ASSESSMENT OF SPP'S MARKET MONITORING PLAN AND MARKET POWER MITIGATION MEASURES FOR THE SOUTHWEST POWER POOL (SPP) ENERGY IMBALANCE SERVICES (EIS) MARKET

Prepared By:

Boston Pacific Company, Inc.
As the External Market Advisor

December 17, 2007

TABLE OF CONTENTS

SECTION I: INTRODUCTION AND SUMMARY

PURPOSE

Under its 2007 External Market Advisor's (EMA) Services Agreement, Boston Pacific is required to provide an assessment of the Market Monitoring Plan and Market Power Mitigation Measures for SPP's Energy Imbalance Services (EIS) Market. As part of the FERC's Order Approving SPP as a Regional Transmission Organization (RTO), the FERC required SPP to provide a market monitoring plan that contained suitable market power mitigation measures before SPP's imbalance market could be implemented.[1] The FERC provided guidance in the development of SPP's Plan and Measures, and subsequently approved them. Given this, our purpose is not to rewrite or to provide a ground-up review of the Plan and Measures; rather we would like to assess whether they have been effective in mitigating possible market power abuse. The EMA's contract reflects this same view when it states, "the EMA will assess the effectiveness of the Plan and Measures by asking whether stated goals are being met."[2]

Given this, Boston Pacific has defined two purposes for this report. The first, and more important, is to assess the effectiveness of the current Plan and Measures. To do so, we will focus on the *results* of the Plan and Measures. That is to say, we will examine the EIS Market to see if it has helped foster and maintain a competitive marketplace. To this end, we will use current metrics, such as those included in the Monthly and Quarterly Reports, to determine whether there is any evidence of market power concerns.

The second purpose is to provide a list of enhanced or new metrics for consideration by the SPP Market Monitoring Unit (MMU). The MMU now has significant experience monitoring SPP's markets around the clock. Given this experience, the MMU has some preliminary thoughts on additional metrics that could enhance their ability to monitor SPP. Based on our conversations with the MMU, our own expertise in monitoring, and our review of metrics in other RTOs and Independent System Operators (ISOs), we give brief descriptions of a range of other possible metrics.

SUMMARY OF THE EFFECTIVENESS OF THE PLAN AND MEASURES

Market Prices

Market power is defined as the ability to profitably raise prices, for a sustained period of time, above the level that would otherwise prevail in a competitive market. For this reason, any assessment of possible market power concerns has to start with a look at EIS Market prices. Current metrics come at this from at least three perspectives.

---

[1] *See* 106 FERC ¶ 61,110. *Order Granting RTO Status Subject to Fulfillment of Requirements* at P 173.
[2] *See* Boston Pacific Services Agreement Contract Year 2007 at Exhibit B.

The first perspective is to compare EIS Market prices to those in two neighboring and more mature, real-time energy markets: those operated by the Midwest Independent Transmission System Operator (MISO) and the Electric Reliability Council of Texas (ERCOT). We do not expect the prices in these markets to be identical to those in SPP because of differences in resource mix and patterns of demand. However, prices in these two markets give us one measure of *competitive* market prices and, for that reason, we want EIS Market prices to be in-line with MISO and ERCOT prices. We take comfort in the fact that prices in the first seven months of EIS Market operation have consistently been in-line with prices in MISO and ERCOT. Specifically, the simple average price in the EIS Market over the first seven months was $50.21/MWh which is 6.9% below that for ERCOT and 1.5% above that for MISO. Also, when we look month-by-month and hour-by-hour, rather than for all seven months as a group, the EIS Market prices are once again in-line with those in MISO and ERCOT.

The second perspective taken on EIS Market prices is to assess how they vary across the SPP footprint. Prices vary across locations when there is transmission congestion which breaks the SPP-wide market into submarkets. Looking first at the locations represented by the ten load settlement locations, we see that all of these have simple average hourly prices which are within 15% of the SPP-wide simple average hourly price of $50.21/MWh. Another look at the variation across locations takes a more granular view. In this view, we look at prices at every price location – not aggregated to load settlement locations – and for each five-minute dispatch interval – not only the hourly prices. Here we see that 96.7% of these locational prices by interval fall within what can be seen as an expected range of zero to $100/MWh.

The third perspective taken in current metrics is to assess the effect of offer caps on EIS Market prices. The SPP Offer Cap is imposed only when there is transmission congestion. The SPP Cap varies by resource and by location – it is lower (tighter) in areas with more transmission congestion. Moreover, since it reflects the cost of entering the EIS Market by building and operating a new combustion turbine power plant, it also is a measure of the competitive price level that we would not want to be exceeded in the EIS Market. Given this, we look at how often a price offer is accepted near the SPP Cap. If this is common, then the SPP Cap is holding prices down just like a lid on a pot of boiling water. In contrast, if price offers are seldom accepted near the SPP Cap, then we believe this indicates prices are comfortably below this one measure of a *competitive level* and, therefore, there is no evidence of market power concerns. The bottom-line is that price offers were almost never accepted near the SPP Cap. Over the first seven months of EIS Market operation, such offers were accepted in a negligible portion of the time – less than two hundredths of one percent of the resource intervals.

Similarly, the FERC imposed a separate offer cap that applies in all times for all resources. The FERC Cap was $400/MWh in the first three months of EIS Market operation and has been $1,000/MWh thereafter. Again, price offers were accepted near the FERC Cap in a negligible portion of the time – less than three hundredths of one percent of the resource intervals.

Market Participation

The Offer Caps mentioned above are meant to mitigate what the FERC terms *economic withholding* which, is submitting an inappropriately high offer price that drives market prices above the competitive level. Offer Caps to mitigate economic withholding are the most explicit market power mitigation tool for the EIS Market.

The FERC uses the term *physical withholding* to reflect an attempt to drive prices above a competitive level by not bidding some resources at all. Explicit mitigation against physical withholding in the EIS Market has not been designed because full participation in the EIS Market is voluntary. That is, Market Participants can decide for themselves (a) to self-dispatch their resources (their power plants) or (b) to participate fully by making their resources available for SPP to dispatch in the EIS Market.

Still, the Market Monitor measures market participation in three ways. The first is to determine the percentage of resources that are offered for dispatch in the EIS Market. In the first seven months, participation was consistently at a robust level; on average, 80% of capacity was made available for dispatch in the EIS Market.

The second measure of market participation is what portion of the capacity of a resource was made available for dispatch. Most power plants have a minimum level of operation that must be maintained (akin to a car sitting at idle) and some have a maximum that falls short of the full capacity of the resource (perhaps to reserve capacity to meet unexpected customer needs). For example, say a 100 MW resource is made available to the market with a minimum of 20 MW and a maximum of 70 MW (to leave 30 MW for reserves). In this example, then the Market Participant has made 50 MW or 50% of the capacity available to the EIS Market. In reality, over the first seven months of EIS Market operation the average portion of available capacity made available for dispatch (the average *dispatchable range*) was 48%. This is a reasonable level of dispatchable range.

The third measure of market participation indicates how fast the resource can be dispatched up and down within its dispatchable range. Of the three measures, ramp rate is the only one that indicates any concern about participation in the EIS Market. While ramp rates have improved a bit, the MMU has been and will continue to work with Market Participants to increase the offered ramp rates to assure more responsive dispatch.

Measures of Competitiveness

The results of measuring market participation also can be used to develop traditional, structural measures of the potential for market power concern. Three traditional measures are: the number of market participants, the market shares of winning Market Participants, and an antitrust measure called the Herfindahl-Hirschman Index (HHI) which is calculated as the sum of the squares of market shares.[3]

[3] For example, if a market had ten suppliers, each with a 10% market share, the HHI would be 1,000.

A high number of Market Participants indicates a competitive market because it (a) leads to aggressive bidding and (b) makes the success of collusive schemes less likely. The EIS Market has 21 Market Participants, which is a robust number of competitors.

A high number of Market Participants with smaller market shares also indicates competitiveness. For example, when judging when to grant a supplier the right to charge market-based (as opposed to cost-based) rates, the FERC uses a market share under 20% to support a rebuttable presumption that a supplier does not have the ability to exercise market power and, therefore, should be granted market-based rate authority. Over the first seven months of EIS Market operation, no Market Participant had a market share at or above 20%. Again, this is another indicator that the EIS Market is a workably competitive market.

A low HHI also indicates competitiveness. For example, the FERC and the U.S. Department of Justice use the same ranges of HHIs to judge the competitive effect of mergers and acquisitions: an HHI at or below 1,000 is something of a safe harbor, an HHI from 1,000 to 1,800 indicates moderate market concentration, and an HHI above 1,800 indicates high concentration. The FERC also uses a higher HHI threshold of 2,500 when judging whether to grant a competitor the right to charge market-based (as opposed to cost-based) rates. During the first seven months of operation, the HHI was 1,070 as measured by winning market shares of sales in the EIS Market; this HHI is just a small amount above the safe harbor level of 1,000. Alternatively, the HHI is 1,414 when measured by the shares of capacity made available to the EIS Market at the peak hour of the seven-month period. The HHIs indicate a reasonably competitive market.

Transmission Congestion

Transmission congestion may lead to market power concerns because it narrows the geographic range of competition and, thereby, the number of competitors. As shown consistently in the Monthly Reports on the EIS Market, transmission congestion is pervasive in the EIS Market. What we did herein was to use the seven months of operation to reveal the transmission facilities (flowgates) with the most congestion. Specifically we identified the top fifteen flowgates in terms of the portion of time congestion was seen on flowgates. (A flowgate is one or more transmission facilities that are monitored by SPP.)

The best long-term mitigation for possible market power concerns related to transmission congestion is to build more transmission and generation to lessen congestion in these areas. With the EIS Market in place, transmission planning has a new indicator of the value of new transmission investments; that is, since congestion increases EIS Market prices, the value of new investment might be measured by the potential to lower those prices. For this reason, SPP should want new investment to be targeted to the most congested flowgates. We took a first look at this and found that planned transmission investments do indeed seem to target the most congested flowgates in general although further study is needed. We recommend that matching up transmission investment to transmission congestion deserves more attention and that new monitoring and metrics should be developed to reveal whether the match has been achieved.

Special Topics

Over- and Under-Scheduling

During the design of the EIS Market, Market Participants were concerned that some suppliers may be able to take advantage of differences in prices at points of generation as compared to points of load. That is, some suppliers could *arbitrage* these differences in prices to inappropriately increase revenue. If prices at generation were above those at load, a Market Participant may inappropriately increase revenue by *under-scheduling* its load and resources. If the opposite price relationship was seen, a Market Participant might inappropriately increase its revenue from the EIS Market by *over-scheduling* load and resources.

For this reason, the EIS Market design includes software which identifies these opportunities for price arbitrage and, if extra revenue is earned, it is automatically disgorged. In the first seven months of EIS Market operation, 13 of the 21 Market Participants had some revenue disgorged. The total disgorgement was about $3.4 million, which is about 0.7% of the total EIS Market sales revenue over those seven months. About 1.9% of total load was involved in disgorgement. For most of the Market Participants the portion of their total MWh involved was well under 5%. For one Market Participant, however, the portion of their MWh involved for disgorgement was 22.5%. The MMU has had discussions with this Market Participant to fully understand the situation, and determined that the Market Participant's actions are appropriate in their circumstances.

Strategic Withholding and Uneconomic Overproduction

As with over- and under-scheduling, there were also concerns about additional practices that some Market Participants might use to take advantage of the EIS market. These included Strategic Withholding and Uneconomic Overproduction. The FERC required that the MMU monitor for these behaviors.[4]

Strategic Withholding is the ability of a resource not covered by the Offer Cap to artificially raise prices. Uneconomic Overproduction is when a resource produces more power than is justified by economics or by reliability. These two practices might be paired together by a Market Participant; that is, the Market Participant would first use its self-scheduled plants to overproduce on the exporting side of a flowgate which causes congestion. This then requires plants on the importing side of the flowgate to increase production. A Market Participant's plants on the importing side, which were not covered by the Offer Cap, would then be able to force the price on the importing side to above the Offer Cap, allowing all the Market Participant's resources on the importing side to receive this inflated price. That Market Participant could make a profit, even accounting

[4] *See* 114 FERC ¶ 61,289. *Order on Proposed Tariff Revisions* at P 174.

for any losses it suffered due to the Uneconomic Overproduction. The MMU is monitoring for Strategic Withholding and Uneconomic Overproduction and will report any incidents it sees to the FERC.

SUMMARY OF THE NEED FOR NEW OR ENHANCED METRICS OF THE MMU

In the previous section, based on a review of current metrics, we found that the first seven months of EIS Market operation gave no reason for significant market power concerns. If we had found reason for concern, we would have a more urgent need for new metrics – new diagnostic tools – to go deeper into the causes for the market power concerns so we could propose additional mitigation.

