



**Southwest Power Pool
REGIONAL STATE COMMITTEE
MEETING**

April 25, 2005

• M I N U T E S •

Administrative Items

Members in attendance or represented by proxy were:

Denise Bode, Chairman Oklahoma Corporation Commission (OCC)
Brian Moline, Kansas Corporation Commission (KCC)
Julie Parsley, Texas Public Utility Commission (TPUC)
Steve Gaw, Missouri Public Service Commission (MPSC) via phone
Sandy Hochstetter, Arkansas Public Service Commission (APSC)

Others in attendance:

Pat Wood, FERC
Tony Ingram, FERC
Mike McLaughlin, FERC
John Rogers, FERC
Richard House, APSC
Sam Loudenslager, APSC
Mary Ann Cochran, APSC
Tom DeBaun, KCC
Mike Peters, KCC
Mike Proctor, MPSC
James Watkins, MPSC
Ryan Kind, Office of Public Counsel
Pat Davis, OCC
Joyce Davidson, OCC
David Fleischaker, Secretary of Energy
Bridget Headrick, TPUC
Barbara Pennington, TPUC
Adrienne Brandt, TPUC
Erin Gutierrez, TPUC
Bruce Rew, Southwest Power Pool (SPP)
Carl Monroe, SPP
Stacy Duckett, SPP
Richard Dillon, SPP
John Wine, KCC Chairman
David Linten, SPP
Lamona Lawrence, SPP
Les Dillahunty, SPP
Harry Skilton, SPP Director
Jim Eckelberger, SPP Director

Scott Moore, SPP
Nick Brown, SPP
Terri Gallup, AEP
Richard Ross, AEP
Michael Deselle, AEP
Raj Rana, AEP
Calvin Crowder, AEP
Steve Owens, Entergy
Mike Wise, Golden Spread
Walter Wolf, Stone Pigman, Walther, Wittman, LLC
Sha Hossain, West Star
Doug Henry, West Star
Dave Cristiano, City Utilities of Springfield
Jim Stanton, Calpine
Robin Kittel, Xcel
Ralph Luciani,
Carl Huslig, Aquila
Dottie Stockdale,
Ms. Fisher, EEI
Craig Roach, Boston Pacific
Rob Jansen, Boston Pacific
Barry Warren, Empire District Company
Dave Cruthruds, Cruthruds Report
Linda Clarke, Power Partners Consulting
Rick Walker, Wind Coalition
Harry Dawson, OMPA
Beth Martin, Redbud Energy
Christine Ryan, Texas, Arkansas Co, op
Bob Riser, Kansas Electric Power
Mike Wise, Electric Co-op
John Gaines, Oklahoma Gas & Electric
Ron Gary, Lafayette Utility System
Walt Yeager, Synergy
David Gonzales, Gamen Energy
Stephen Wiley, Gamen Energy
Ellen Wolf, Charles River Assoc.
Alex Rudekvich, Charles River Assoc.

RSC President Denise Bode called the meeting to order at 1:00 pm CDT. A quorum was declared.

The April 7, 2005 minutes were approved as presented.

UPDATES:

There were no updates on the financial report or other officer reports.

FERC:

Mr. Ingram presented a brief update on FERC activities. He stated that the order on the cost allocation plan had been issued. He thanked the Cost Allocation Work Group (CAWG) for their efforts in preparing a very good plan. The Commission also issued a Notice of Proposed Rulemaking on wind power generator imbalance protocols. A technical conference was held at FERC last Friday that focused on incentives for transmission infrastructure and how to move forward getting transmission built.

SPP:

Mr. Brown reported that the NERC readiness audit was done last week and passed with flying colors. There were many examples of excellence noted on the audit. There were minor variances however; the overall audit was very good. Published findings will be ready in 60 days. A more detailed report will be provided at the SPP Board Meeting tomorrow, April 26, 2005.

Charles River Associates Cost Benefit Study:

Steve Gaw exited the call for the portion of the discussion concerning Section 7, the Aquila Sensitivity Cases, due to a pending case with a utility included in the study.

Charles River Associates (CRA) presented the SPP, RSC Cost Benefit Study (attached). The Cost, Benefit Study can be found on the SPP website at http://www.spp.org/publications/cba_final_04-23-2005.pfd in its entirety. The group discussed the findings in the Cost Benefit Study and the Mr. Loudenslager thanked Ellen Wolf, Alex Rudkevich, Steve Henderson and Heather Hawson with CRA for an excellent job in preparing the report and presenting the findings to the RSC.

President Bode asked what the next steps would be. The committee members responded that the report would need to be reviewed in detail but as it is written, it can be used for any filing. Mr. Loudenslager commended the Cost Benefit Task Force (CBTF) for providing support and necessary information to CRA that was used in preparation for the report. President Bode commented that this was a big milestone towards the great benefits of working together as a region and with industry.

Tariff Filing:

Mr. Proctor stated that an order was issued on April 22, 2005 approving the tariff provisions. There was one minor change; the reversal of the 180K per megawatt limit on DNR requests or DNR upgrades. FERC also removed the section concerning transmission owners having first right of refusal. Modifications will need to be assessed every two years. CAWG will continue to meet to look at transmission rights and economic upgrades. At this time there is not a timeline for recommendations on these issues. FERC plans to issue notice on this by early May. Mr. Brown stated that the Strategic Planning Committee was elated with the Order and the accomplishments of the CAWG. Chair Hochstetter noted that paragraph 79 language regarding third party ownership needs to be removed where it is not consistent with state statute.

The CAWG will continue to meet to look at transmission rates that go with economic upgrades. Mr. Proctor indicated that FERC is planning to issue a notice of inquiry related to this issue.

Transmission Planning:

Mr. Monroe reported that the Markets Operation and Policy Committee (MOPC) approved a transmission expansion plan that they will be presenting to the Board that shows how to meet the reliability needs of the SPP region through 2010 with specific projects outlined and associated costs. The second phase is the economic plan. The MOPC has suggestions from stakeholders and transmission owners that could benefit the region. A transmission summit has been scheduled for June 1st and a Kansas Panhandle workshop on June 2nd to review the economic analysis. The TAWG is developing criteria to review all the plans for expansion. It is expected that by the October Board meeting the full plan will be put together and presented.

Energy Imbalance Market:

Mr. Ross, chair Market Work Group (MWG), presented his report on the Energy Imbalance Market. Mr. Ross noted that the Operations and Reliability Working Group (ORWG) raised significant questions regarding dispatch cycles and those questions resulted in a delay in market implementation and trials. At this time there is not a timeline for implementation, however, the target is spring of 2006. President Bode expressed urgency on resolving the cycle issues and to determine the new timeline for market implementation and trials.

ICT Development Process:

Mr. Brown reported on the Entergy, ICT development process. FERC accepted Entergy's ITC proposal. Entergy is submitting a compliance filing related to that order today. Continued meetings and discussions are scheduled over the next several weeks. The response to the FERC order is that we agree with the Commission that this is a step in the right direction. Mr. Owens indicated that the discussions were going well and progress is being made.

RSC Associate Member Reimbursement:

Secretary Parsley reviewed the Travel and Reimbursement Policy. Her interpretation is that members, who are the Commissioners or associate members, must submit their travel expenses according to the Policy guidelines. If a designated staff member is submitting a reimbursement, then their Commissioner needs to approve the reimbursement. The form has two places to sign, one for the person requesting reimbursement and one for a Commissioner. What the policy is lacking is a reference to an associate members' authority to sign the reimbursement form. Secretary Parsley will make a change to the policy to reflect that reference and bring it to the next RSC meeting for approval. **Secretary Parsley made a motion that the policy be interpreted as Commissioners or Associate Members may approve and sign the reimbursement form for designated staff members' expenses and that a revised policy will be brought before the next RSC for approval. Vice President Hochstetter seconded the motion. The motion carried.**

Scheduling of Meetings:

The SPP/RSC retreat is scheduled for May 11th through 13th. There will be a working dinner the evening of May 11th for the RSC. The next regular RSC meeting will be July 27 immediately following NARUC, which is scheduled for July 25 and 26 in Austin. President Bode and Secretary Parsley will work out the logistics of the meeting. President Bode will work with the staff at NARUC

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to make sure they make all the arrangements for the RSC meeting. The two meetings will be posted on the SPP web site.

There will also be a brief meeting at the conclusion of the MARC meeting June 22 in Little Rock, Ar.

President Bode extended a special thank you to Pat Wood for his exemplary service as Chair on the FERC Commission.

There being no further business, a motion was made and seconded that the meeting be adjourned.

Respectfully submitted,

Julie Parsley, Secretary

AGENDA

REGULAR MEETING

**Monday, April 25, 2005
(1:00 pm – 5:00 pm CDT)
Crowne Plaza Austin Hotel
500 North IH 35
Austin, Texas 78701
512-457-7932**

- 1. CALL TO ORDER**
- 2. PRELIMINARY MATTERS**
 - a. Declaration of a Quorum
 - b. Adoption of February 15, 2005 Minutes
- 3. UPDATES**
 - a. RSC Financial Report
 - b. Other RSC Officer Reports
 - c. FERC
 - d. SPP
- 4. BUSINESS MEETING**
 - a. Final Report from Charles River Associates on SPP RTO Cost-Benefit Study; any follow-up items or action steps
 - b. Status Report on SPP Transmission Expansion Cost Allocation Tariff Filing at FERC; any follow-up items needed
 - c. Update on next phase of SPP Transmission Planning process; any RSC discussion or action steps required
 - d. Update and Discussion regarding development and implementation of SPP's Energy Imbalance Market
 - e. Status Report regarding SPP's discussions with Entergy regarding the ICT development process

f. RSC Associate Member approval for reimbursement process

g. Other Issues

5. SCHEDULING OF UPCOMING SPECIAL MEETINGS OR EVENTS

Discussion of SPP RSC Retreat, and Joint RSC/SPP Meetings in May

6. SCHEDULING OF NEXT REGULAR MEETING

7. ADJOURN

Notice of Meeting of the Southwest Power Pool Regional State Committee

The Southwest Power Pool (SPP) Regional State Committee (RSC) will hold a public meeting at 1:00 pm CDT on April 25, 2005. The business meeting will involve discussion and possible action on issues related to the cost-benefit study proposed for the SPP Regional Transmission Organization, cost allocation for new transmission facilities, and the office of the treasurer. Members who are not able to attend in person should submit a proxy in accordance with the Bylaws.

