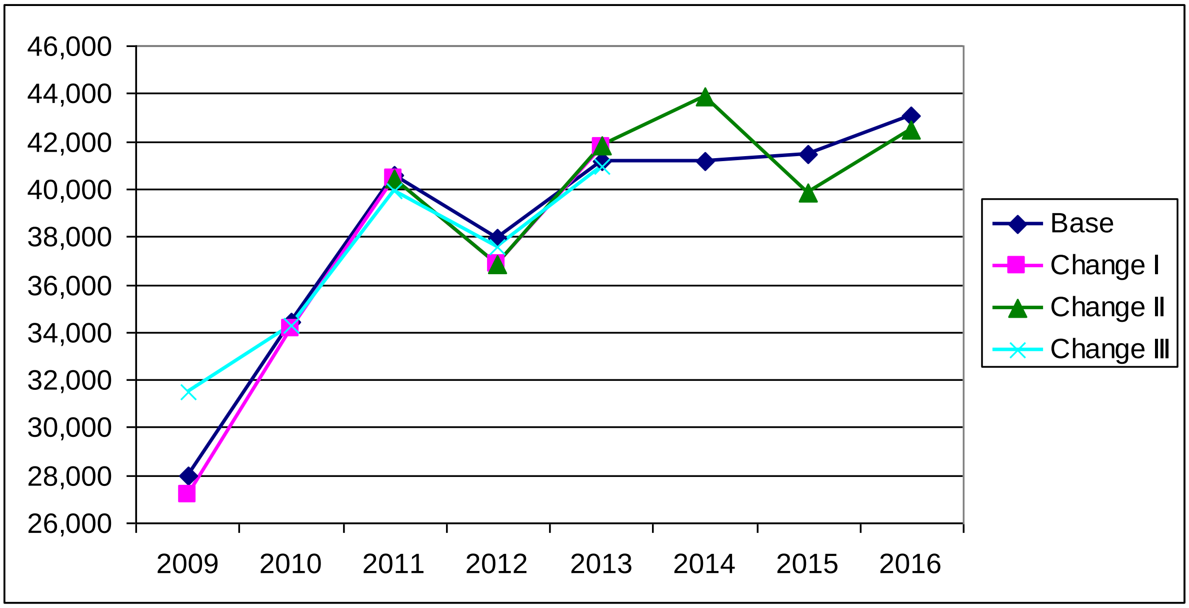


Figure 4-6 SPP Net Remaining Supply by Case (GWh)



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 $)

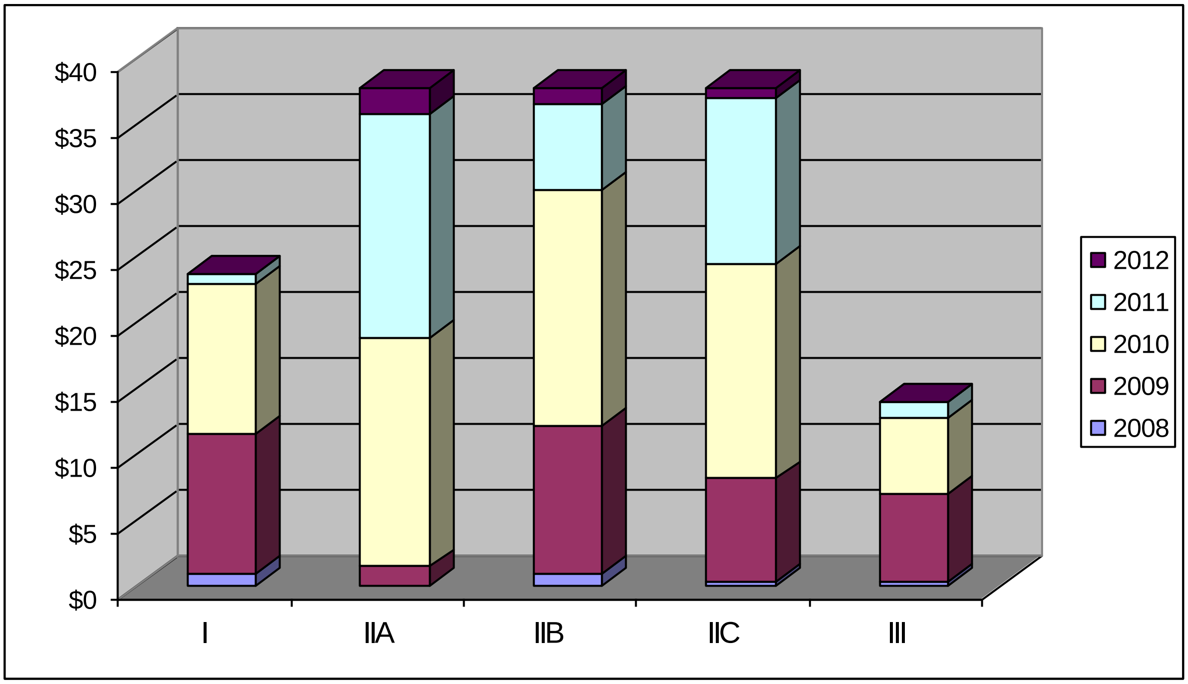
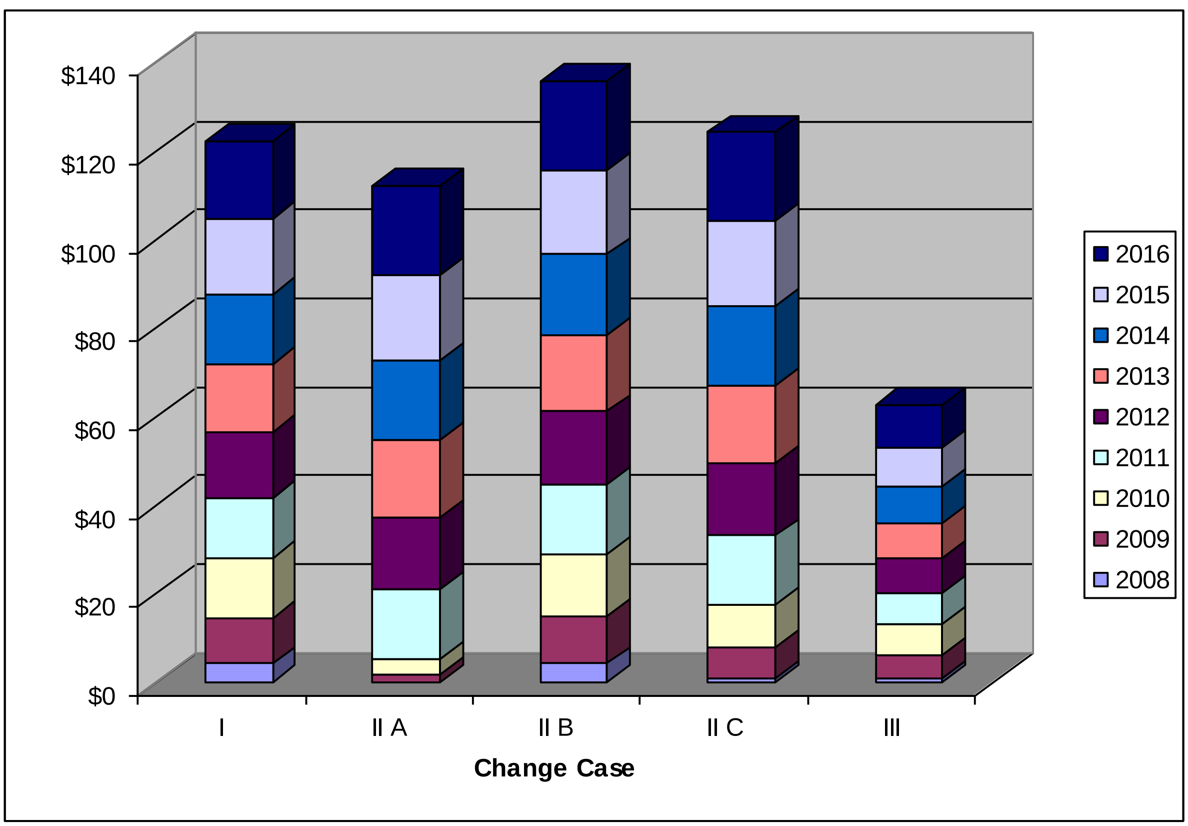