Although we found no urgent need, it is still worth considering the need for new or enhanced metrics for at least two reasons. First, the MMU now has hands-on experience with the EIS Market and is in a better position to know what diagnostics tools it needs. Second, the MMU should always be aware of and consider the array of FERC-approved metrics on mitigation measures used by other RTOs and ISOs.

As requested, our purpose here is to list and briefly explain possible new and enhanced metrics for the MMU's consideration over the next year. To come up with the list we (a) brainstormed with the MMU, (b) applied our own experience in monitoring, and (c) reviewed metrics used in other RTOs and ISOs including ERCOT, MISO, and PJM. Section III of this report provides the ideas for metrics that came out of these three sources. They are ordered under five topics – all used in Section II with one exception. For each metric there is provided a brief description of why it might be needed and how it might be measured. The following is a list of the ideas in each category.

Market Prices

1. Define and implement metrics to assess changes in market conditions that might explain changes in prices each month.

2. Define and implement a metric to identify the fuel type which sets the EIS Market prices (i.e. identify the fuel type at the margin).

3. Define and implement a metric to assess the impact of congestion on market prices.

Market Participation

1. Define and implement a metric to report transmission and generation outages.

Measures of Competitiveness

1. Define and implement a metric to calculate net revenue to indicate which, if any, type of new generation investment might be justified by current EIS Market prices.

2. Explore, but do not necessarily implement a metric to identify “pivotal” suppliers.

3. Explore, but do not necessarily implement a metric to compare EIS market prices to supplier marginal costs.

Transmission Congestion

1. Define and implement more metrics that make transmission congestion more transparent by tying it to specific corridors and flowgates, and by attempting to explain the business reasons for congestion in those corridors or those flowgates.

2. Define and implement additional utilization metrics for the existing transmission system.

3. Define and implement metrics which identify new transmission expansion investments and tie them to specific corridors and flowgates.

Metrics Deepened to Market Participant Level[5]

[5] The MMU has already and should continue to deepen some existing metrics to the Market Participant level.

SECTION II: ASSESSMENT OF THE EFFECTIVENESS OF THE PLAN AND MEASURES USING CURRENT METRICS SUCH AS THOSE INCLUDED IN THE MONTHLY AND QUARTERLY REPORTS

In this section, we provide an assessment of whether there is any indication of market power concerns in the SPP EIS Market using current metrics such as those included in the Monthly and Quarterly Reports. We analyze current metrics related to (a) the level of prices, (b) offers submitted by Market Participants, (c) participation in SPP's market, (d) competitiveness, (e) transmission congestion, and (f) other special topics.

MARKET PRICES

Market Power is defined as the ability to profitably raise prices above competitive levels, for a sustained period of time. Therefore, the most obvious area to monitor for signs of possible market power concerns is the level of prices. We look at price data to see (a) if SPP-wide prices are in-line with those seen in neighboring markets such as MISO and ERCOT and (b) if sub-regional or locational prices within the SPP footprint are in-line with each other.

Comparison to MISO and ERCOT

Comparing SPP-wide prices to those seen in neighboring, more mature markets, serves as the broadest check for possible market power concerns. Separate markets have many differences, such as generation mixes and weather patterns, so we do not expect SPP's prices to fully mirror MISO's and ERCOT's prices. However, we do expect them to be generally in-line with those seen in the neighboring markets. Table One, below, shows price statistics for SPP, MISO, and ERCOT for the seven-month period covered in this report.

Table One
Comparison of SPP-Wide, MISO-Wide,
and ERCOT-Wide Hourly Price Statistics for the Seven-Month Period

Region	Average Price	Max. Price	Min. Price	Median Price	Volatility	Average On-Peak Price	Average Off-Peak Price
SPP	$50.21	$386.16	($105.82)	$51.26	50%	$59.27	$42.11
MISO	$49.48	$249.52	($22.62)	$39.29	67%	$66.67	$34.10
ERCOT	$53.96	$1,500.00	($238.74)	$50.60	80%	$61.51	$47.23

Table One compares the simple average of SPP prices to the simple average of MISO and ERCOT prices. SPP's simple average price for the seven-month period is 6.9% below ERCOT's price and 1.5% above MISO's price. Therefore, at this broad level, SPP's prices appear to be in-line with ERCOT's and MISO's prices.[6]

[6] For SPP, we also calculated the load-weighted average price. This was $53.21, which is still lower than the ERCOT simple average.

We also want to draw attention to the comparison of prices for on-peak and off-peak periods. SPP's simple average on-peak price is 11% below that in MISO and 4% below that in ERCOT. Some think that on-peak periods are more likely to be subject to market power abuse so the fact that SPP prices are lower in these periods gives some comfort in this regard. In contrast, SPP's simple average price in off-peak periods is 23% above MISO; however, it is 11% below ERCOT. Both on-peak and off-peak differences may well reflect differences in the resource mix.

The average prices over the whole period can give an idea of what the SPP market looks like relative to its neighboring markets, but can mask possible differences in the SPP market across the months. Therefore, we also looked at month-by-month price data. Figure One, below, charts prices at the monthly level in SPP, MISO, and ERCOT. SPP's monthly average price increased as it went from spring to summer (as expected), but it remained in-line with its neighboring markets. For the most part, SPP's monthly prices fell between those of MISO and ERCOT. The largest monthly price difference occurred in March when SPP's simple average price was 17% below ERCOT's price; however, it was only 3% below MISO's price. August represented the only month in which SPP's price was the highest – it was 10% higher than the MISO price, but only 1.3% above the ERCOT price. Once again, we see that SPP prices were in-line with those in MISO and ERCOT on a monthly basis.

Figure One
Comparison of SPP-Wide, MISO-Wide,
and ERCOT-Wide Hourly Average Prices by Month

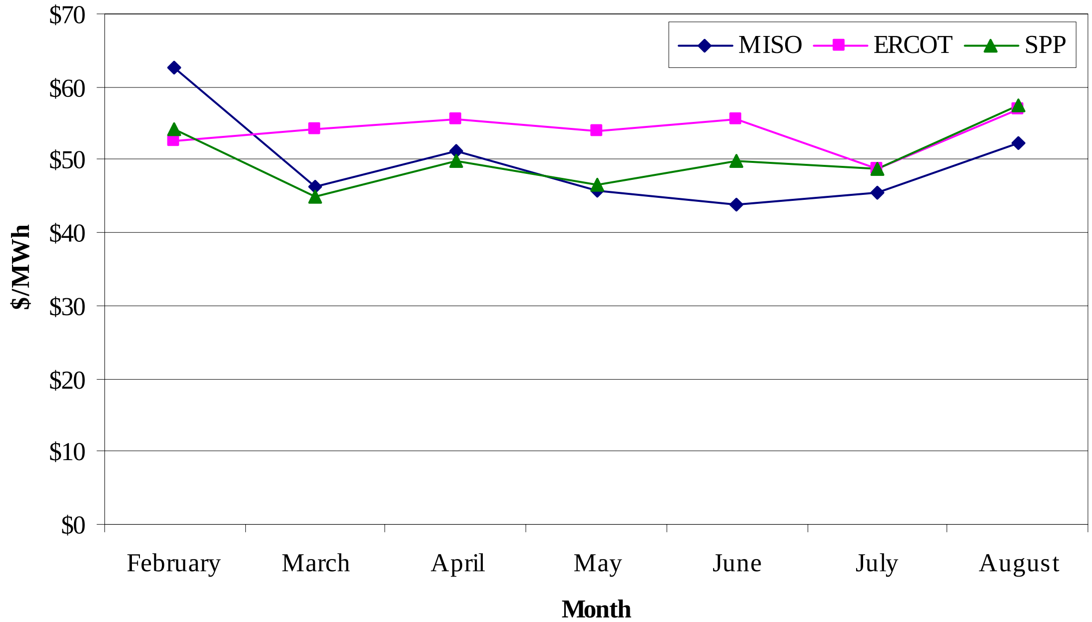
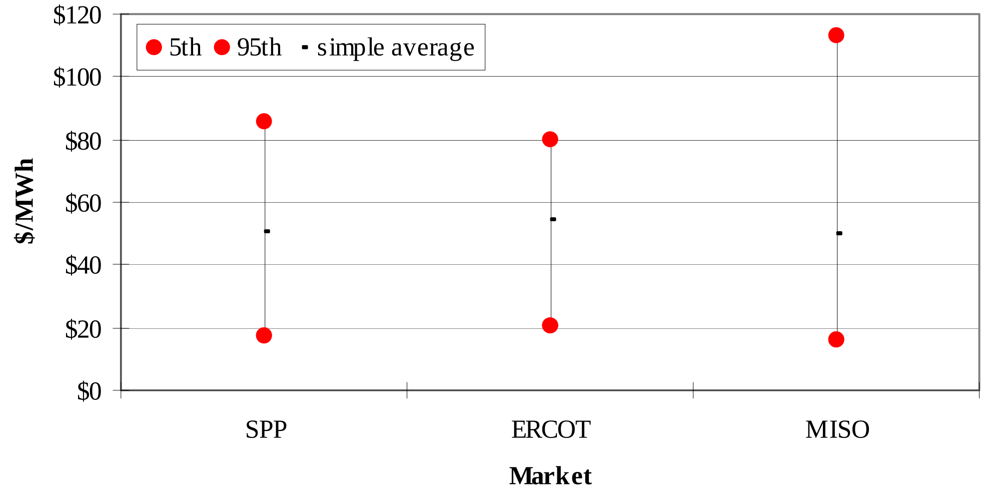


Figure Two, below, makes an even more granular comparison by showing the distribution of *hourly prices* for the three markets. The idea here is to see if the majority of the price points for each market are comparable to each other. We do this by looking at the hourly prices that fall between the 5th and 95th percentiles; that is, the lowest 5% of prices and the highest 5% of prices were excluded, leaving the middle 90%. The figure shows that there is significant overlap in prices. This again shows that SPP prices are comparable to market prices in mature, neighboring markets even at the hourly level.

Figure Two
SPP, ERCOT, and MISO Hourly Prices



Comparison Across Locations Within SPP

We are also concerned with regional or locational prices within the SPP footprint. As with comparisons to MISO and ERCOT, significant differences in prices across locations within the SPP footprint could be cause for concern. We first look at the level of prices for each of SPP's load settlement locations. As we did with the SPP-wide prices, we will progress from a broad view of prices to a more narrow view.

Figure Three, below, shows the simple average of hourly prices for each load settlement location for the seven-month period. All of the average load settlement location prices fall within 15% of the SPP-wide average. SPS has the highest price of all the settlement locations with an average price of $57.22/MWh. However, if you exclude the highest 1% of prices in SPS, its average price falls 11% to $51.09; this indicates that price spikes are driving the SPS average price higher.