Persons planning to attend the meeting by teleconference should register online at least one day prior to the meeting at <http://www.spp.org> in order to obtain the telephone number for conference bridge access. The telephone number will be provided at close of business the day before the meeting.

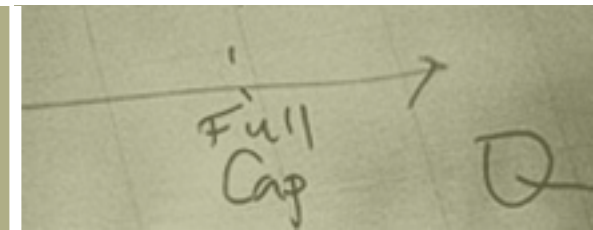


CHARLES RIVER ASSOCIATES

Regional State Committee SPP Cost-Benefit Analysis Report Overview

April 25, 2005

**Ellen Wolfe
Ralph Luciani
Alex Rudkevich**



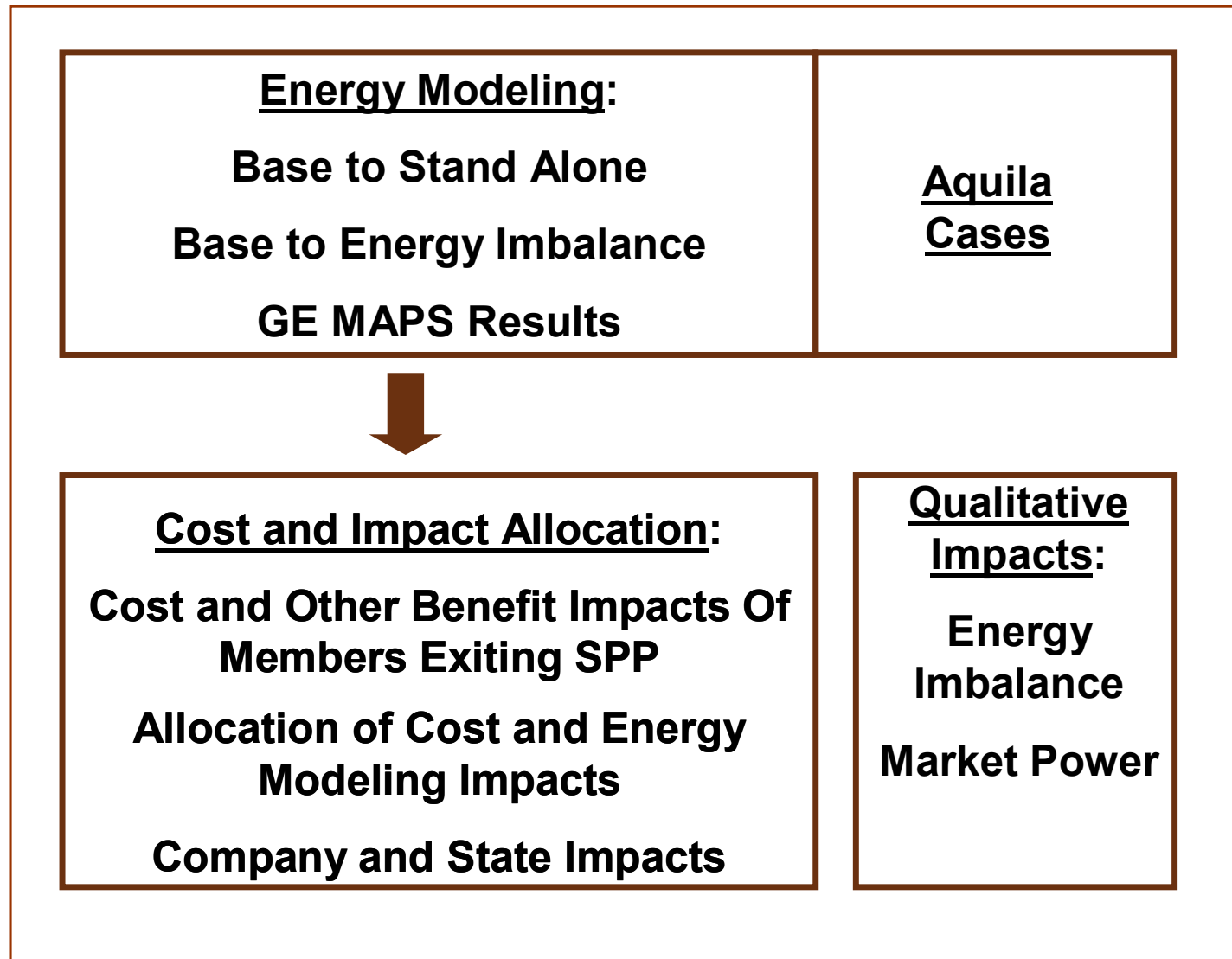
Outline

- Background of Cost-Benefit Analysis
- Study Structure
- Wholesale Energy Modeling: Methodology and Results
- Cost Impact and Allocations: Methodology and Results
- Qualitative Analyses: Energy Imbalance Service, Market Power
- Aquila Case Wholesale Impacts
- Discussion

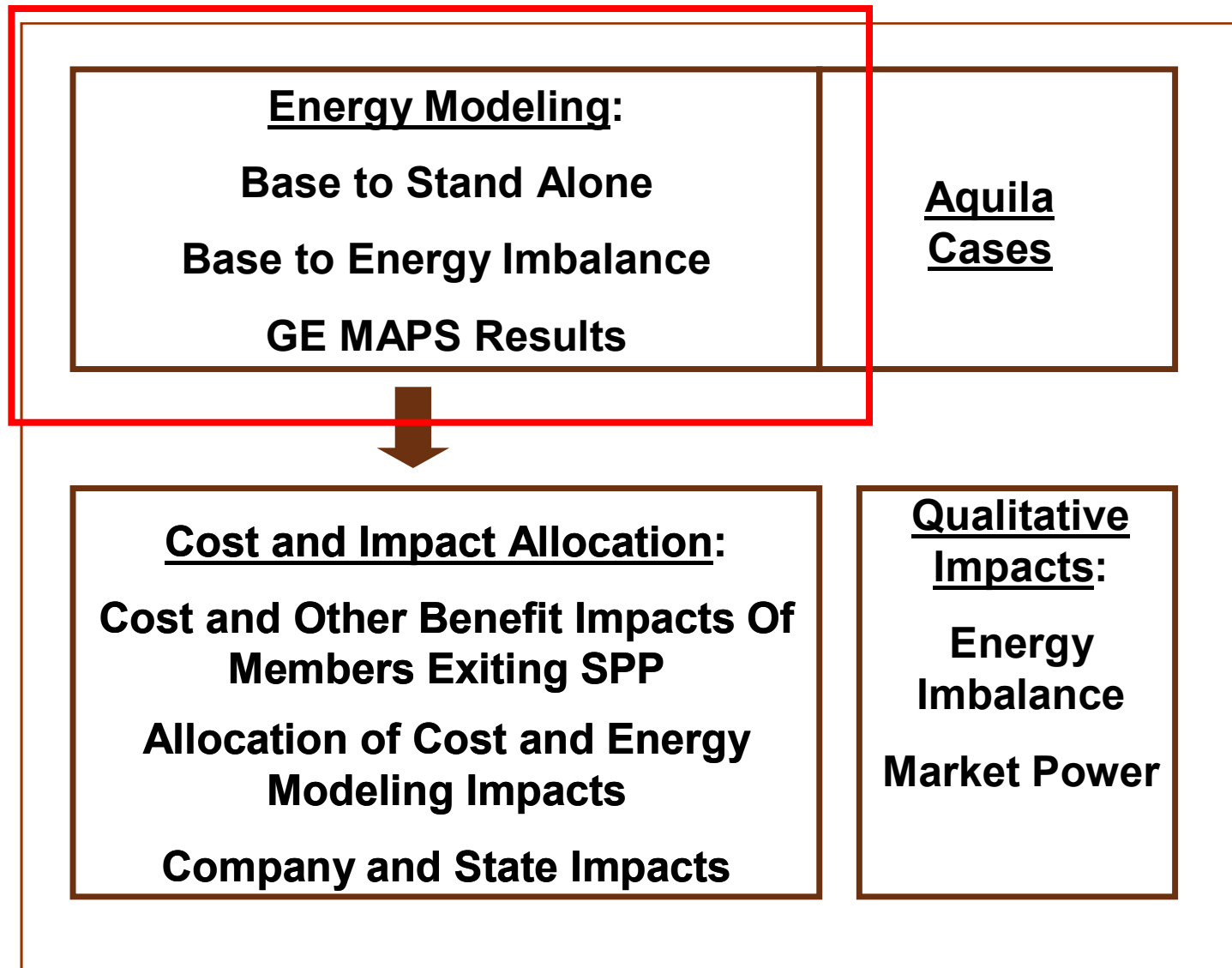
Cost-Benefit Analysis Background

- Directed by the RSC to study impacts of Energy Imbalance Market and of RTO status
- RFP Apr 04, Charles River Associates (CRA) team selected, steady work on the effort during 2004 & 2005 to date
- Approaches defined in Assumptions memos
- Significant interplay between CBTF-Consultant and SPP-Consultant throughout study period
- Draft findings and reports provided, reviewed and discussed as part of RSC process
- Final Report April 23, 2005