Figure 4-8 SPP Implementation Annual Operating Costs (Million $)



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**

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.

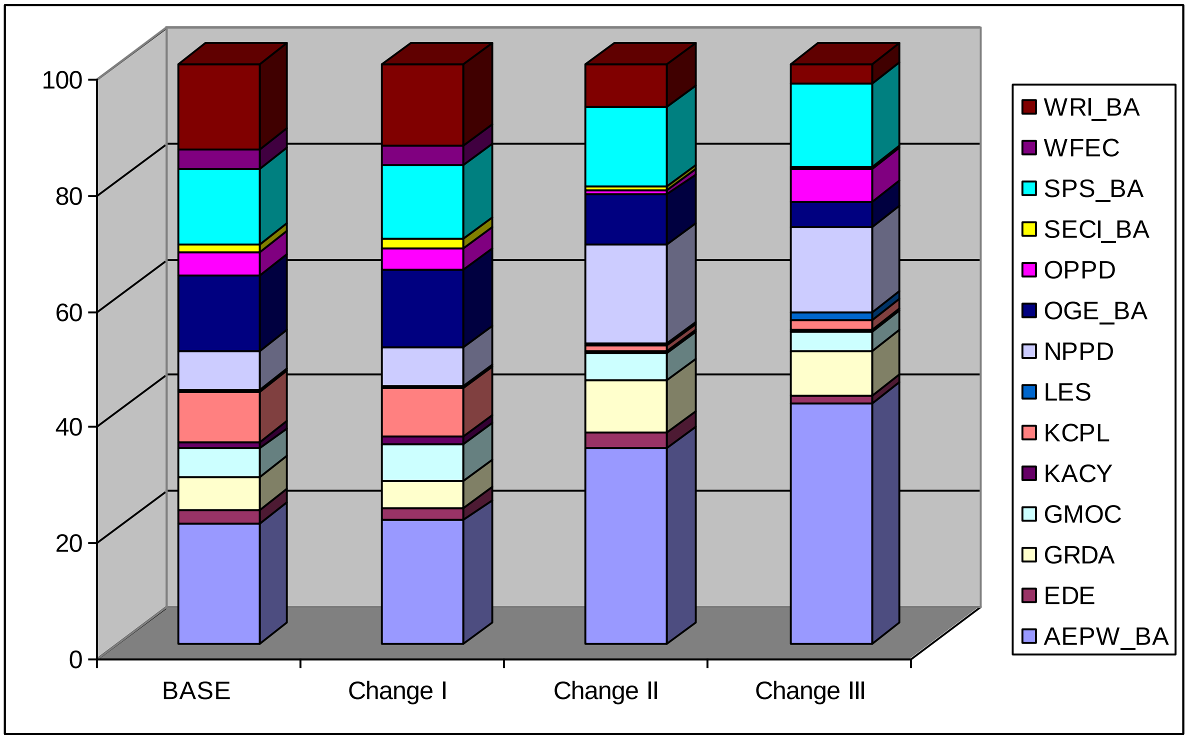
Table 4-18 Average 2012 SPP Market On-Peak Load Hub Prices ($/MWh)

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