Figure Three
Average 7-Month Prices (simple average)

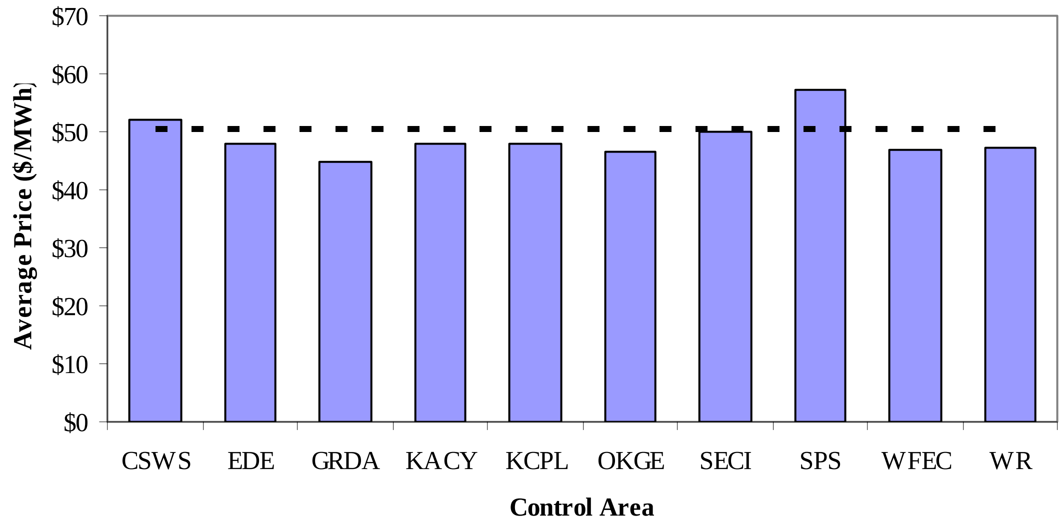


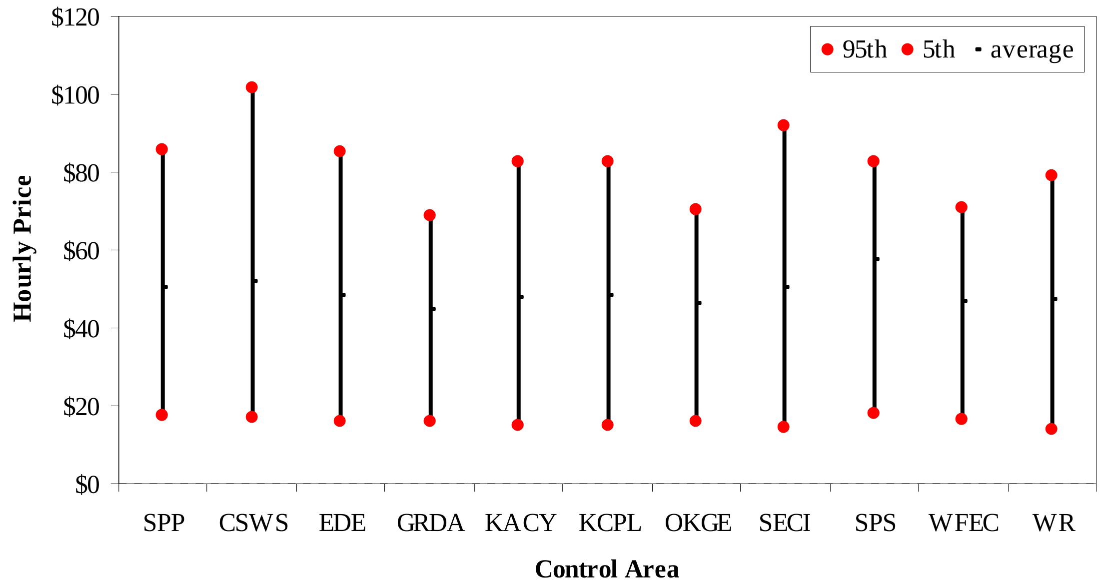
Table Two below displays the volatility of hourly prices, as measured by the coefficient of variation, for each load settlement location. (The coefficient of variation measures the average hourly difference in price as compared to the overall average price.) The volatilities, with the exception of SPS, range from a low of 40% in OKGE to a high of 70% in SECI. SPS's volatility is 148%, which varies significantly from the other settlement areas. However, if we again exclude the top 1% of prices, the volatility drops to 45%. The high volatility and the price spikes seen in SPS are most likely a result of the congestion that occurs in the SPS balancing authority (we discuss this in more detail later in the report).

Table Two
Volatility for Load Settlement Locations

SPP	CSWS	EDE	GRDA	KACY	KCPL	OKGE	SECI	SPS	WFEC	WR
50%	56%	53%	42%	62%	63%	40%	70%	148%	40%	49%

Figure Four, below, displays the *hourly price* distribution for each load settlement location. Once again, we do this by showing the hourly prices from the 5th percentile to the 95th percentile. The middle 90% of prices illustrates significant overlap in hourly prices across SPP's load settlement locations. Even SPS shows considerable overlap.

Figure Four
Price Range by Load Settlement Location



The most granular view of prices is at the interval level. Prices are calculated every five minutes at various locations across the SPP footprint, and are termed Locational Imbalance Prices (LIPs). Because these are the most granular price data, it is important to see how prevalent price extremes are in SPP. With this in mind, we took all of SPP's LIPs (for both load and generation settlement locations) for the seven-month period, and separated them into four categories: (i) less than $0/MWh, (ii) between $0/MWh and $100/MWh, (iii) between $100/MWh and $400/MWh, and (iv) above $400/MWh. Below, Table Three shows the percentage of these prices that fall into each bin. The $400/MWh price reflects the FERC's bid cap for the first three months of EIS Market operations.

Table Three
Flagged Interval Prices Beyond Thresholds

Month	Percent of Observations Less Than $0	Percent of Observations Between $0 and $100	Percent of Observations Between $100 and $400	Percent of Observations Greater Than $400
February	1.1%	94.0%	4.5%	0.3%
March	1.0%	97.2%	1.8%	0.1%
April	0.3%	98.6%	1.0%	0.2%
May	0.3%	98.6%	1.0%	0.1%
June	0.9%	95.8%	2.9%	0.4%
July	0.3%	97.9%	1.5%	0.2%
August	0.5%	94.9%	4.2%	0.3%
Total	0.6%	96.7%	2.4%	0.2%

We see that the vast majority (96.7%) of the prices were in the range of $0/MWh to $100/MWh, 2.4% were between $100/MWh and $400/MWh, and less than 1% was either above $400/MWh or below $0/MWh.

MARKET PARTICIPANT OFFERS

Locational Imbalance Prices in SPP are calculated using, among other things, Market Participant offer curves. Because these offers are a major driver of prices, there is a potential concern with market power through submission of higher than appropriate offer prices. The FERC refers to this as Economic Withholding. To mitigate this, SPP has in place two different FERC-approved offer caps. These caps do not put a cap on prices, but rather, limit how high of an offer a Market Participant can submit.

The offer cap that we term the "FERC Cap" is a hard offer cap. What we mean by this is it (a) is set at a constant level, (b) applies to all resources, and (c) applies at all times. The FERC Cap is considered to be a "safety net" against extreme cases of economic withholding. For the first three months of the EIS market, the FERC Cap was set at $400/MWh. Since May 2007, the FERC Cap has been increased to $1,000/MWh. The cap was set at a tighter level for the first three months because of the uncertainty surrounding the start of the market.

SPP's other offer cap is termed the "SPP Cap". Unlike the FERC Cap, the level of this cap (a) is resource specific and (b) varies depending upon market conditions. The SPP Cap is designed to balance mitigation and reliability; that is, it limits price spikes resulting from market power, but, at the same time, is set at a level high enough not to discourage new investment.

The following three characteristics of the SPP Cap illustrate how this is accomplished. First, the SPP Cap is levied only during times of congestion, because absent congestion the SPP Market appears to be workably competitive. Second, it is only imposed on those resources that have the potential to wield market power and on co-owned resources; that is, it applies only to resources with a Generator to Load Distribution Factor (GLDF) of negative 5% or larger (more negative) and other resources with negative GLDFs owned by that same company. Third, the SPP Cap is set at a level that will not discourage new investment. The SPP Cap reflects the total annual fixed and variable costs of a new peaking power plant with the fixed costs spread over the hours of congestion. Therefore, the more hours of congestion the tighter the cap becomes.

We assessed how much of an effect the offer caps are having on prices in the EIS Market. In other words, we asked whether these offer caps are, in effect, holding prices down much like a lid on a pot of boiling water. One indication of a significant effect would be if price offers that were being accepted (dispatched) are at or near the offer caps. Table Four shows that, in this sense, the effect of these caps has been negligible. The column entitled "Percent of Resource Intervals Dispatched with Offer Near FERC Cap" illustrates that offers were accepted near (within 5%) the FERC Cap in only 0.026% of all opportunities (all "resource intervals"). The table also shows that the effect of the SPP Cap has been negligible. The SPP Cap was imposed in 18.96% of resource intervals; however, offers were accepted near that cap in only 0.0146% of resource intervals.

Table Four
Effect of the FERC and SPP Offer Caps

Month	Percent of Resource Intervals Dispatched with Offer Near FERC Cap	Percent of Resource Intervals with SPP Cap Imposed	Percent of Resource Intervals with SPP Cap Imposed and Dispatched Near SPP Cap
February	0.1361%	13.83%	0.0005%
March	0.0423%	14.82%	0.0006%
April	0.0114%	11.32%	0.0000%
May	0.0000%	12.63%	0.0000%
June	0.0016%	23.56%	0.0317%
July	0.0001%	27.48%	0.0458%
August	0.0000%	28.20%	0.0219%
Total	0.0260%	18.96%	0.0146%

MARKET PARTICIPATION

Full participation in the SPP EIS market is voluntary. Market Participants can decide whether to self-dispatch their units or make them available for SPP dispatch in the EIS Market.[7] Given that the market is voluntary, explicit mitigation measures for physical withholding are not warranted. However, the Market Monitor still monitors the level of participation. The concern is that withholding participation could be used to increase prices – this is what the FERC terms physical withholding.

We take a look at participation in three different ways: (a) the percentage of capacity made available to the market, (b) the dispatchable range of available units, and (c) the ramp rates of available units.

As part of their resource plans, Market Participants designate their units as self-dispatched or available for EIS Market dispatch. For self-dispatched resources SPP assumes those units will be at their scheduled level. For available resources, SPP determines the level of operation through security constrained economic dispatch. The first check for the level of participation in the EIS Market is what percentage of capacity is being made available. To calculate this we divide the available capacity by the sum of available and self-dispatched capacity. As seen below in Table Five, the level of SPP-wide availability, for each month, has been consistently around 80%. This also shows that as load increased during the summer months, so did the amount of available capacity. Consistent participation at 80% is a very robust level of participation and shows that physical withholding has not been a concern.

[7] Note that a resource can also be designated manual, supplemental, or unavailable. For the purposes of this section, we focus on just those resources that are available or self-dispatched.

Table Five
Percent of Total Capacity Made Available
to the EIS Market by Month

Month	Available Capacity	Available and Self-Dispatch Capacity	SPP-Wide Availability
February	17,944	23,443	77%
March	16,164	20,786	78%
April	17,002	21,154	80%
May	17,884	22,696	79%
June	21,278	26,156	81%
July	23,153	28,163	82%
August	24,225	29,859	81%
Average*	19,694	24,634	80%

* Average is weighted by the number of days in each month

There are two ways a resource can limit its participation in the market, even when it has been made available to the market. First, a resource can limit its dispatchable range; that is, the portion of the capacity that can be moved up and down as customer need varies. As seen below, the dispatchable range has been consistently equal to about 48% of available capacity. The low over the seven-month period was 46% in May, and the high over the period was 50% in February. We see this as a robust level of dispatchable range.

Table Six
Dispatchable Range of Capacity Made
Available to the EIS Market by Month

Month	Available Capacity	Dispatchable Capacity	Percent Dispatchable
February	17,944	8,924	50%
March	16,164	7,622	47%
April	17,002	7,965	47%
May	17,884	8,242	46%
June	21,278	10,031	47%
July	23,153	11,119	48%
August	24,225	11,777	49%
Average*	19,694	9,393	48%

* Average is weighted by the number of days in each month

The second way a participant could limit the level of participation of one of its available units would be to provide a low ramp rate. The ramp rate dictates how fast a power plant can be moved from one level of operation to the next. Ramp rates are provided as part of a Market Participant's resource plan, and are provided in MW per minute. At the broadest level, we are concerned whether enough ramp is sufficient to meet changes in need across the SPP system. One way to determine this is to look at the number of ramp rate violations each month. A ramp rate violation can occur when there is not enough ramp provided by available resources to rebalance generation and load. As seen in Table Seven, the number of ramp rate violations has fallen each month since February. In August, there was a ramp rate violation in only 0.44% of intervals. Therefore, in this sense the ramp rates being provided appear adequate. However, in the Table below, we see that the average ramp rate provided by available resources is approximately 3 MW/minute. This level seems low, and is a concern of the Market Monitor. Further, in some cases the Market Monitor has noticed that some self-dispatched resources are not providing enough ramp to achieve changes in the level of generation the Market Participant itself has planned (i.e., scheduled). Such behavior is putting an additional burden on the EIS Market. The MMU has written letters to Market Participants requesting that they provide reasonable ramp rates and schedules that reflect the accurate capabilities of their units.

Table Seven
Ramp Rates Violations and Average Ramp Rate of
Capacity Made Available to the EIS Market by Month

Month	Market Ramp Rate Violation Intervals	Percent of Intervals with Ramp Rate Violation	Average Ramp Rate Offered (MW per Minute)
February	105	1.30%	2.51
March	97	1.09%	2.63
April	81	0.94%	2.96
May	80	0.90%	3.70
June	71	0.82%	3.04
July	63	0.71%	3.01
August	39	0.44%	2.88
Average	76	0.88%	2.97

* Average is weighted by the number of days in each month

MEASURES OF COMPETITIVENESS

We also assess the competitiveness of the EIS Market with traditional structural measures. For example, we assess the market shares in the EIS Market. A standard for judging market share comes from a FERC standard for granting the right for a supplier to sell at market-based prices (as opposed to regulated cost-based rates.) In one of two FERC threshold tests for granting the right to sell at market-based prices, the FERC asks that the supplier have no more than a 20% share of the market. If the market share is 20% or less, it is presumed the supplier cannot exercise market power. If the market share exceeds 20%, the supplier can conduct an additional test or point to mitigation for market power, such as the mitigation measures and monitoring of SPP's MMU; that is, the 20% is not a hard and fast limit to market-based rate authority. We view market shares in two ways: (a) market shares of EIS Market sales and (b) market shares of capacity made available to the market. By looking at market shares of EIS Market sales we are able to see if any participants have a large share of what is actually sold in the market. Alternatively, we look at market shares of capacity made available to see whether any participants have a large portion of the capacity made available for SPP dispatch.