CBA General Approach: Study Elements



Outline: Wholesale Modeling: Methodology and Results



Wholesale energy modeling methodology

- Fundamental transmission system security-constrained unit commitment and dispatch analysis using MAPS
- Modeling required detailed set of inputs
 - 2002 hourly load shapes from CRA database of FERC 714 filings
 - Gas and oil forecasts; coal forecasts from third party (Platt's)
 - Transmission system configuration from SPP load flow
 - Environmental adders based on forecast emissions values (EPA Clean Air Markets database)
 - New generation additions already under construction based on public information and validated with the CBTF
 - Generation bids based on marginal cost (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits)

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

- Simulation scenarios were manipulated to represent “cases”
- Difference in cases reflected impacts

	Base Case	EIS Case	Stand-Alone Case
Application of wheeling charges	No wheeling charges between SPP members	No wheeling charges between SPP members	Area-to-area wheeling charges
Specification of flowgate capacity	Reduced (by 10%) flowgate capacity	Full flowgate capacity	Reduced (by 10%) flowgate capacity
Dispatch of non-network generating units	Sub-optimal	Optimal	Sub-optimal

Note: no “hurdle rates” used in study; rather modeling constructs emulating actual system/market characteristics

EIS case differences: Optimal and Suboptimal Cases

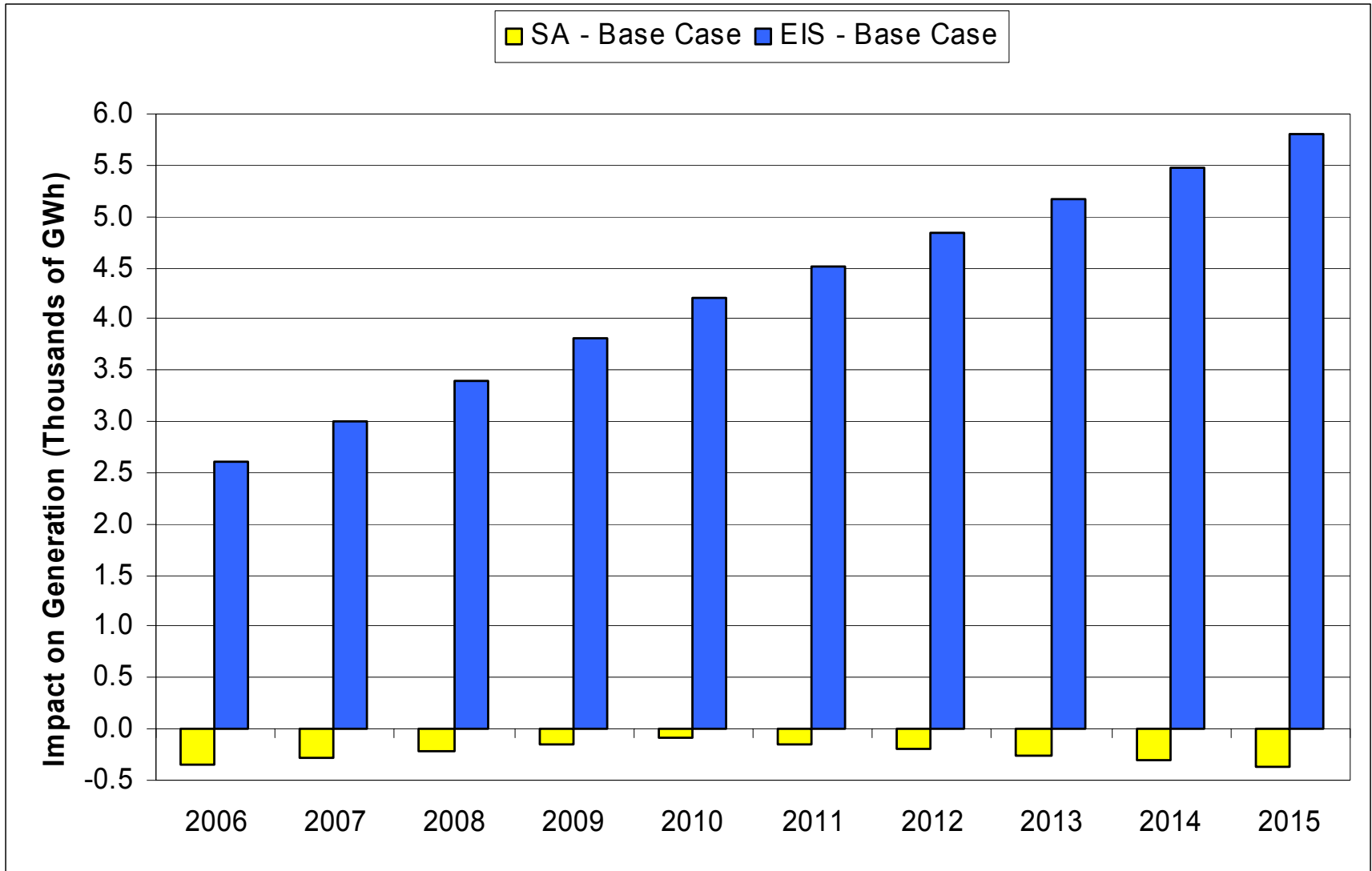
Two distinctions with EIS Case

1. Effective Flowgate Capacity – 10% reduction in Base and Stand-Alone cases
 - reflects the inefficiency of congestion management through the TLR process
 - Uncertainty of which units dispatched
 - Time lag in process
 - 10% figure based on historical tie-line flows during TLR events
2. “Suboptimal” Dispatch of Non-Network Generating Units
 - In Base and Stand-Alone cases transmission access priority granted to network services resources
 - Non-network resources dispatch subject to remaining transmission system capacity
 - In simulation, the output of each non-network resource was limited such that the resource’s impact on the constrained transmission line did not exceed 5% of the line’s rating
 - In EIS case, all resources are dispatched economically

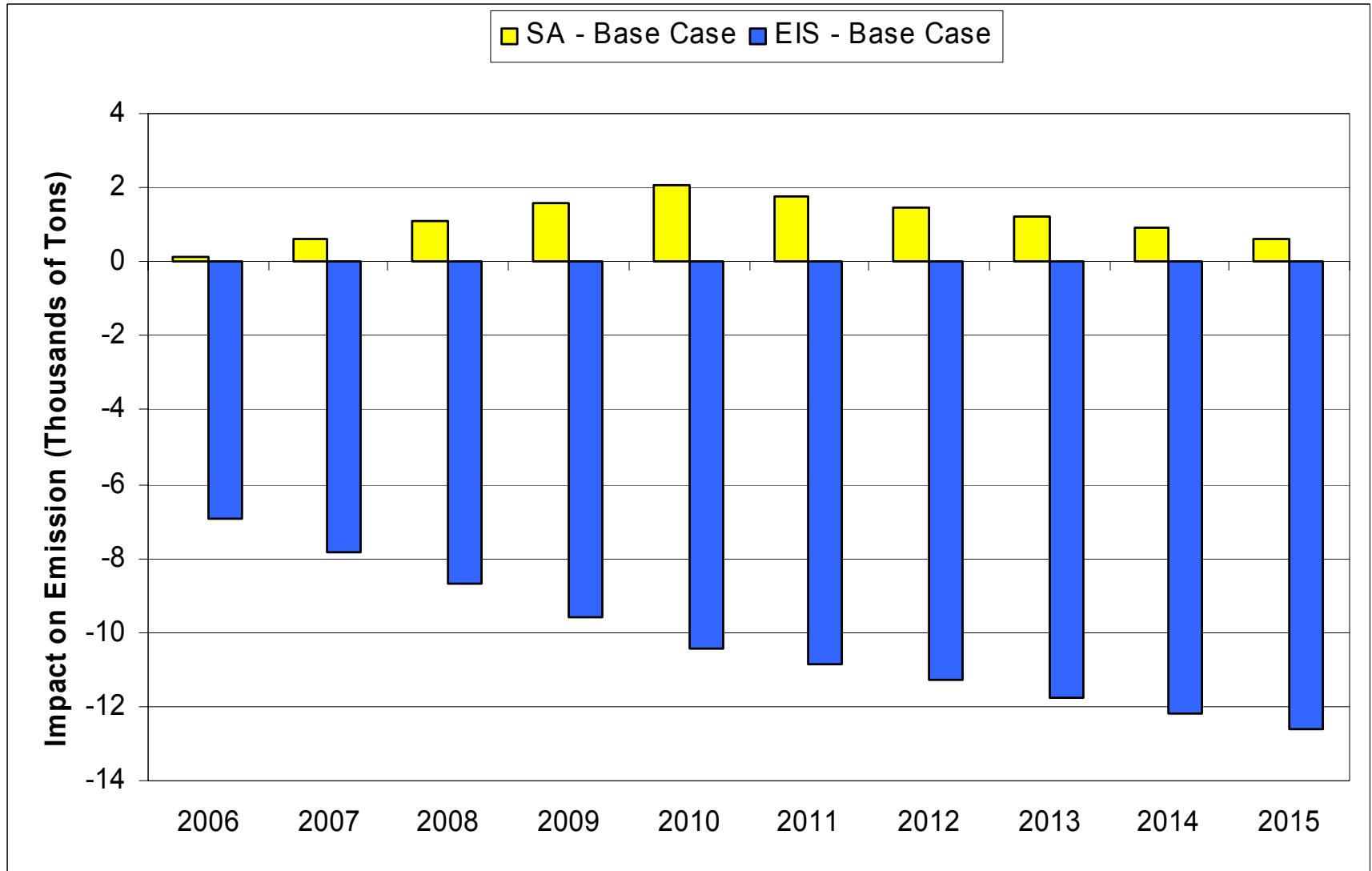
Wholesale energy modeling outputs

- Metrics
 - Physical metrics – generation, emissions
 - Production cost
 - Prices
- Outputs to Allocation models