The following table shows, by anonymous Market Participant, market shares of EIS Market sales for each month of the seven-month period. No Market Participant has a market share greater than 20% for the seven-month period. Further, no participant had a share of greater than 20% in any month except June when one participant had a share of 25.4%. Overall, this table indicates by this metric that the EIS Market is competitive.

Table Eight
Shares of EIS Market Sales for
all Market Participants (anonymously ranked)

Market Participant	Market Share of Sales							
	February	March	April	May	June	July	August	Total
1	16.4%	14.0%	14.8%	18.8%	25.4%	17.3%	12.0%	17.0%
2	10.7%	17.1%	14.2%	15.5%	17.3%	12.3%	14.6%	14.6%
3	17.0%	15.7%	12.1%	12.4%	11.7%	13.3%	11.2%	13.1%
4	19.1%	15.6%	16.5%	14.8%	10.6%	7.4%	10.7%	12.9%
5	7.0%	8.2%	9.7%	1.7%	4.8%	14.6%	18.6%	10.0%
6	3.9%	5.9%	6.2%	8.5%	7.6%	8.3%	8.0%	7.1%
7	0.9%	1.6%	2.5%	7.7%	5.8%	10.3%	9.7%	6.1%
8	7.8%	5.4%	7.0%	2.9%	3.0%	2.3%	2.5%	4.1%
9	5.7%	2.9%	3.4%	4.4%	3.7%	2.9%	2.9%	3.6%
10	3.4%	2.4%	2.4%	2.0%	2.1%	2.1%	2.5%	2.4%
11	1.6%	2.6%	1.8%	1.7%	1.5%	1.6%	1.2%	1.7%
12	1.6%	1.7%	3.0%	3.4%	1.2%	0.9%	0.9%	1.7%
13	1.7%	1.9%	1.4%	0.8%	1.1%	1.2%	1.7%	1.4%
14	0.7%	1.7%	1.2%	1.3%	0.9%	1.1%	1.0%	1.1%
15	1.0%	0.9%	1.2%	1.4%	1.1%	0.9%	0.7%	1.0%
16	0.3%	0.2%	1.6%	1.4%	0.7%	2.0%	0.5%	1.0%
17	0.3%	1.0%	0.4%	0.3%	0.3%	0.9%	0.8%	0.6%
18	0.7%	0.7%	0.3%	0.4%	0.5%	0.4%	0.4%	0.5%
19	0.4%	0.4%	0.4%	0.6%	0.8%	0.4%	0.2%	0.4%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

HHI	1,220	1,145	1,064	1,154	1,346	1,097	1,127	1,070

The Herfindahl-Hirschman Index (HHI) is a measure of competitiveness closely related to market shares. Again, some background on the HHI standard is useful. The U.S. Department of Justice has a three-part standard for HHIs when judging the competitive effect of mergers and acquisitions. An HHI at or under 1,000 is a safe harbor of sorts because the market is said to be unconcentrated. If, after a merger or acquisition, the HHI is at or below 1,000, it is generally thought that there is no competitive harm from the merger or acquisition; that is, the merger or acquisition does not make the exercise of market power more likely. An HHI between 1,000 and 1,800 is said to indicate moderate concentration. An HHI over 1,800 is said to indicate a highly concentrated market. The FERC uses these same standards when it assesses mergers and acquisitions. However, for market-based rate authority, the FERC uses a threshold of 2,500 for the HHI in one of its standards.

The HHI, in the table above, ranged from 1,064 in April to 1,346 in June. The HHI for the seven-month period is 1,070 – this is almost below the safe harbor level of 1,000. Again, this metric indicates the EIS Market is competitive.

An alternative way to look at market shares is to look at percentage shares of capacity made available to the market. The following table shows the shares of capacity made available by participant *at the peak hour of each month*. Again, this is market concentration measured at the single peak hour. The peak for the seven-month period occurred in August. Participant 1 was the only participant with a share consistently above the 20% mark, with shares ranging from 24.8% in July to 27.8% in March. HHI statistics are higher here than the HHIs based on actual EIS Market sales, ranging from a low of 1,352 in July to a high of 1,650 in March. The HHI for the seven-month peak is 1,414. All of these HHI statistics fall within the moderately concentrated range.[8]

[8] By no means do we want this to be interpreted that, if a Market Participant has a large resource base, it is a bad thing to offer to the EIS Market. The opposite is more likely to be true. Withholding resources might raise market power concerns for that large Market Participant.

Table Nine
Shares of Capacity Made Available During the Peak Hour
of the Month for all Market Participants (anonymously ranked)

Market Participant	February	March	April	May	June	July	August	Period*
1	26.7%	27.8%	26.9%	25.3%	26.0%	24.8%	25.5%	25.5%
2	11.6%	12.4%	16.2%	15.5%	16.2%	15.2%	17.1%	17.1%
3	21.2%	20.3%	15.2%	15.1%	15.4%	15.3%	16.0%	16.0%
4	12.4%	15.4%	12.7%	12.6%	13.2%	11.4%	9.3%	9.3%
5	4.7%	5.8%	8.4%	8.2%	5.5%	8.4%	7.7%	7.7%
6	2.3%	2.5%	4.6%	3.7%	2.8%	3.9%	4.1%	4.1%
7	2.5%	3.1%	2.6%	4.5%	4.3%	3.6%	3.6%	3.6%
8	3.9%	1.5%	2.0%	3.4%	3.8%	3.0%	3.5%	3.5%
9	2.2%	2.5%	0.0%	1.2%	1.8%	2.1%	2.8%	2.8%
10	3.3%	1.6%	2.4%	2.1%	2.5%	2.9%	2.6%	2.6%
11	3.5%	2.8%	2.6%	2.2%	3.1%	2.7%	2.6%	2.6%
12	0.0%	0.0%	2.3%	2.1%	0.0%	1.8%	1.7%	1.7%
13	1.3%	1.8%	1.7%	1.7%	1.4%	1.5%	1.2%	1.2%
14	3.0%	1.1%	1.3%	1.3%	2.9%	2.5%	1.0%	1.0%
15	1.1%	1.3%	1.2%	1.0%	1.0%	0.8%	0.8%	0.8%
16	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%
HHI	1,539	1,650	1,500	1,399	1,450	1,352	1,414	1,414

*Note: the peak for the seven month period occurred in August.

TRANSMISSION CONGESTION

Prices in the EIS Market diverge by location when there is transmission congestion, which occurs when a part of the transmission system reaches or exceeds its loading limit. Congestion essentially breaks the market into smaller submarkets with higher locational prices typically being seen within the constrained area. Transmission congestion increases the potential for market power concerns by narrowing the geographic scope of and the number of competitors in the submarket. The Market Monitor, therefore, monitors congestion on the transmission system to determine where congestion is most prevalent.

SPP manages congestion over flowgates, which are critical parts (elements) of the transmission system that represent a potential constraint to power flows. We now have seven months of data since the start of the EIS Market, so we can start to get a better understanding of which flowgates are consistently congested and which are only temporarily congested due to forced and planned outages. Table Ten, below, shows a month-by-month breakdown of congestion occurring on the top 15 most-congested flowgates. We measure congestion in the table by the number of five-minute dispatch intervals in which there is congestion on that flowgate.[9]

[9] The number of congested intervals for each flowgate includes the sum of binding and violated intervals. Binding intervals occur when the flowgate is at its loading limit and violated intervals occur when the flowgate exceeds its loading limit.

While we are interested in seeing which flowgates had the most intervals of congestion over the period, we are also interested in knowing which of these flowgates are experiencing consistent congestion each month. For example, the SPP to SPS Ties and SPS North–South flowgates not only rank as the top two congested flowgates, but they also experienced some congestion in every month of the period. The SPP to SPS Ties, alone, were congested in 18% of the intervals in the period. Another flowgate experiencing regular congestion was Flint Creek to Tontitown; this flowgate was congested in all of the months except for April.

Table Ten
Top 15 Congested Flowgates by Month

Flowgate Name	Corridor / Load Center	February	March	April	May	June	July	August	Total
SPP to SPS Ties	SPS	1,812	418	1,343	801	2,445	2,149	1,854	10,822
SPS North-South	SPS	459	694	1,596	312	692	928	883	5,564
Jeffrey to Summit*	Kansas East - West					5,213			5,213
Lone Oak to Sardis	Texas - Oklahoma East		3,046	415				4	3,465
SW Shreveport Transformer	Other						305	1,545	1,850
S. Philips to W. McPherson	Kansas East - West		339		8	58	1,339	94	1,838
Flint Creek to Tontitown	Arkansas West - East	824	125		26	438	8	143	1,564
Creswell to Newkirk / Kildare	Wichita - Oklahoma City	7	37	58	70	736	381	11	1,300
Kelly to Seneca	Other						455	735	1,190
Gentleman to Red Willow	Outside of SPP					40	405	585	1,030
S. Coffeyville to Dearing	Tulsa - Kansas City	9			41	240	89	470	849
Stilwell to Peculiar*	Kansas City	705	110						815
Judson Large to Greensburg	Other	211	11	70	17	53	10	432	804
Flint Creek to Tontitown*	Arkansas West - East	670			92	3			765
Flint Creek To Gentry	Arkansas West - East					13		740	753

* Indicates temporary flowgates.

The map below shows the geographical location of some of the most congested flowgates within the SPP Market.[10] The ovals represent important transmission corridors with notable cities and towns within the corridor denoted with blue circles. The flowgates are designated by lines with red bullet points at each end.

[10] Note that Gentleman to Red Willow is located outside of SPP, and thus is not shown on the graph.

Figure Five
Transmission Congestion Map Summary
by Flowgate for the Period

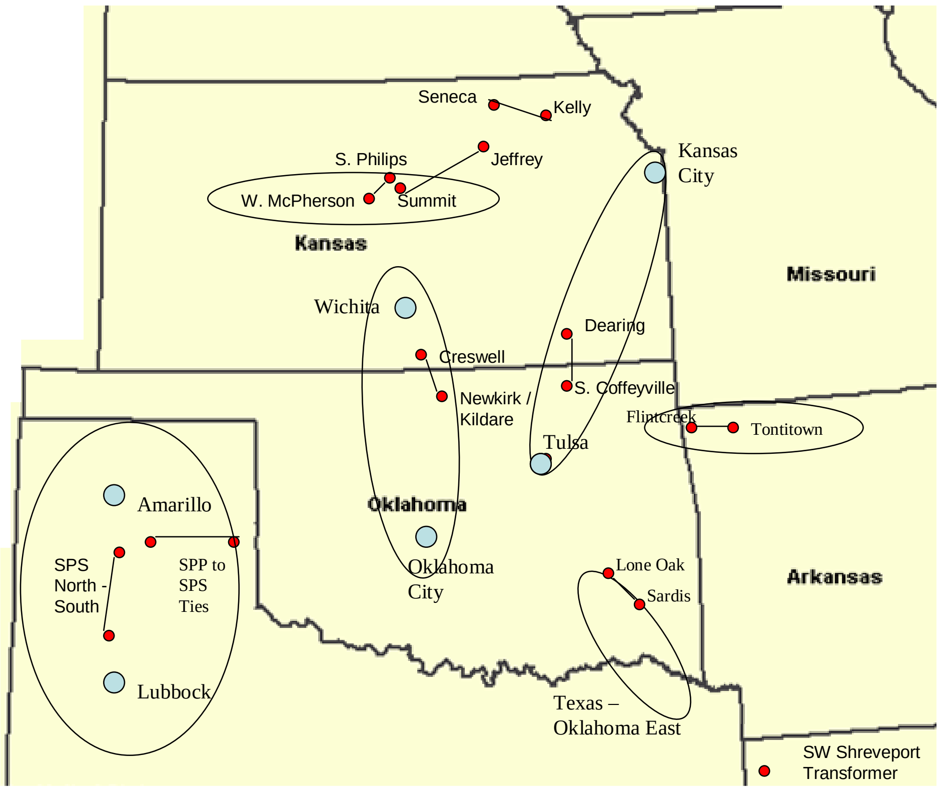
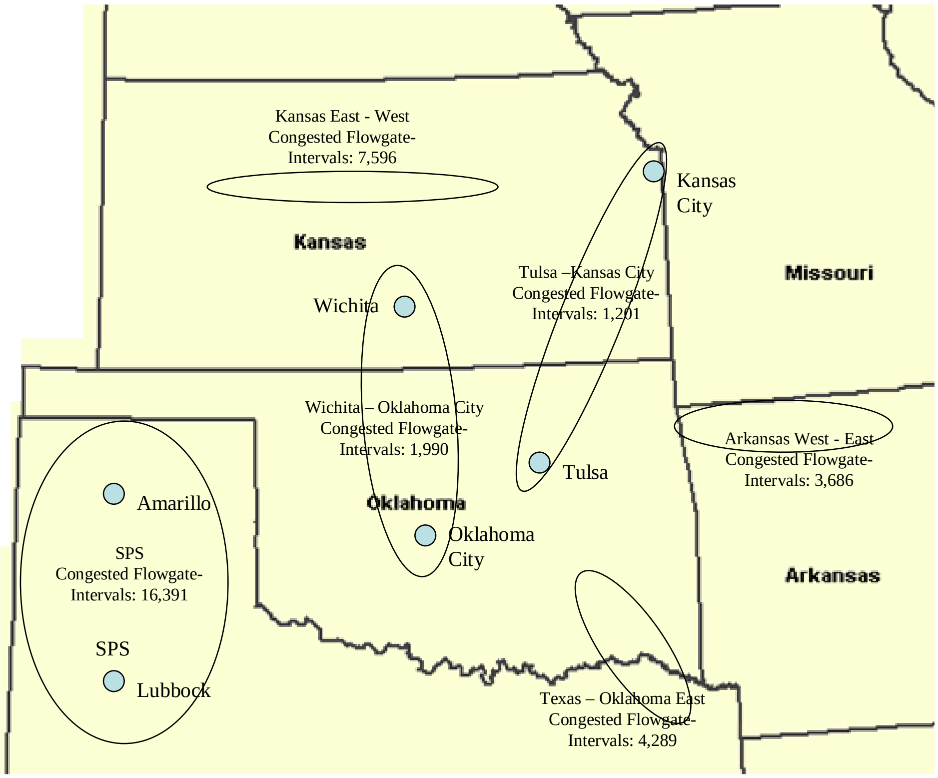


Figure Six allows us to see which transmission corridors are the most congested. It records the total number of congested intervals of all flowgates (not just the top flowgates) located in each corridor. Therefore, if two flowgates within one corridor are congested during the same interval, it is counted as two intervals of congestion. For this reason, our metric is termed flowgate-intervals. We chose to double count coincident intervals of congestion because we believe that accounting for congestion in this way best reflects the need for new investment.

Figure Six
Transmission Congestion Map Summary
by Transmission Corridor for the Period



We see, once again, that the SPS area is by far the most congested with 16,391 congested flowgate-intervals. Given the current transmission system, the SPS area can become essentially an island within SPP. Because of this, the flowgates bringing power into this area from SPP are at their limits on a regular basis. This congestion is also most likely the cause for SPS having the highest average price of all load settlement areas, and the highest volatility. Ramp rates are thought to be a cause of some of these issues.

The Kansas East–West Corridor and the Texas–Oklahoma East Corridor have experienced 7,596 and 4,289 congested flowgate-intervals, respectively. However, the majority of this congestion can be explained by outages causing heavy congestion in one month on one flowgate. The Jeffrey to Summit Temporary flowgate was heavily congested in June – this accounted for 69% of all the congestion seen in the Kansas East–West corridor for the period. Similarly, the Lone Oak to Sardis flowgate was heavily congested during the month of March – this accounted for 71% of the congestion in the Texas–Oklahoma East corridor for the period.

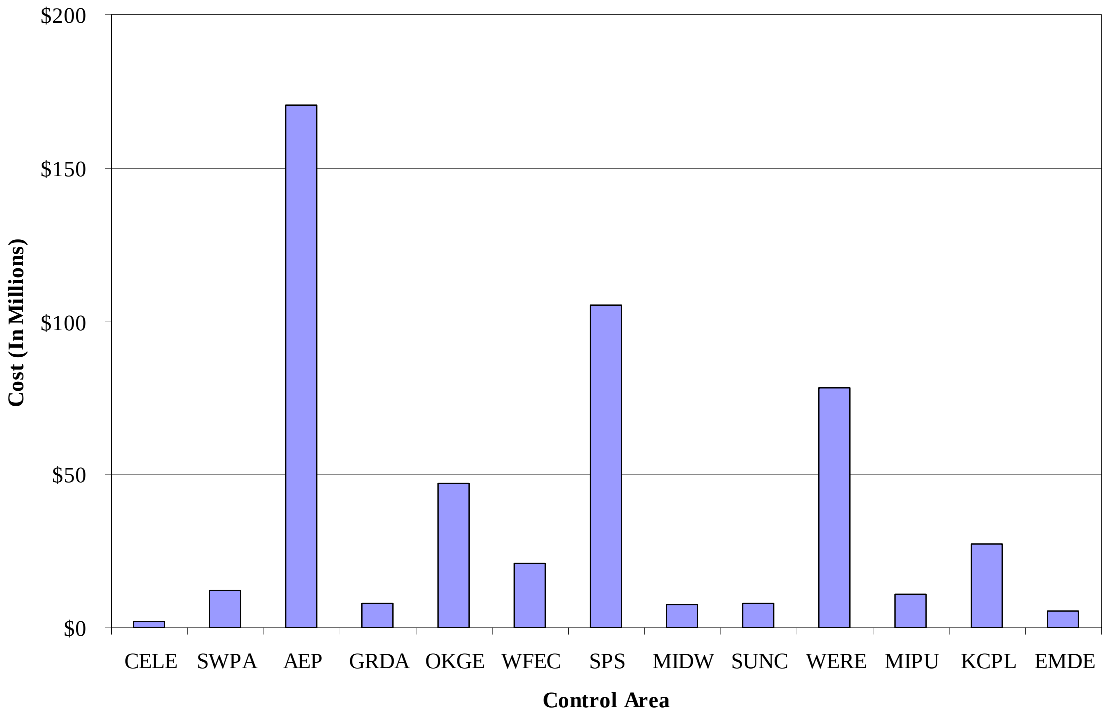
The next most congested area is the Arkansas West–East corridor. This area experienced congestion in each month. It also contained 3 of the top 15 flowgates seen previously in Table Ten. These were Flint Creek to Tontitown, a temporary flowgate from Flint Creek to Tontitown, and Flint Creek to Gentry. Moreover, of the 3,686 congested flowgate-intervals in this corridor, 2,440 reflected violated constraints rather than just binding constraints.[11] In fact, the Arkansas West–East corridor accounted for approximately one-third of all flowgate violations in SPP for the seven month period. Violations of flowgate limits are typically the cause of extreme prices in SPP.

The most effective long-run mitigation against possible market power concerns arising from transmission congestion, aside from SPP acting as an RTO, is transmission investment and generation investment. Transmission investment can increase the transmission capacity into constrained areas, and generation investment can increase the amount of generation capacity within constrained areas. Therefore, it is essential that plans for new investment address the problematic regions and, more specifically, the congested flowgates within the region.

To start, we looked at the planned transmission projects for 2007 and 2008 listed in the Transmission Expansion Plan. The following Table shows the dollars of planned investment for each control area for 2007 and 2008. The top three control areas with the most planned investment are AEP, SPS, and Westar (WERE). At a broad level, this seems to indicate that investment is targeting the right areas because these three control areas contain three of the most congested corridors; the SPS corridor is located in the SPS Control Area, the Arkansas West–East corridor is located in AEP's Control Area, and the Kansas East–West corridor is located in WERE's Control Area. These three Control Areas alone account for roughly 70% of the planned investment in 2007 and 2008.

[11] The number of congested intervals for each flowgate includes the sum of binding and violated intervals. Binding intervals occur when the flowgate is at its loading limit and violated intervals occur when the flowgate exceeds its loading limit.

Figure Seven
Tentative Cost Allocation of Transmission Expansion
Planned for 2007 and 2008 by Control Area



We also took a look at some of the major transmission projects within these three Control Areas to see if they address the most heavily congested flowgates. Large projects planned for 2007 and 2008 in the Northwest Arkansas area include a new line between Chambers Springs and Tontitown, a new line between Siloam Springs and Chamber Springs, and upgrades and other work at both Tontitown and Chamber Springs. These projects total $29.3 million of investment, and will most likely help alleviate some congestion in the Arkansas West–East corridor. In addition, the MMU informed us that there has also been some generation investment in the Northwest Arkansas area that is aimed at lowering the level of congestion on the flowgates bringing power into this area.

The Westar control area has plans to build a 40 mile 345 kV transmission line from Wichita to a new substation in Reno County and a new step down transformer at a new substation in Reno County, which should help flows in the Kansas East–West corridor. These projects are estimated to cost $42.8 million, which is more than half of Westar's estimated investment costs in the next two years. Finally, SPS has $105.2 million of planned investment in its control area; however, it is unclear how these projects will impact the SPS North–South and the SPP to SPS Ties.

The SPP Transmission Expansion Planning process is the tool used for regional expansion. SPP has completed its second Transmission Expansion Plan, and it has been effective in getting new transmission built and in upgrading existing transmission. Now that the EIS Market is up and running, it is essential that updated congestion data from the EIS Market is included in the Transmission Expansion Planning process going forward. This will help ensure that investment is being sited in the correct area, and more specifically, targets problematic flowgates. The Market Monitor should also analyze how new investment and outages are affecting transmission flow in SPP. We discuss a new metric in this regard in Section III.

SPECIAL TOPICS

Over/Under Scheduling

During the collaborative design phase of SPP's EIS Market, Market Participants raised the concern that participants would be able to profit from locational price differences by over- or under-scheduling their generation and load. These profits would result in an increased uplift (Revenue Neutrality Uplift) to the market. In order to mitigate these arbitrage opportunities, SPP developed a method for disgorging revenue accumulated from over- and under-scheduling, and the method was subsequently approved by the FERC.

To give a more detailed explanation of the concern and the mitigation measure in place, we first provide a simplified hypothetical example of how a participant could profit by under-scheduling, and then explain how SPP's mitigation tool nullifies the benefits gained by the participant. Assume a Market Participant schedules 30 MWh of generation and 30 MWh of load. However, its actual load and generation end up being 55 MWh – that is, the Market Participant under-scheduled. Assume further that the LIP at the load location is $20/MWh, and the LIP at the generation location is $40/MWh. In this instance, the participant has an imbalance at both generation and load. The participant *will be paid* $40/MWh for the 25 MWh of extra generation it produced over and above its schedule, but it *will pay* only $20/MWh for the additional 25 MWh of load over and above its schedule. Therefore, by under-scheduling, the Market Participant has profited by the number of MWh of imbalance times the difference in LIPs at generation and load [25 MWh of imbalance multiplied by ($40 minus $20)]. This yields $500 of profit for the Market Participant.

To mitigate this under-scheduling, SPP's computer software searches for parties that meet two criteria: (a) a party has actual load in excess of its scheduled load by the greater of 4% or 2 MW and (b) the party has a LIP at the location of its load which is *less than* the LIP at the location of its generation. When these two criteria are met, the settlement software automatically calculates the revenue that must be disgorged.

For over-scheduling, everything is simply reversed. First, the Market Participant schedules more load and generation than is actually needed, and secondly, the LIP at load is *higher than* the LIP at generation. This time the computer software searches for parties that (a) have load scheduled in excess of its actual load by the greater of 4% or 2 MW and (b) have a LIP at the location of its load which is *higher than* the LIP at the location of its generation. When these two criteria are met, the settlement software automatically calculates the revenue that must be disgorged.[12]

Table Eleven, below, shows the total disgorged revenue (over-scheduling payments plus under-scheduling payments) made in each month by Market Participant (anonymously listed).