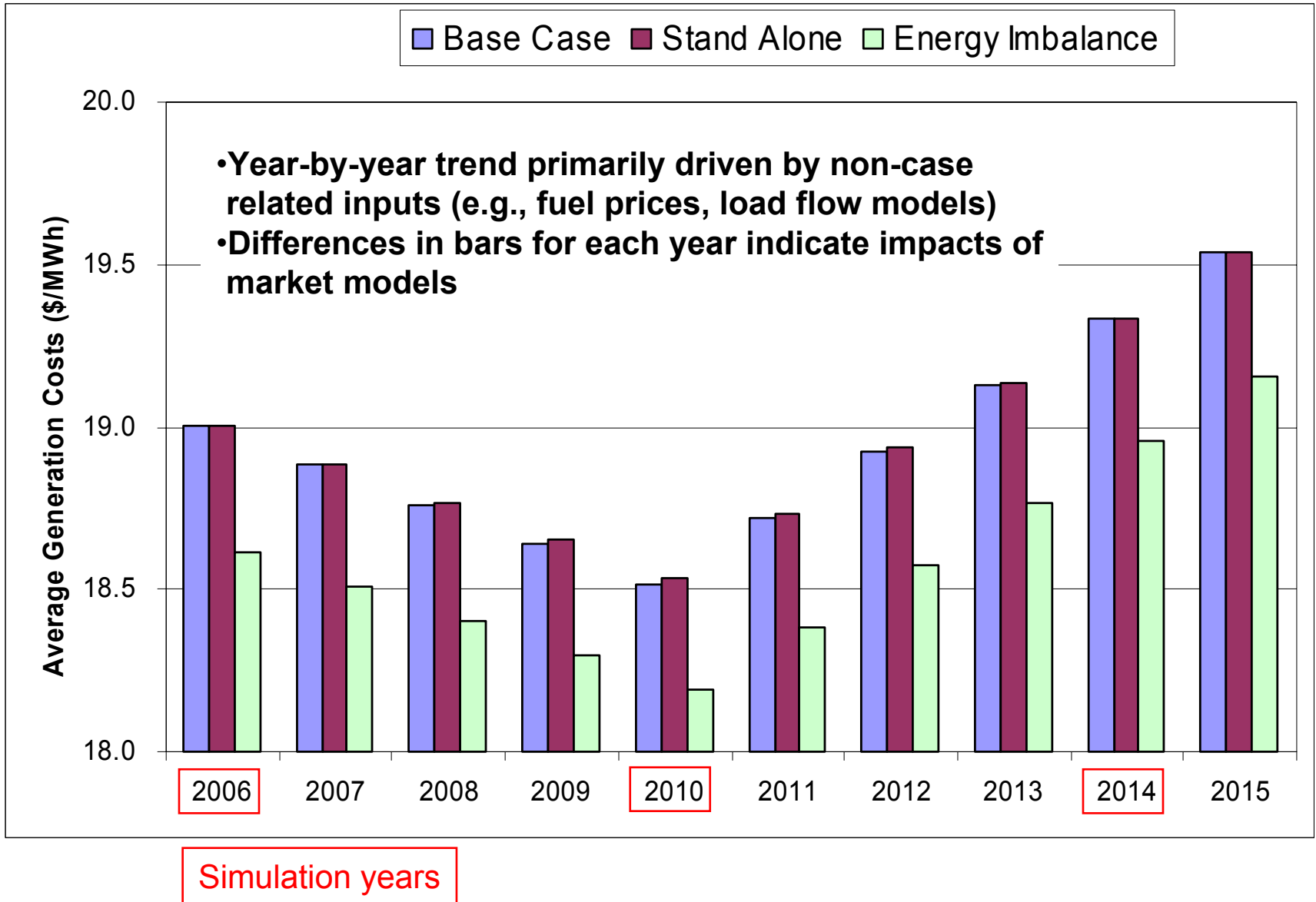
Impact of Cases on Generation in SPP Region: more efficient cases result in more generation in SPP



Impact of Cases on Emissions in SPP Region: more efficient cases reduced emissions in SPP