Table Eleven
Dollars of Revenue Disgorged From Over- And Under-Scheduling by Market Participant

Market Participant	February	March	April	May	June	July	August	Total
1	$74,647	$45,188	$34,128	$10,094	$814,320	$127,635	$26,340	$1,132,352
2	$132,742	$387,769	$152,113	$58,606	$80,806	$11,223	$100,007	$923,266
3	$5,373	$1,084	$8,791	$44	$107,162	$110,171	$123,864	$356,489
4	$228,956	$3,665	$36	$33	$1,669	$12	$2,210	$236,581
5	$34,022	$5,299	$7,843	$5,409	$86,742	$34,908	$28,963	$203,186
6	$12,808	$6,252	$19,164	$3,734	$23,078	$22,199	$40,870	$128,105
7	$31,156	$1,133	$1,823	$51,083	$19,399	$2,728	$1,604	$108,926
8	$25,409	$22,374	$4,416	$10,389	$13,524	$3,854	$19,228	$99,194
9	$4,603	$32,218	$3,781	$5,572	$24,857	$3,924	$6,003	$80,958
10	$52,833	$4,419	$5,590	$1,963	$11,286	$549	$1,082	$77,722
11	$1,340	$992	$1,107	$579	$4,876	$1,195	$4,747	$14,836
12	$888	$470	$2,397	$2,052	$547	$792	$413	$7,559
13	$57	$20	$11	$34	$6	$6	$18	$152
14	$0	$0	$0	$0	$0	$0	$0	$0
15	$0	$0	$0	$0	$0	$0	$0	$0
16	$0	$0	$0	$0	$0	$0	$0	$0
17	$0	$0	$0	$0	$0	$0	$0	$0
18	$0	$0	$0	$0	$0	$0	$0	$0
19	$0	$0	$0	$0	$0	$0	$0	$0
20	$0	$0	$0	$0	$0	$0	$0	$0
21	$0	$0	$0	$0	$0	$0	$0	$0
Total	$604,835	$510,883	$241,202	$149,589	$1,188,272	$319,195	$355,349	$3,369,325

In the seven-month period from February to August, 13 out of the 21 Market Participants made some type of payment to SPP because they either over- or under-scheduled. The total over- and under-scheduling charges collected over the seven-month period was $3,369,325. Just to give this some perspective, note that the $3.4 million of charges is about 0.7% of total EIS sales revenue over the seven months.

Market Participant 1 had $1,132,352 disgorged over the seven-month period, which was the highest of all participants. The majority of this amount occurred in June and is related to the large Revenue Neutrality Uplift for the same period. Six of the eight participants that made no payments over the seven-month period simply did not have

[12] For a more detailed explanation of how the disgorgement tool works, please see the SPP Market Protocols v 6.0.

load. The remaining two made no payments because they never over- or under-scheduled their load by more than the greater of 4% or 2 MW during a time of price divergence.

We also quantified the extent to which Market Participants are over- or under-scheduling. The following Table shows, for each Market Participant, the MWh involved in disgorgement (for over- or under-scheduling) as a percentage of the MWh of total load for that Market Participant.

Table Twelve
MWh Involved in Disgorgement as Percentage
of Total Load by Market Participant

Market Participant*	February	March	April	May	June	July	August	Total
1	1.2%	1.6%	1.5%	2.2%	5.8%	1.0%	0.7%	1.9%
2	0.8%	1.0%	1.4%	0.6%	0.6%	0.4%	0.5%	0.7%
3	1.9%	3.1%	1.9%	0.6%	12.1%	37.1%	46.6%	22.5%
4	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.2%	0.1%
5	8.0%	5.1%	2.7%	3.0%	4.0%	2.8%	3.6%	4.2%
6	1.9%	2.2%	2.6%	3.0%	4.2%	3.3%	3.8%	3.0%
7	0.3%	0.3%	0.2%	0.5%	0.5%	0.2%	0.2%	0.3%
8	2.6%	2.7%	3.7%	2.5%	3.1%	2.3%	1.8%	2.6%
9	0.4%	2.6%	0.9%	1.4%	2.2%	1.2%	0.7%	1.3%
10	1.3%	1.4%	1.1%	1.2%	2.0%	1.2%	0.7%	1.3%
11	1.1%	1.7%	2.4%	1.4%	1.3%	0.8%	1.5%	1.4%
12	0.5%	0.4%	0.5%	1.1%	0.8%	0.9%	0.2%	0.6%
13	0.8%	2.7%	2.4%	2.4%	1.1%	1.2%	0.9%	1.6%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	1.2%	1.7%	1.5%	1.5%	2.6%	2.3%	2.5%	1.9%

* The Market Participant number seen here corresponds to the Market Participant number in Table 11.
For example, Market Participant 4 in this table represents the same entity as Market Participant 4 in Table 11.

Only Market Participant 3 had MWh involved in disgorgement in excess of 5% of total load. This participant saw a significant increase in the percent of disgorged MWh relative to its total load from 1.9% in February to 46.6% in August. The MMU has had discussions with this Market Participant to fully understand the situation.[13] That Market Participant had stopped scheduling its resources, and thereby, depends on the over- and under-scheduling regime to eliminate any undue profit.

[13] Note that Market Participant 3 had its percent of disgorged MWh relative to its load drop to 7.8% in September.

Strategic Withholding and Uneconomic Overproduction

SPP has also been monitoring for strategic withholding and uneconomic overproduction in the market. Uneconomic overproduction is when a resource causes congestion on the exporting side of a flowgate by producing power over and above what is economical or needed for reliability. Strategic withholding is when a resource on the importing side of a constrained flowgate is able to raise the LIP to a price above the offer cap. The concern is that a market participant that owns resources on the importing and exporting sides of the constraint could use uneconomic overproduction to create congestion over a flowgate, thus precluding resources on the exporting side of the constraint and forcing its resources on the importing side to increase production. This can lead to a resource that is not subjected to an offer cap being able to raise its price above the offer cap. This increase may also result in affiliated resources that are capped receiving the inflated price. This revenue from the high offer price would be used by a market participant to offset the cost of uneconomic overproduction, with the goal of having made money from these actions.

This concern was mentioned in Boston Pacific's testimony from January of 2006 and the FERC ordered that SPP take steps to monitor for this behavior.[14] This concern is not just unique to SPP. MISO, for example, is also concerned with what they term "uneconomic production", and in some instances there is a restriction on production on the exporting side of a constraint.[15]

SPP followed the Order by the Commission and in its Tariff outlined how the MMU will monitor for these behaviors. For uneconomic overproduction, SPP will look for specific cases where a self-dispatched resource(s) is (a) causing congestion on the exporting side of the constraint, (b) the production is uneconomical (i.e., the cost of production is greater than the LIP), and (c) the production is not justifiable because of either reliability or other operational concerns. For strategic withholding, SPP will watch for a marginal resource(s) available to the market, that is (a) not capped, (b) on the importing side of a constrained flowgate, and (c) where the LIP is greater than the offer cap.[16]

SPP has further detailed the actual steps they will take in the MMU's Confidential Uneconomic Over Production Resource Exclusion Procedures and the Market Monitoring Project MMR037- Strategic Withholding documents. When a Resource appears to be either uneconomically overproducing or strategically withholding, SPP will make every effort to first investigate the problem and cause, and then, if appropriate, will report it to the FERC as stated in the Tariff.

---

[14] *See* 114 FERC ¶ 61,289. *Order on Proposed Tariff Revisions* at P 174.
[15] *See* FERC Docket No. ER04-691-000. *Third Revised, First Volume of the Open Access Transmission and Energy Markets Tariff Pursuant to the Commissions February 24, 2003 Declaratory Order.* Prepared Direct Testimony of David B. Patton Ph.D. 3/31/04.
[16] *See Open Access Transmission Tariff For Service Offered by Southwest Power Pool. Fifth Revised Volume No. 1*. At Attachment AG. Section 4.6. Original Sheet No. 1115-1117.

SECTION III: ASSESSMENT OF THE NEED FOR NEW OR ENHANCED METRICS

In the previous section, based on a review of current metrics, we found that the first seven months of EIS Market operation gave no reason for significant market power concerns. If we had found reason for concern, we would have a more urgent need for new metrics – new diagnostic tools – to go deeper into the causes of the market power concerns so we could propose additional mitigation.

Although we found no urgent need, it is still worth considering the need for new or enhanced metrics for at least two reasons. First, the MMU now has hands-on experience with the EIS Market and is in a better position to know what diagnostics tools it needs. Second, the MMU should always be aware of and consider the array of FERC-approved metrics on mitigation measures used by other RTOs and ISOs.

As requested, our purpose here is to list and briefly explain possible new and enhanced metrics for the MMU's consideration over the next year. To come up with the list we (a) brainstormed with the MMU, (b) applied our own experience in monitoring, and (c) reviewed metrics used in other RTOs and ISOs including ERCOT, MISO, and PJM. What follows are the ideas for metrics that came out of these three sources. They are ordered under five topics – all used in the previous section with one exception. For each metric provided, there is a brief description of why it might be needed and how it might be measured; note that for some we suggest the MMU move forward with implementation while, with others, we suggest only that the MMU explore but not necessarily implement.

MARKET PRICES

As stated in Section II, market power is defined as the ability to raise prices, for a sustained period of time, above the level that would otherwise prevail in a competitive market. For this reason, it is essential to monitor and analyze the level of and changes in prices in the market. We suggest consideration of three metrics that will enhance the MMU's ability to effectively assess prices in SPP.

1. Changes in Market Conditions

First, we suggest at least a high-level assessment of changes in market conditions be implemented each month. These metrics would record changes or trends in (a) load, (b) fuel prices such as natural gas and coal[17], and (c) heating and cooling degree days, which serve as an indicator of the demand for electricity due to changes in weather. Natural gas and coal prices can be obtained from the U.S. Energy Information Administration (EIA), the Intercontinental Exchange (ICE), or other sources. We

[17] Note that MISO reports natural gas and coal prices in their Monthly Reports. *See* MISO September Monthly Report at page 20.

propose that heating and cooling degree days be recorded for specific locations in SPP such as Oklahoma City and Kansas City, two of SPP's load centers.

Each of these three factors can significantly influence supply and demand conditions within SPP. Therefore, when analyzing price levels it is always important to judge whether price levels are reasonable given market conditions. For example, if prices increased 15% from July to August, but load, the cost of natural gas and coal, and the number of heating degree days all increased as well, the 15% increase in price is most likely reflective of market conditions. Conversely, if prices increased by 15% from one month to the next, but load, fuel prices, and heating and cooling degree days all decreased, the price increase may need further study.

2. Fuel Type at the Margin

Second, we suggest a metric be implemented that identifies the fuel types setting prices in the EIS Market. SPP's prices are set by the price offer from the last resources needed to meet demand at a point in time. It is important to know what types of generators are actually setting prices in SPP, and whether any trends are developing. A further breakdown by on- and off-peak should also be considered. We would expect that natural gas resources are at the margin during peak periods, and lower cost resources such as coal are at the margin during off-peak periods. Identifying the fuel type at the margin is a common metric for RTOs and ISOs.

3. Congestion Cost

Third, we suggest that a metric be implemented that estimates the price effect of transmission congestion to distinguish it from the price effect of offer prices. Choosing the right method for the estimate will take some thought. One approach would be based on the two separate components of the LIPs. The first component is the System Marginal Price. The second component equals the Shadow Price times a Shift Factor; it is the second component that could be used as an estimate of the cost of congestion. Another approach would be to track offer prices at the margin and compare them to LIPs.

MARKET PARTICIPATION

Currently, the MMU monitors for economic withholding through the FERC and SPP Offer Caps, and physical withholding of generation by assessing participation statistics such as (a) percentage of resources available to the market, (b) percentage of available capacity that is dispatchable, and (c) the ramp rate of available resources. However, Market Participants can also effectively withhold generation and transmission through unwarranted outages. We, therefore, suggest a metric for outages.

1. Transmission and Generation Outages

We suggest the MMU implement a metric concerning generation and transmission outages. Planned outages occur when transmission and generating facilities undergo anticipated, scheduled maintenance. Forced outages occur when a generating unit or transmission element fails, causing an unanticipated outage. It is expected that there will be more planned outages during the shoulder months and less planned outages during the summer and winter months. Further, because forced outages are not planned, it is expected that these outages be spread out over time in a random manner. The concern is that a Market Participant would withhold transmission or generation during critical high-load time periods by (a) unnecessarily scheduling outages or (b) declaring a forced outage. These behaviors can cause prices to increase as well as congestion to occur on the transmission system. In addition, by withholding transmission capacity, a transmission owner could potentially preclude other participants from having access to the transmission system.

Although the MMU currently monitors specific outages across SPP, we suggest consideration of a metric that analyzes the pattern of outages in SPP. To do so, we suggest the MMU compare transmission and generation outages across the months of the year and during on- and off-peak times. Once again, it is expected that there will be more planned outages during the low load time periods and fewer planned outages during higher load periods. In addition, outages should be compared to load levels and as a percentage of capacity. Both MISO and PJM perform similar analysis in their monthly or state of the market reports.