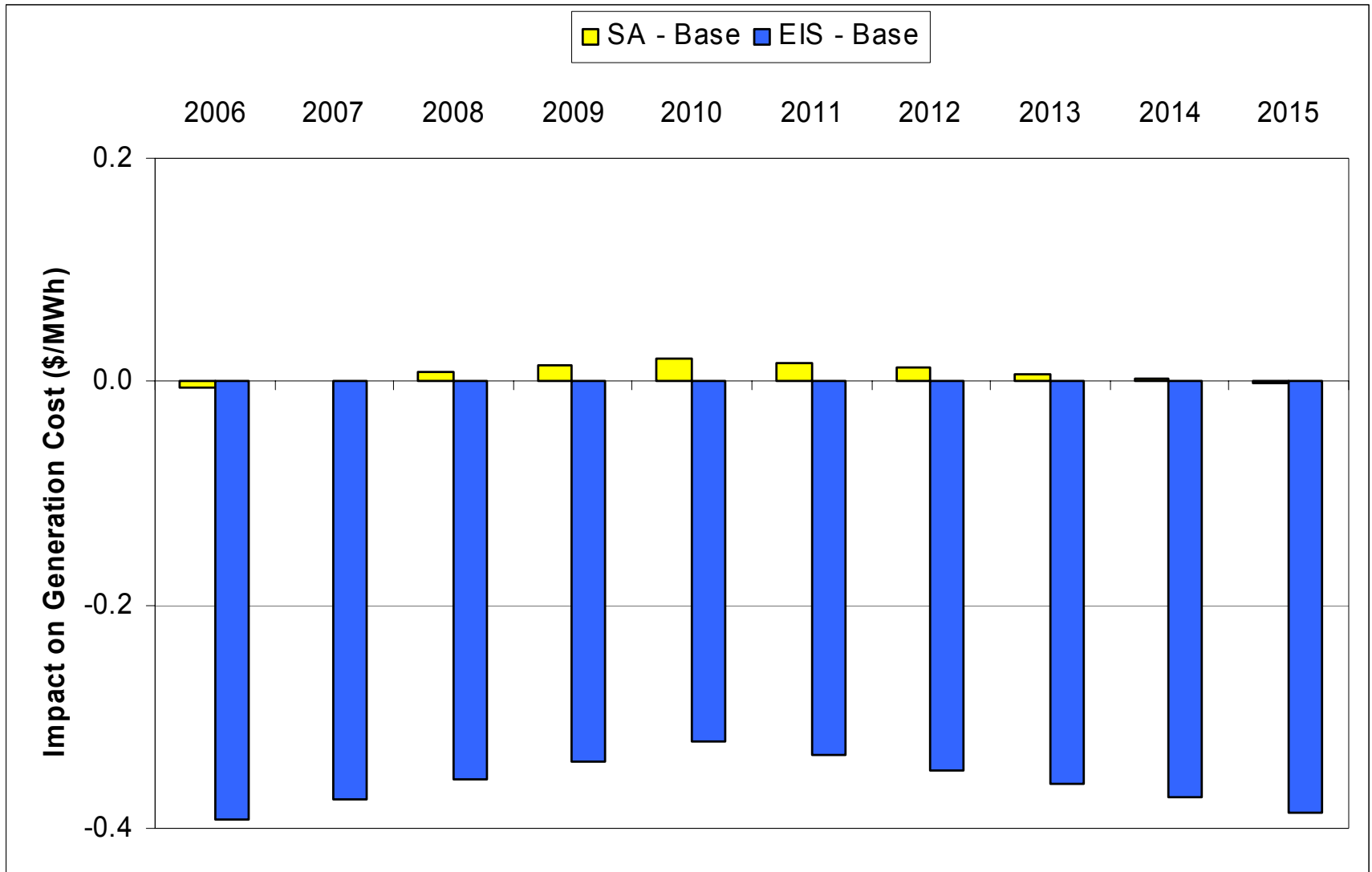


SPP Region-wide Generation Cost (\$/MW) by Case – Primary wholesale metric

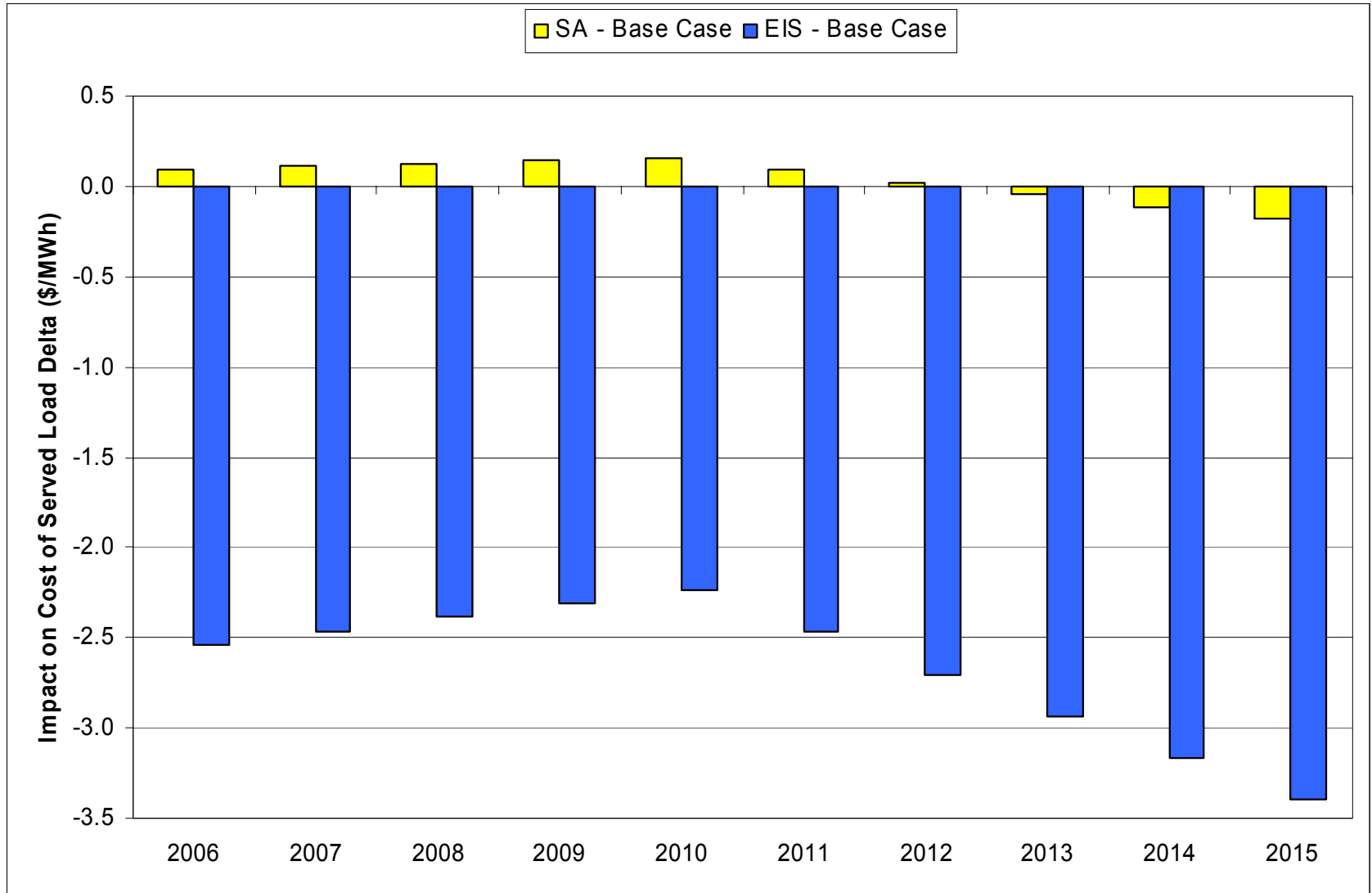


SPP Region-wide Generation Cost (\$/MWh) Cost Differences

- EIS case results in ~ 2% production cost savings



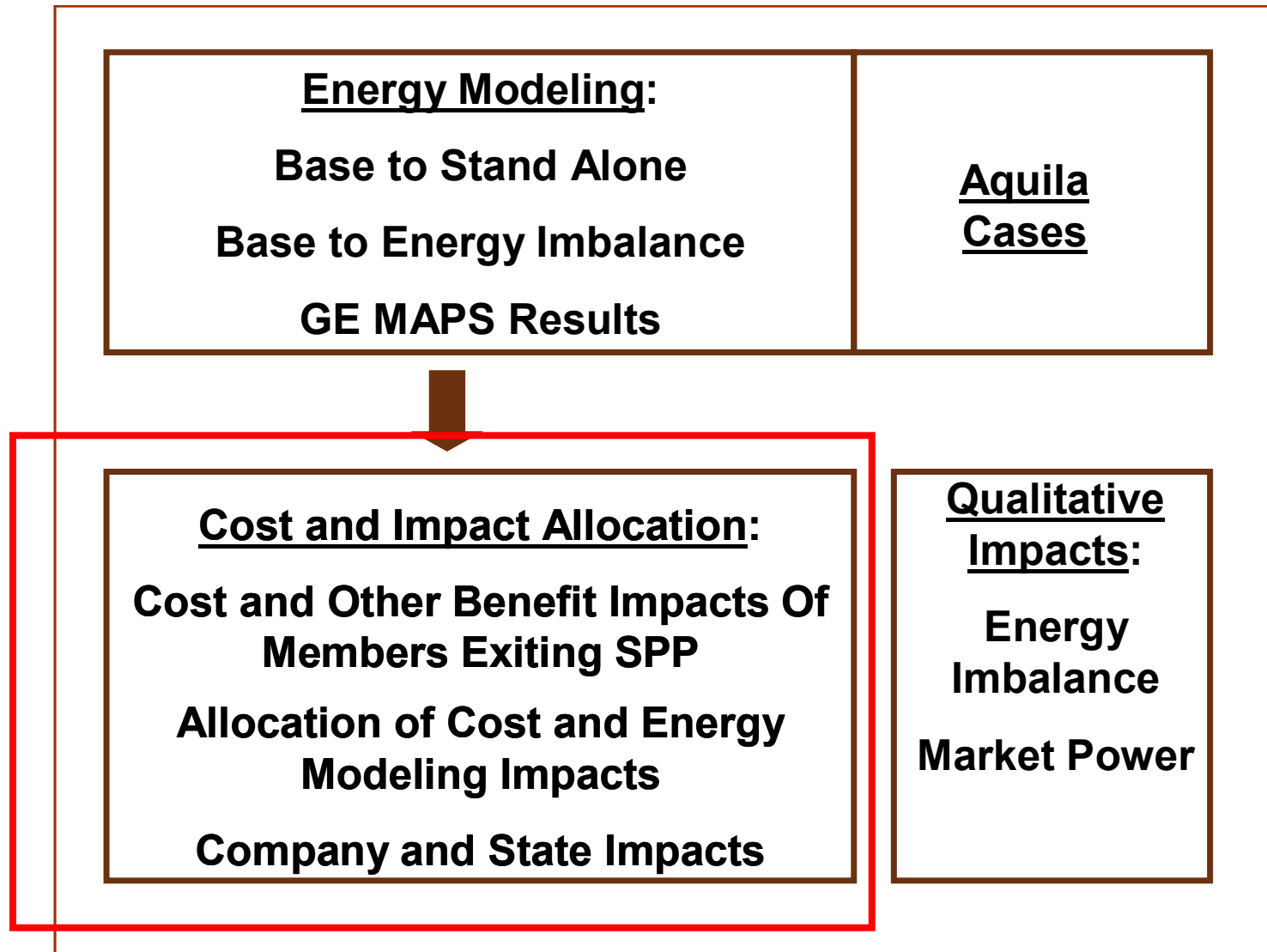
SPP Regional Load Spot Energy Price Differences – EIS Case results in ~ 7% reduction in spot load energy price



Wholesale simulations feed allocation model with energy impacts

- Generation
- Generation cost
- Nodal locational marginal prices
- Hourly tie-line flows
- Annual generating plant reports (dispatch, cost, revenue)
- Load

Outline: Cost Impact and Allocations: Methodology and Results



Overview of Metrics Used to Analyze Costs and Benefits

In this study, the benefits and costs associated with moving from the Base Case to the Stand-Alone case and to the EIS Market Case for SPP members are divided into three basic categories

- System Efficiency/Trade Benefits
- Transmission Charge Impacts
- Administrative Costs

Each is discussed in turn in the following slides

Overview of Metrics Used to Analyze Costs and Benefits: MAPS outputs

- Out of the MAPS runs, a number of metrics are produced:
 - Flows between control areas
 - Generation production costs,
 - Generator LMP
 - Loads LMP
- These cost and revenue metrics are useful in assessing wholesale market impacts (e.g., production cost savings = social welfare gains) and can reflect individual impacts to the extent that retail customers are paying market price and generators are receiving market revenues
- However, the metrics do not account for hedging arrangements, such as cost-of-service regulated retail prices or FTRs

Overview of Metrics Used to Analyze Costs and Benefits: Trade Benefits

- To assess the costs and benefits under the cost-of-service ratemaking prevailing in the SPP region requires post-processing of the MAPS results.
- In the post-processing stage, we make the following assumptions:
 - Retail customers pay cost-based regulated prices in all cases.
 - All regulated generator surplus is passed through to retail customers.
 - Differences in load and generator prices within a control area are covered by retail customer's internal transmission rights.

Overview of Metrics Used to Analyze Costs and Benefits: Trade Benefits

- Total energy market benefits will be equal to the total savings in production cost
 - We have not considered capacity market benefits in this study
- Production cost savings are due to increased transactions between control areas, *i.e.*, these are “trade benefits”
 - For example, the elimination of intra-SPP wheeling charges lowers trade hurdles, and results in production cost savings
- The key question is who gets these trade benefits between control areas:
 - Exporting control areas benefit by selling power at a price higher than the cost incurred to produce the power
 - Importing control areas benefit by buying power at a price lower than the cost that would have been incurred to produce the power

Overview of Metrics Used to Analyze Costs and Benefits: Trade Benefits

- In the SEARUC study, CRA used the difference in prices between the exporting and importing regions and the tie-line flow between the regions, and applied a 50-50 split-savings to allocate trade benefits
 - The SEARUC method was applied for trade between large regions (e.g., SPP, Entergy, Southern, GridFlorida)
- Our efforts to apply a similar method inside the SPP region to individual TOs were confounded by significant levels of loop flow on the intra-SPP tie-lines from high to low price areas
 - To implement this method would require additional study to determine how the loop flow issue could be addressed
- We therefore estimated trade benefits using the change in generation of each utility control area as a measure of additional trade
 - Utility areas that had changes (up or down) in generation are assumed to be making additional trades. This is consistent with a 50-50 sharing assumption, albeit at a higher level of aggregation than that used in the SEARUC study

Overview of Metrics Used to Analyze Costs and Benefits: Trade Benefits

- The EIS case, in which there is considerable additional merchant generation in many of the SPP control areas, required some additional allocation assumptions within the control areas
 - Merchants are unlikely to participate in the EIS market as a sole source of revenue; instead merchants would continue to seek contractual arrangements with utilities on behalf of native load
- We therefore assumed that merchants and the utility within each control area would share in the control area trade benefits based on the change in generation (again, up or down). Again, this is consistent with a 50-50 buyer/seller sharing rule, albeit inside the control area
 - The resulting merchant share of the benefits was then allocated 50-50 between the merchants and native load on the presumption that contractual arrangements would be made share to these benefits
- These Trade Benefits must then be compared to Costs (e.g., administrative costs and wheeling revenue impacts)

Overview of Metrics Used to Analyze Costs and Benefits: Transmission Charge Impacts

- The MAPS runs were analyzed to calculate the wheeling charges that would be collected and paid by each control area under the SPP Tariff
 - In the EIS and Base cases, only transactions to/from control areas not under the SPP tariff are assessed wheeling charges
 - In the Stand-Alone case, transactions to/from control areas under the SPP tariff are also assessed wheeling charges
- The wheeling charges are assessed on hourly “out” transactions, e.g., exports
 - The wheeling charge is paid by the importing control area
 - The wheeling revenue accrues to the transmission owner in the exporting control area

Overview of Metrics Used to Analyze Costs and Benefits: Transmission Charge Impacts

- The additional transmission revenue and additional costs for each control area under the SPP tariff are derived based on the inter-control area tie-line flows in the MAPS runs
 - The total additional revenues and costs are not equal when aggregated over all SPP control areas because of payments to and revenues from adjoining control areas
 - The net amount is a benefit/(cost) to the control area.
 - The benefit is assumed to accrue to the native load of the transmission owner through adjustment mechanisms to the transmission revenue requirements
 - In effect, native load is assumed to pay for the transmission revenue requirement net of the wheeling rate impact

Overview of Metrics Used to Analyze Costs and Benefits: Administrative Costs

- We identified six categories of administrative costs that will be incurred by SPP and/or its members when moving from the Base case to the Stand-Alone or EIS case
 - Costs Relevant to Stand-Alone Case
 - Additional costs incurred to supply the current SPP Reliability and Transmission Provider Functions
 - FERC Fees: The FERC Fees charged to RTOs are higher than those charged to non-RTO utilities
 - Cost Allocation: The method for allocating new transmission project capital costs among SPP TOs would differ
 - Withdrawal Costs: The charge to SPP members that withdraw from SPP
 - Costs Relevant to EIS Case
 - SPP EIS Costs: The costs incurred by SPP to develop and operate the EIS market
 - Participant EIS Costs: The costs incurred by SPP members to participate in the EIS Market

EIS Market Case Results

EIS Market Case Results

- The EIS market yields \$1.2 billion in production cost savings over the 10-year study period
 - This savings is for the entire Eastern Interconnect
- Through the allocation process, \$614 million of trade benefits accrues to the TOs under the SPP tariff
 - These benefits are roughly 2.5% of total SPP production costs
- EIS implementation costs are \$212 million over the study period.
 - This includes both SPP and internal utility costs
 - SPP costs are roughly \$20 million per year, declining to \$16 million per year in the later years of the study period
- Overall benefits are \$373 million to the TOs under the SPP tariff

Benefits to TOs under the SPP Tariff, by Category

In millions of 2006 present value dollars

Positive numbers are benefits

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

EIS Market Case Results

- The process described earlier was used to calculate EIS market benefits for the individual TOs under the SPP tariff. The individual TO results vary significantly
- The EIS market benefits for AEP, Empire, OGE and SPS are fairly significant, while those for KCPL, Westar Energy, SPWA, GRDA and Springfield, Missouri are relatively small
- The difference in benefits in the EIS case is largely driven by the allocation of trade benefits
- Those utilities with large positive impacts tend to have a relatively significant impact on the dispatch of their generating units under the institution of an EIS market

EIS Market Case Results

Benefits to Individual TOs under the SPP Tariff

In millions of 2006 present value dollars

Positive numbers are benefits.

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	70.0
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	5.3
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

EIS Market Case Results

- Benefits by TO for the six IOUs under the SPP tariff were allocated between wholesale and retail customers, and then to individual state retail customers primarily using a net energy for load ratio share
- To improve the allocation, AEP's trade benefits were first allocated to the PSO and Swebco operating companies prior to allocation to states
 - The trade benefit allocation is largely a function of the change in generation between cases, and the change in generation for the PSO units is much greater than that of the Swebco units in the EIS case
- To the extent that there are agreements in place that share costs between IOU operating companies, this was not taken into account in this study

IOU Retail Customer Benefits, by State

In millions of 2006 present value dollars

Positive numbers are benefits.

Arkansas	9.2
Louisiana	(3.8)
Kansas	8.3
Missouri	60.0
New Mexico	9.2
Oklahoma	141.7
Texas	26.6

Stand-Alone Case Results

Stand-Alone Case Results

- Stand-Alone case yields \$52 million of additional production costs over the 10-year study period
 - This savings is for the entire Eastern Interconnect.
- Through the allocation process, \$21 million of lost trade benefits (i.e., additional costs) accrues to the TOs under the SPP tariff
 - This is about 0.1% of total SPP production costs.
- The transmission wheeling impacts are large, but the charges and revenues are largely offsetting across the SPP tariff region
- The additional costs incurred by the TOs to perform SPP reliability/transmission functions on a Stand-Alone basis are \$46 million
- FERC charges are estimated to be \$27 million less on a Stand-Alone basis given current FERC policies
- Withdrawal obligations payable to SPP would be \$47 million
- Overall additional costs of the Stand-Alone case are \$70 million to the TOs under the SPP tariff over the study period

Stand-Alone Case Results

Benefits to TOs under the SPP Tariff, by Category

In millions of 2006 present value dollars

Positive numbers are benefits

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

Stand-Alone Case Results

- The benefits by TO are presented both with and without wheeling impacts
- Wheeling impacts were estimated using MAPS tie-line flows. In the Stand-Alone case, wheeling charges are assessed on intra-SPP flows
 - That is, there are wheeling charges on intra-SPP flows in the Stand-Alone case, but not in the Base Case
 - Thus, the intra-SPP loop flow discussed previously has the potential to distort the intra-SPP wheeling impacts found using tie-line flows
- As a result, there is considerable uncertainty associated with the wheeling impacts by TO in the Stand-Alone case
 - The results with wheeling impacts included should be viewed as indicative or representative, subject to further investigation into effects of loop flow on individual company wheeling impacts