MEASURES OF COMPETITIVENESS

As evidenced by the discussion in Section II above, the MMU already has several measures of competitiveness that it can review. Structural measures include the number of competitors, the market shares of winning bidders, and two different HHIs for the EIS Market. Also as explained in Section II, the SPP Offer Cap itself is a measure of competitiveness in the sense that it caps offers at a level representing the cost of new entry. Other RTOs and ISOs use additional measures and we illustrate the range with the following four examples.

1. Net Revenue Calculation

First, we suggest that a Net Revenue Metric be defined and implemented. Akin in some ways to the logic of the SPP Offer Cap, other RTOs and ISOs estimate whether market prices over the past year would be sufficient to cover the annualized cost of building a new power plant and, therefore, indicate that such an investment would be justified. Not only is investment in a new gas-fired peaking combustion turbine plant assessed – the type of plant reflected in the SPP Offer Cap – but also assessed are investments in gas-fired combined cycle plants, new pulverized coal plants and new nuclear plants.

This is termed a Net Revenue assessment because the calculation is meant to determine if market prices – such as hourly EIS Market prices – would be sufficient to cover fuel and other operating costs and, still, *net of those operating costs*, yield revenue sufficient to cover the fixed investment costs and fixed operating cost of a new power plant. Of course, as with any metric, the Net Revenue assessment has to be put in perspective. First, it reflects only one year – an investor would have to have evidence that he or she could cover the full annualized cost of a new plant over many years before he or she would move forward with an investment. Second, whether Net Revenue *should be expected* to justify a new investment will depend on market balance – we would expect it to be less than sufficient when there is excess power plant capacity and more than sufficient when there is a shortage. Third, fuel prices can provide an economic justification even if there is surplus capacity – for example, high gas prices might mean Net Revenue is sufficient to justify new wind, coal, and nuclear capacity. Fourth, it must be done over a full year – it cannot be done on only a monthly basis. Fifth, the cost of building and financing a new power plant is site specific and a real challenge to estimate; only ballpark estimates based on public information can be expected here.

If it can be put in perspective in these ways, the Net Revenue assessment is a common metric that can be published in the *State of the Market Report* for a calendar year or in a Quarterly Report using the most recent twelve months.

2. Pivotal Suppliers

Second, we suggest that the MMU explore, but not necessarily implement a metric based on the concept of a pivotal supplier. Several years ago the FERC sparked interest in using the notion of a *pivotal* supplier in market power analysis. One example of such an analysis is the Residual Demand Index (RDI) used by the ERCOT Independent Market Monitor (IMM). Another example is the Three Pivotal Supplier Test used by the PJM MMU.

Put simply, the RDI asks whether and when the largest power supplier in a market is essential to satisfy demand at a point in time. For example, say demand at a point in time was 100 MW and the power plant capacity offered to meet that demand by all suppliers as a group was 120 MW. If the largest supplier controlled 20 MW or less, then that supplier would not be needed to meet demand – even if the largest supplier withheld all of its 20 MW, the other 100 MW of supply would be sufficient to meet demand in full. However, if the largest supplier controlled more than 20 MW, at least some fraction of that supplier's capacity would be needed to meet the 100 MW of demand – in the parlance of this measure, that supplier would be *pivotal* or what we would term *essential*. A pivotal supplier might be in a position to exercise market power – it might be in a position to profitably increase prices.[18]

The Three Pivotal Supplier Test in PJM is based on the same concept of a pivotal or essential supplier as in ERCOT's RDI, but is more elaborate in its implementation.

[18] Note that the ERCOT IMM found that there was a pivotal supplier 21.2% of the time in 2006. From *2006 State of the Market Report for the ERCOT Wholesale Electricity Markets.* 8/2007. At page 123.

The Test results in a decision on whether to impose a cost-based offer cap in areas suffering transmission congestion.[19] There are three points that distinguish it from the less elaborate RDI.

- First, both demand and supply are measured in terms of impact on the constraint. That is, for example, a supplier's resource is included in the tally of total supply only to the extent it affects the constraint. (A 100-MW Resource with a 50% effect (a 50% Distribution Factor) would be counted as 50 MW (50% times 100 MW)).

- Second, a supplier's resource is included only to the extent it can offer a price reasonably close to the market price. (Currently, reasonable is defined as within 50%.)

- Third, rather than consider one supplier at a time, PJM determines whether three suppliers are *jointly pivotal*. If any supplier, in combination with the two largest suppliers, is jointly pivotal, then the offer cap applies to all three. (One might view the jointly pivotal notion as a presumption of collusion among the three suppliers.)

Again, we do not recommend implementation of a pivotal supplier test. However, given the use of such a metric elsewhere, the MMU should explore the notion. As in PJM, it can be used as an alternative to the current method of imposing the SPP offer cap some time in the future.

3. Prices and Marginal Cost

Third, we suggest that the MMU explore, but not necessarily implement a metric based on the comparison of market prices to supplier marginal cost. Metrics of this sort start with the notion that, under perfect competition, each supplier would offer its power supply at its incremental or "marginal" operating costs. A perfect competitor would do this because it has no control over market prices (no market power) so it will accept the market price as long as the market price covers the perfect competitor's marginal operating cost – anything above that will be profit to cover fixed costs of the supplier.

Generally, with such a metric, a production simulation model would be run to estimate the prices in the EIS Market if all suppliers had bid at marginal cost. These marginal cost-based prices would then be compared to actual EIS Market prices to determine if the actual prices were above the modeled prices. If actual prices are significantly above the estimated perfectly competitive prices, some might raise market power concerns.

The crucial data needed for this metric are estimates of the operating and startup cost for each power plant. In addition, to simulate the prices achieved over the past year,

[19] *PJM 2006 State of the Market Report*, 3/8/07. At Appendix J.

a production simulation model would have to capture the transmission system and other market conditions experienced in reality over that year. Both of these factors make it a challenging metric to produce as well as a challenge to defend. This is the primary reason we suggest that it only be explored at this point.

TRANSMISSION CONGESTION

1. More Transparent Transmission Information

We suggest metrics related to transmission be made as transparent as possible. Transmission systems are complex in both physical structure and method of operation. For this reason the topic of transmission is less transparent to policy makers and others who need to know, but are not transmission experts. The generation side of the business has become more transparent by making information on individual power plants readily available (name, location, size, fuel type, etc.) and by explaining in plain English operating methods (especially security constrained economic dispatch).

To make the transmission side of the business more transparent, information on transmission should be tied to specific facilities when possible – by major transmission corridors and flowgates. As illustrated in Section II, we and the MMU have begun to do that in all of our reports and that approach should be expanded. Another path to more transparency is to explain in plain English (as much as that can be done) why particular corridors or flowgates are congested. For example, is a corridor or flowgate congested because (a) it is a path for cheaper coal-fired power to displace higher-cost natural gas-fired power? (b) it is a path for imports into or exports out of the SPP footprint? or (c) it is picking up transmission flows due to a temporary outage of another flowgate?

Another good way to make transmission more transparent to policy makers is to address special topics of interest. For example, the FERC wanted to know the extent to which transmission was being resolved through the EIS Market rather than through TLRs. A special report was developed to address that topic and it showed that most congestion is now being resolved by the EIS Market. A special report on the transmission investment needed to accommodate new wind generation might be equally useful.

2. Transmission Utilization Metrics

We suggest the MMU implement a metric measuring transmission system utilization. One important policy question is whether SPP is getting the most out of the existing transmission system. Metrics that measure utilization should be presented. Some are already provided in annual reports – the number of accepted and rejected transmission requests is an example. Another useful metric would measure the extent to which the transmission system goes unused at various points in time; for example, what portion of transmission reservations remain unused in the sense that power flows are not scheduled?

3. Transmission Expansion Metrics

We suggest the MMU implement a metric related to the transmission system expansion. As noted in Section II, the ultimate remedy for transmission congestion is to build new transmission (or generation) facilities. For this reason, we suggest three related metrics. The first is to simply list the new transmission facilities that have come on line and the cost of each. The second is to tie this transmission investment to the corridors and flowgates that have substantial congestion. The third is to tie transmission investment to the corridors and flowgates that have the most expensive congestion problems (perhaps by indicating the cumulative shadow price for each congested flowgate.)

METRICS DEEPENED TO MARKET PARTICIPANT LEVEL

Given the MMU's experience monitoring the SPP Market, we understand it is working to deepen and refine some of the current metrics reported in the monthly and quarterly reports. For some of the metrics, the MMU is generating reports at the Market Participant level rather than just at the Balancing Authority level.

In addition, the MMU is analyzing load data at a more granular level. Again, rather than analyze load data at the Balancing Authority level, the MMU is analyzing load data at the Market Participant level. One main driver for this development is that the MMU would like to assess resource adequacy by Market Participant. This will allow the Market Monitor to see if Market Participants are providing enough resources to meet their load. Not all of this information will be public; however, it will serve to aide the MMU in their monitoring efforts.

SPP Southwest Power Pool

Helping our members work together to keep the lights on... today & in the future

---

SPP Southwest Power Pool

Markets & Operations
Policy Committee

- John Olsen – Chair
- Bill Dowling – Vice Chair

Overview

- **Action Items**
  - **SPP Transmission Expansion Plan (STEP)**
  - **STEP Notice to Construct (Appendix B)**
  - **AEP Waiver Request**
  - **EDE Waiver Request**
- **Informational Items (Only covered if questions)**
  - **BA Consolidation**
  - **GQTF**
  - **CBTF**
  - **ASITF**
  - **Sponsor Letter Process**

Action Items

SPP Transmission Expansion Plan

SPP Tariff Requirements

- SPP has facilitated coordinated planning for decades through model building, data reporting requirements and joint studies to address needs.
- SPP initiated a formal expansion planning process prior to FERC designation as an RTO.
- It is necessary to meet one of the requirements of an RTO.
- The SPP Transmission Expansion Plan (STEP) is required as outlined in Attachment O of the SPP OATT.
- 890 and 890A changes to Attachment O expanded transmission planning substantially to ensure that expansion planning is transparent and open to all affected stakeholders and to improve the efficiency and effectiveness of interregional, as well as local planning.
- The planning process is evolutionary such as extended the horizon to ten years and increased the depth of modeling. Stakeholders have become much more interested in the cost implications of the approved projects.

2007 SPP Transmission Expansion Plan Stakeholder Involvement

- November 8, 2006 - Scope Reviewed and Approved by TWG
- May 15, 2007 - Spring Planning Summit
  - Reviewed violations identified with analysis
  - Stakeholders requested to provide potential solutions
- August 15, 2007 - Fall Planning Summit 100 kV and above - public review of recommended plans
- August 16 through August 23, 2007 - Stakeholder Feedback on recommended plans
- October 8, 2007 - Fall Local Planning Web Conference 69kV and below - public review of recommended plans
- October 9 through October 17, 2007 - Stakeholder Feedback on recommended plans
- November 7, 2007 - SPP Staff provided overview of SPP Transmission Expansion Plan 2008-2017 Report to TWG
- December 4, 2007 - TWG reviewed the SPP Transmission Expansion Plan 2008-2017 Report and recommended changes
- December 10, 2007 - Public review of the SPP Transmission Expansion Plan 2008-2017 Report
- January 3, 2008 - TWG accepted the SPP Transmission Expansion Plan 2008-2017 Report, as modified

SPP Transmission Expansion Plan (STEP) Executive Summary

- $2.2B of transmission projects
- A comprehensive summary of all transmission projects planned or needed in the 2008 – 2017 planning horizon.
  - 96 Models vs. 15 Models – it parallels Tariff Studies processes, increased granularity
  - Recognition of ZONAL upgrades - Additional $32M in total upgrades
- SPP is asking for mitigation of reliability issues resulting from projects that are unable to be completed within the given SPP Expansion Plan need date
- Quarterly Requests for Review
  - Staff will not wait 12 months before making recommendations as reliability projects are identified
  - Issue “Notification to Construct”
  - Project owners can expedite necessary commitments

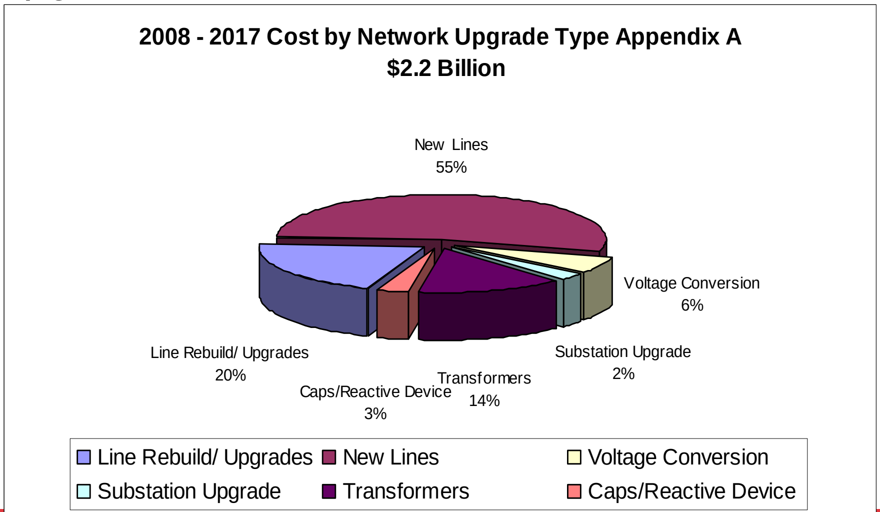
MOPC Concerns

1. "Some upgrades can not be implemented in time. Will the T.O. be at risk of "non-compliance" with the RE?"
   - "NO" - STEP tariff requirements (FERC OATT) & "RE Compliance" (NERC stds) are not the same.
   - Where necessary, mitigations will always be identified first.
   - STEP is only used to supplement some RE data requirements (Prevents duplication of effort, Supplements NERC stds "long term, category B" & "Category C & D")
2. "Many projects had the need date advanced. How did this happen?"
   - 11 reasons were identified as listed in the STEP on page 14 (96 models, new "scenario 5" model, forecast load changes, generation dispatch changes, etc.)