Stand-Alone Case Results

Benefits to Individual TOs under the SPP Tariff

In millions of 2006 present value dollars

Positive numbers are benefits

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

Stand-Alone Case Results

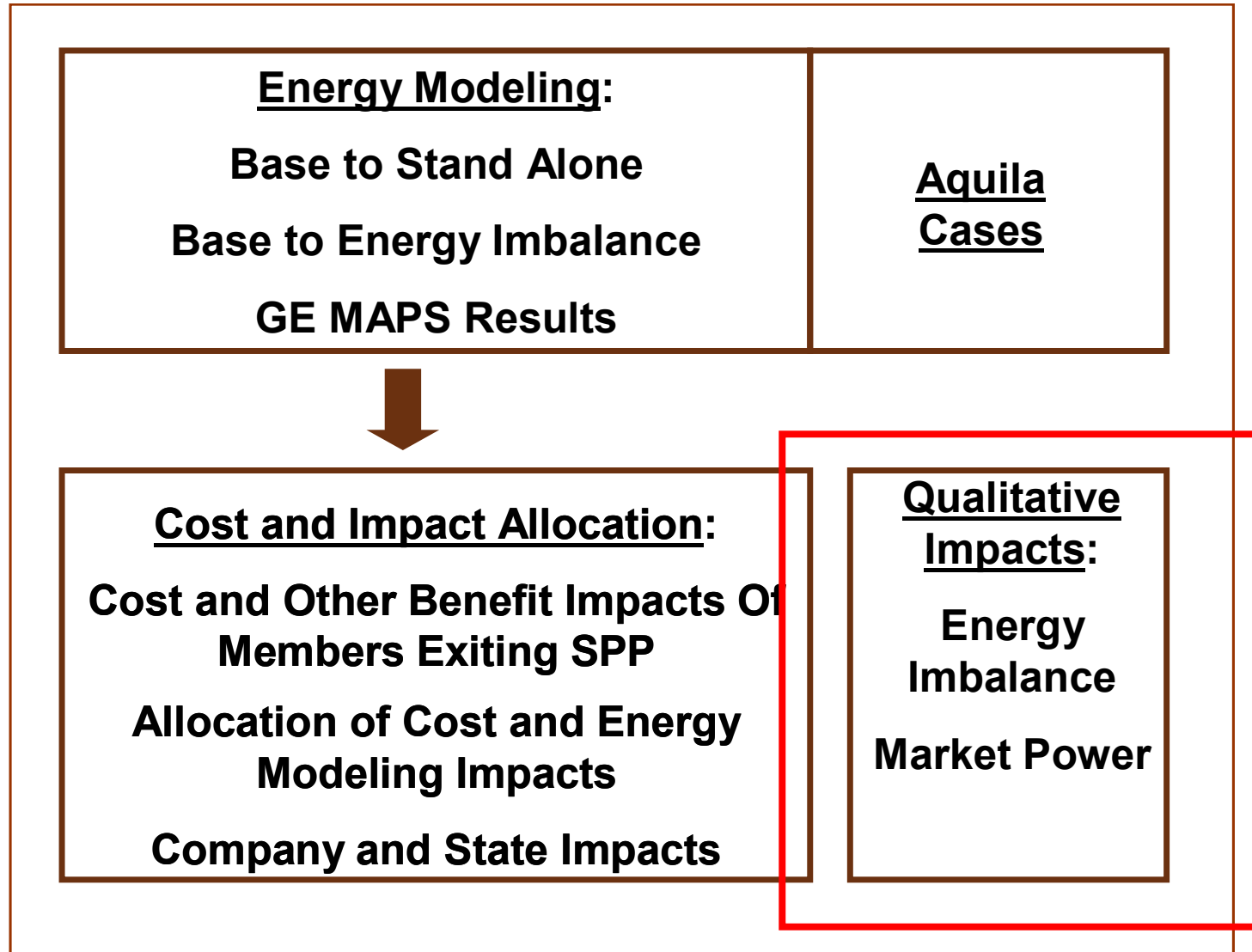
IOU Retail Customer Benefits, by State

In millions of 2006 present value dollars

Positive numbers are benefits

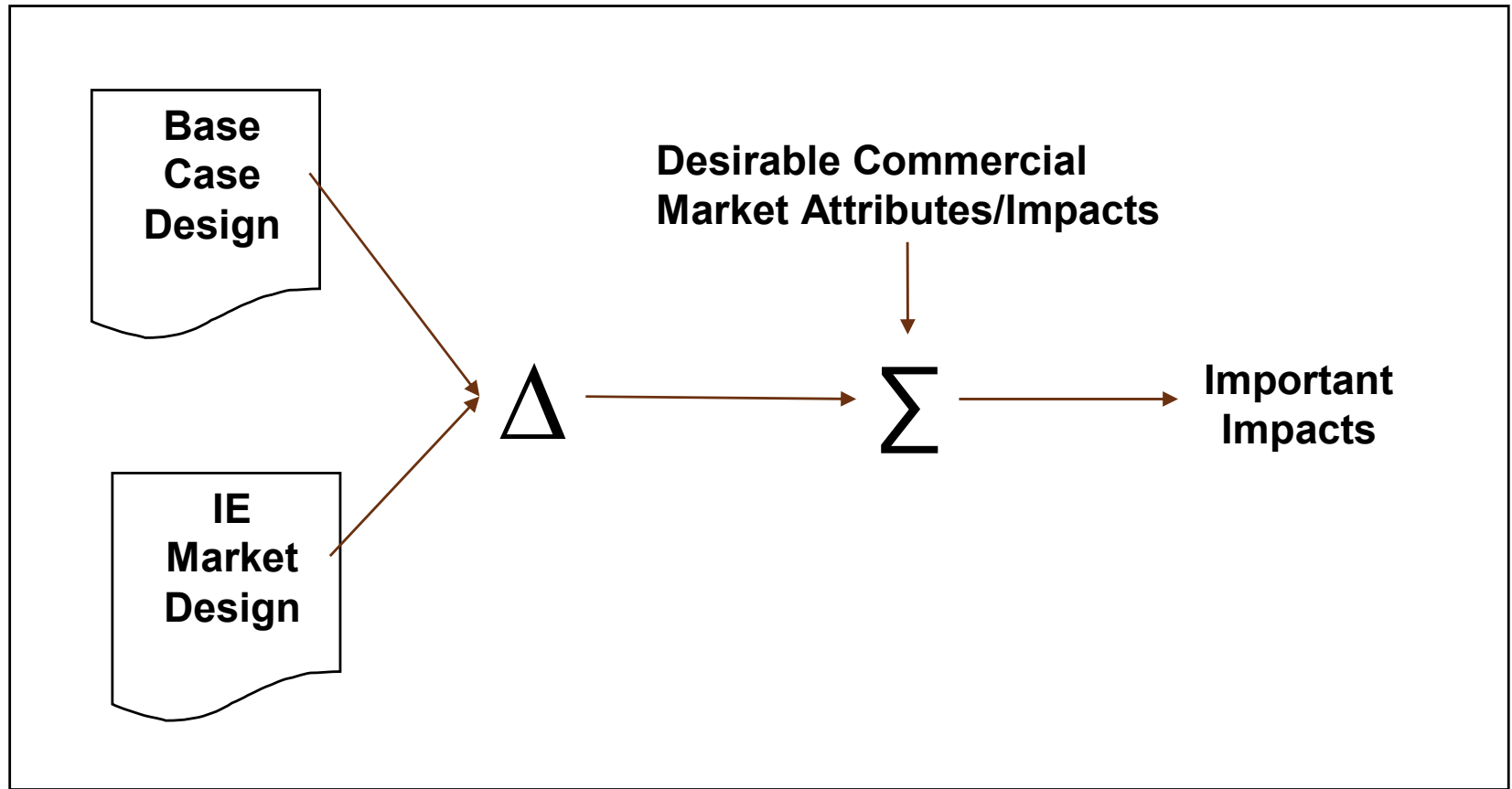
	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

Outline: Qualitative Analyses: Energy Imbalance Service, Market Power

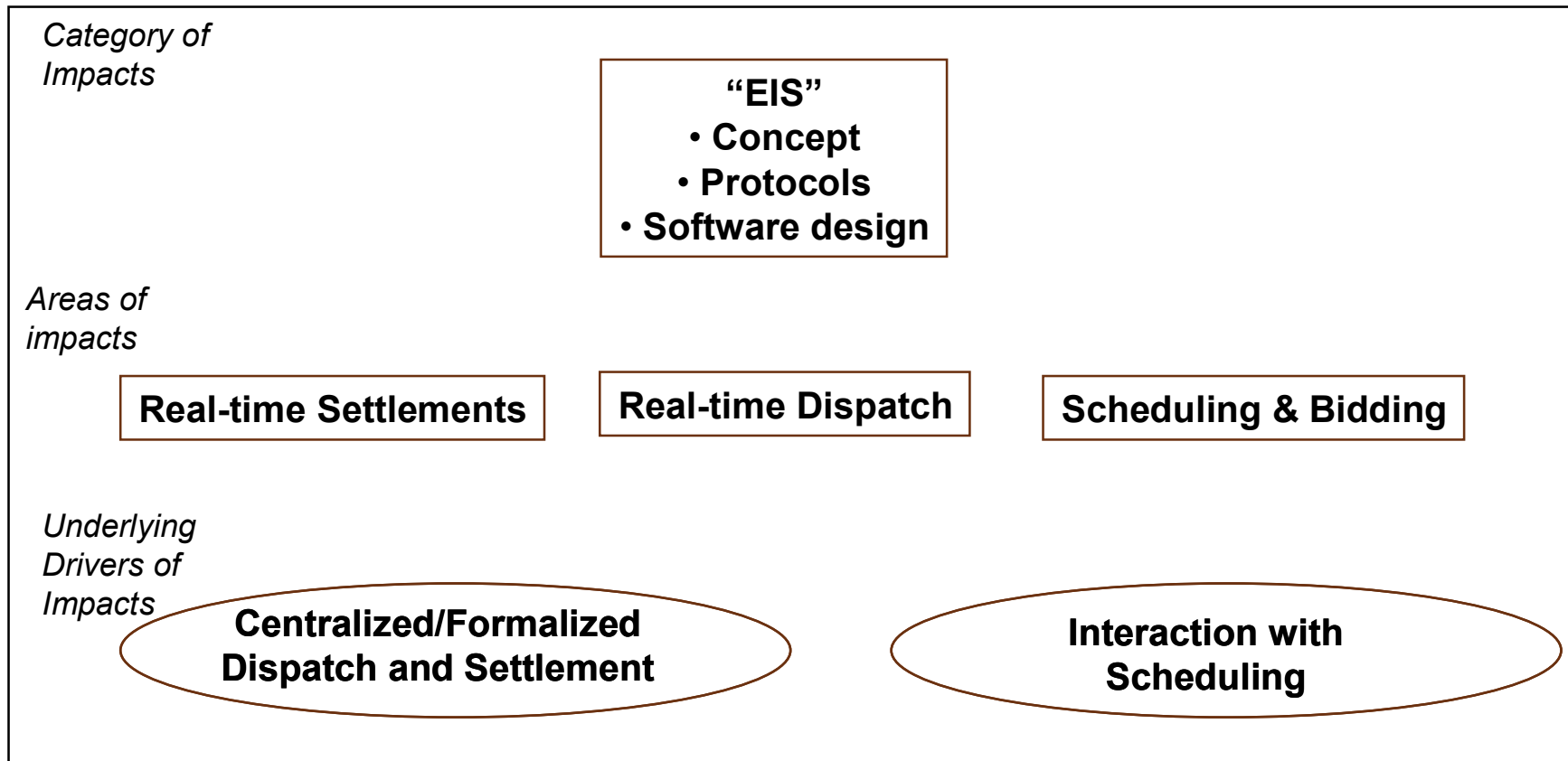


Qualitative analysis of Energy Imbalance Market Impacts

EIS Qualitative Assessment Methodology



EIS Changes - Various Views



Areas of impact considered for EIS qualitative analysis

- [Facilitate Development of] **Competitive Markets**
- [Minimize] **Discriminatory Environment**
- [Increase] **Efficiency of Production**
- [Promote] **Efficient Resource Expansion**
- [Promote] **Efficient Grid Expansion**
- [Neutralize] **Opportunities to Exercise Market Power**
- [Enhance] **Grid Reliability**
- [Facilitate] **Ability to Conduct Business**
- [Minimize] **Costs and Administrative Burdens**

EIS qualitative analysis findings

Major qualitative impacts are as follows:

- **Pluses:**
 - Improved transparency and improved price signals
 - Centralized management of inadvertent energy will likely be subject to additional production efficiencies that are not captured in the quantitative results of the energy modeling

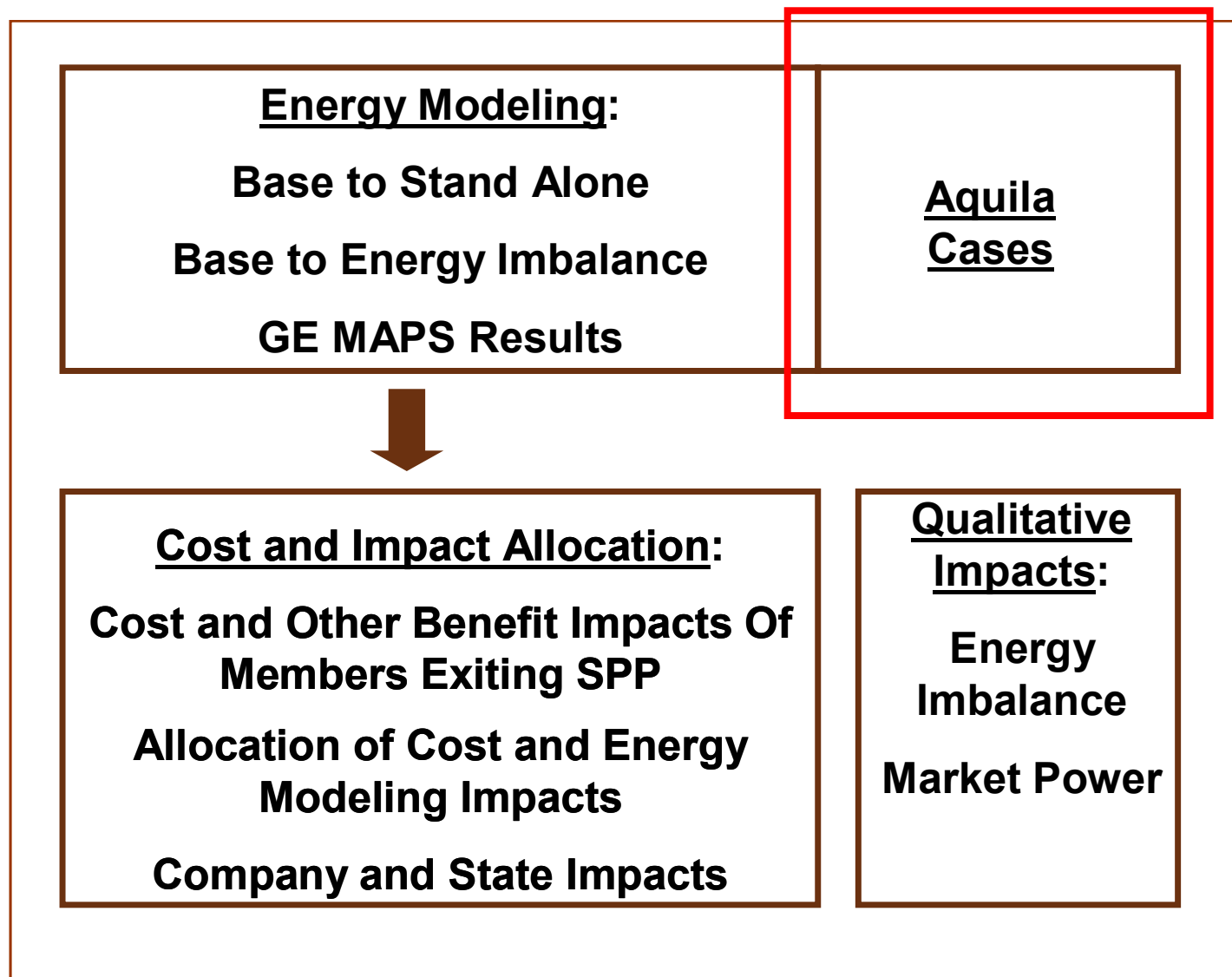
- **Negatives:**
 - Added complexities may produce adverse impacts during a transition period of roughly 3 to 5 years
 - Explicit imbalance energy prices creates risks for market participants associated with not following schedules
 - Scheduling requirements may impede the development of competitive markets if the scheduling requirements are overly burdensome

Qualitative Analysis of Market Power Impacts

Market Power Considerations

- CRA did not conduct a formal study of market power in conjunction with this cost benefit study
- There are two primary factors that suggest market power is not likely to become a significant consideration under the EIS market in particular
 - The provision for an ongoing market monitoring function within SPP and for a separate, independent monitor
 - The lack of incentive for the exercise of market power under the economic conditions likely to prevail under the EIS market
- The continuation of cost-based regulation for most of the output of generation in the SPP region means that the EIS market is not likely to augment the incentive to exercise market power in a significant way
 - Generation owners in the SPP would have little incentive to withhold generation for the EIS for the purpose of increasing the market-clearing price in that market
 - The output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price
 - Without the incentive to exercise market power, which would be lacking under cost based regulation, the issue of market power is likely to be a minor consideration in the EIS market

Outline: Aquila Case Wholesale Impacts



Aquila wholesale impacts assessed for 2006

- The Aquila Sensitivity cases: Aquila in SPP rather than in the MISO RTO
 - Missouri Public Service (MIPU)
 - WestPlains Energy (WEPL)
- Modeling differences relative to non-Aquila Cases
 - Wheeling rates: Aquila – SPP rates eliminated, Aquila – MISO rates instituted
 - Reserves: total reserve requirements (largest contingency plus one-half the next largest contingency) for SPP do not change between the two cases, but requirement is over a greater load base, reducing each the requirement of each SPP company
 - Commitment: in the Aquila sensitivity case, units in WEPL and MIPU are committed against load in SPP
- Wholesale energy results were generated for the Aquila case for both the Base and EIS cases
- No specific analysis of cost or benefit allocation was performed

SPP and Aquila Regional Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation in SPP + Aquila (GWh)	204,865	206,637	(1,772)	207,406	209,422	(2,016)	2,541	2,785	(244)
Average Generation Cost (\$/MWh)	\$ 19.07	\$ 19.12	\$ (0.05)	\$ 18.68	\$ 18.74	\$ (0.06)	\$ (0.39)	\$ (0.38)	\$ (0.01)
Normalized Generation Costs (\$million)	\$ 3,907	3,917	\$ (10)	\$ 3,827	3,839	\$ (12)	\$ (80)	\$ (78)	\$ (2)
Per MWh Spot Energy Cost	\$ 40.59	\$ 40.75	\$ (0.16)	\$ 38.10	\$ 38.35	\$ (0.26)	\$ (2.49)	\$ (2.40)	\$ (0.09)

- SPP regional generation costs are \$10 million to \$12 million lower with Aquila in MISO (~0.25% of the region's total generation cost)
- SPP Spot marginal energy costs are \$0.16/MWh to \$0.26/MWh lower with Aquila in MISO
- Relatively small EIS – Base, MISO – SPP values indicate that EIS case is not sensitive to Aquila's choice

Aquila Companies' Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation Aquila (GWh)	6347	6295	52	6280	6307	(27)	(67)	12	(79)
Average Generation Cost Aquila (\$/MWh)	\$ 21.07	\$ 20.80	\$ 0.27	\$ 20.79	\$ 20.71	\$ 0.08	\$ (0.28)	\$ (0.09)	\$ (0.19)
Normalized Generation Costs Aquila (\$million)	\$ 133.72	\$131.99	\$ 1.73	\$ 131.94	\$131.43	\$ 0.50	\$ (1.79)	\$ (0.56)	\$ (1.22)

- Aquila generates more if in MISO under the Base case, but more if in SPP if SPP has EIS. (Change in Aquila generation < 1% in both cases)
- Aquila shows generation cost benefits of being a member of SPP, and those benefits are higher under the Base case than under the EIS case (1.3% and 0.3%, respectively)
- Also notable: while the SPP region's generating costs would be lower with Aquila in MISO (\$10 million in the Base case), Aquila's generating costs would be lower with Aquila in SPP (\$1.7 million in the Base case)

Outline

- Background of Cost-Benefit Analysis
- Study Structure
- Wholesale Energy Modeling: Methodology and Results
- Cost Impact and Allocations: Methodology and Results
- Qualitative Analyses: Energy Imbalance Service, Market Power
- Aquila Case Wholesale Impacts
- Discussion