Some post-MOPC Adjustments to Appendix A and B

- Some errors in coding
- Non tariff participants removed from Appendix B
  - SPA, CLECO, INDN, Lea County – NM (Facilities not under tariff)
  - $47M adjustment
  - Reduces Appendix B totals, but does not change overall 2008 STEP totals
- Empire, Aurora cap bank
  - Project classification error
  - Base plan reliability to Zonal, $2.4M
  - Moves Appendix B, Zonal from $27M to $29M

Executive Summary 'Appendix A' All Upgrades, 2008-2017



Executive Summary
2007 STEP vs. 2006 STEP

Executive Summary of All Transmission Upgrades (Appendix A)	2007-2017 STEP	2006-2016 STEP
APPENDIX B:		
Zonal Upgrades	$29 M	$0
Base Plan Fundable, Reliability Upgrades	$718 M	$147 M
"Existing Facilities", pre January 1, 2006	$14 M	$55 M
Proposed Economic Upgrades	$465 M	$1.4 M
Outside Appendix B financial commitment window		
Regional Reliability upgrades	$296 M	$790 M
Zonal Criteria reliability upgrades	$4 M	$0
Reliability upgrades not under the OATT	$65 M	$15 M
Facility owner "planned projects"	$320 M	$378 M
Upgrades from Transmission Service Agreements*	$201 M	$52 M
Upgrades from Generation Interconnection Agreements	$88 M	$0
Total	$2.2 B	$1.4 B

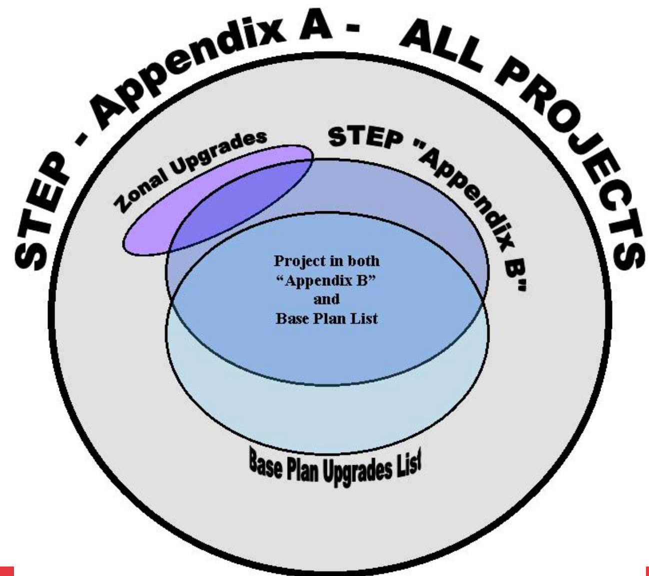
* Majority are Base Plan Funded

Recommendation

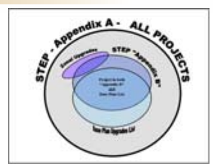
- The SPP RTO staff recommends that the SPP BOD approve this report, “SPP Transmission Expansion Plan 2008 -2017”
- The MOPC recommends that the SPP BOD approve the “SPP Transmission Expansion Plan 2008-2017”

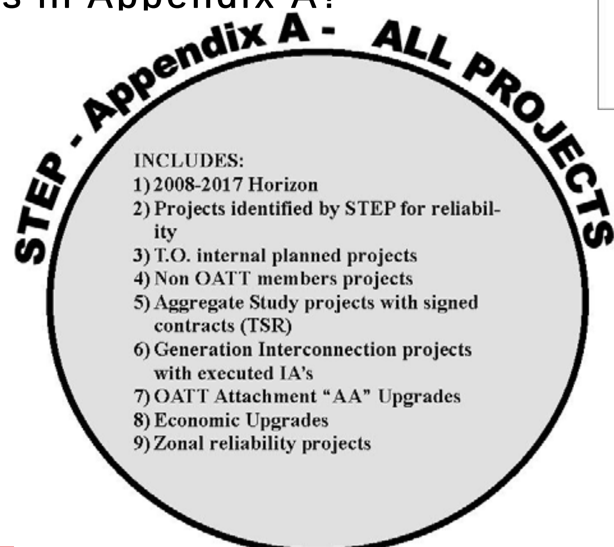
STEP Appendix B

SPP Transmission Expansion Plan



What is in Appendix A?

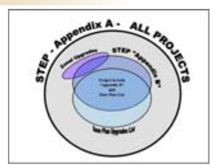




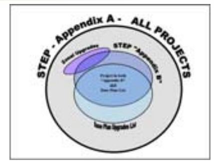
Appendix B
Financial Commitment Window

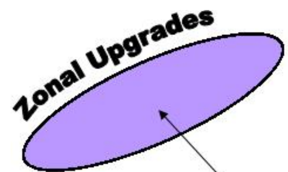
- 2 year window for 2006 STEP
- MOPC said, “too short”
  - TWG recommended 4 year window
- Appendix B
  - SPP reliability upgrades in financial commitment window years 1- 4, (2008-2011) recommended to receive a “Notification to Construct” (2006 “Letters of Authorization”)

What is in Appendix B?



What is in Zonal Upgrades?

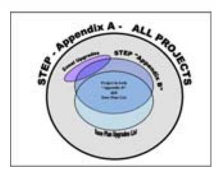




INCLUDES:

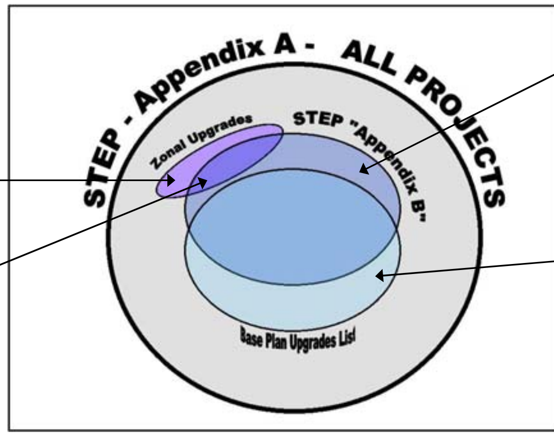
1) Zonal projects in financial commitment window
1) Zonal projects outside financial commitment window

What is in the Base Plan Upgrades List?



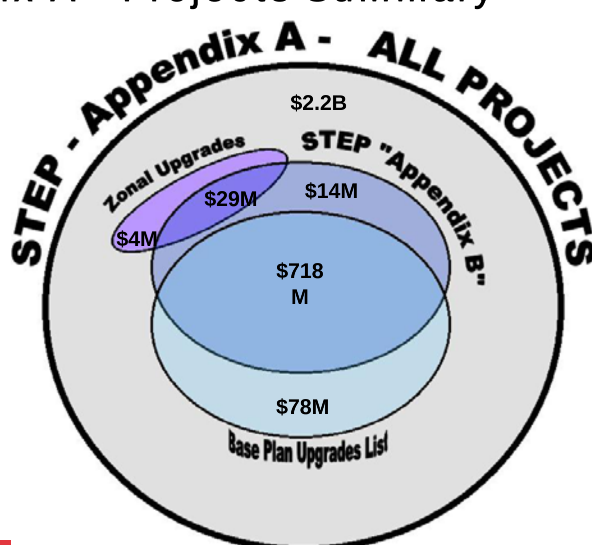
What is the difference between Appendix B, the Base Plan Upgrades List and the Zonal Upgrades?

- Zonal Upgrades outside commitment window
- Zonal Upgrades within commitment window



- Base Plan Upgrades List does not include “Existing Facilities” as defined by the SPP Tariff
- Appendix B does not include Base Plan Aggregate Study (TSR) projects

Appendix A – Projects Summary



Upgrades with LOA's Deferred/Replaced

- Etowah-Tribbey
- Elgin-Porter
- Bradley-Rush Springs
- Blue Springs-Duncan Road
- Curry County Interchange xfr
- South Hays-Hays-Vine Street
- Device – Pink Southwest
- Device – Cashion
- Device – Sunset
- Device – Hobart
- Device – Broken Arrow Water

Recommendation

- The SPP RTO staff recommends that the SPP BOD approves and directs the start of construction of network upgrades and/or SPP approve mitigation plans for those projects listed in Appendix 'B' of the "SPP Transmission Expansion Plan 2008-2017".
- The MOPC supports the SPP RTO staff recommendation that the SPP BOD approves and directs the start of construction of network upgrades, and/or SPP approved mitigation plans for those projects, listed in Appendix 'B' of the "SPP Transmission Expansion Plan, 2008 – 2017".
- New Upgrades in Appendix B New Letters for Notification to Construct added to Appendix B = $730 Million in projects

AEP Waiver Request

Waiver Request Summary

- **AEP reservation 1162214 studied in SPP-2006-AG3-AFS-9, requesting 455 MW from Turk Power plant**
- **AEP requests waiver Nov. 2, 2007**
- **Submittal to SPP BOD (within 120 days) - by March 1, 2008**
- **Turk Generation Interconnection Agreement has been executed**

Waiver Request Discussion

- Attachment J, Section C.2.ii - Allows all / part of excess above Safe Harbor limit to be classified as Base Plan funded, when new or changed DR exceeds five-year commitment
  - AEP reservation 1162214 is 20-year reservation
  - AEP committed to the life of Turk Plant - noted in Nov. 2007 letter to SPP
  - DR longevity consistent with SPP recommendation for approval of OGE, Westar, AECC, and OMPA waivers (approved by RSC and BOD)

CAWG Discussion of Turk Waivers

- Base plan funding maximum: 455 MW x $ 180,000/MW = $81,900,000
- March 2007 - proposed consideration of $180,000/MW Safe Harbor limit applies as funds for all Turk participants
- 618 MW x $ 180,000 = $111,240,000
- SPP-2006-AG3-AFS-9 required upgrades equal to $148,209,895 (Analysis should be complete since all customers agreed to remain after completion of Aggregate Facility Study)
- Staff recommended that Aggregate Study Base Plan funding analysis should not combine capacity in this manner:
  - Individual Project participants response factors may cause different upgrades
  - Not consistent with Attachment Z Section V: Cost Allocation for Requested Upgrades

SPP Recommendation for AEP Waiver

- **Recommend that Base Plan funding be increased to 100% of required E&C cost associated with addition of Turk plant DR for AEP**
- **The recommendation of the MOPC to the Board of Directors is to approve 100% the AEP waiver for such amount to fully Base Plan Fund the project.**

Empire Waiver Request

Empire Waiver Request

- The SPP recommendation is based on current SPP Tariff
- SPP is aware of policy issues raised by this waiver
- Policy decisions under consideration by CAWG/RSC, if approved, could significantly impact this recommendation

Review of EDE Request

- EDE reservation 1222640 studied in SPP-2007-AG1-AFS-6
- EDE requesting 100 MW from Cloud County Wind farm
- Aug. 2007 Letter – EDE requests waiver
- Tariff required submittal by Dec 21, 2007
- Nov. 2007 letter - EDE asked SPP to reconsider and issue revised recommendation for discussion by CAWG, RSC, MOPC, BOD (Jan. 2008)

Attachment J Section B.3

- Cost of Network Upgrades associated with new or changed Designated Resource shall be classified as Base Plan Upgrades if they are less than or equal to $180,000/MW times the lesser of:
  - (a) the planned maximum net dependable capacity applicable to the Transmission Customer or
  - (b) the requested capacity (the "Safe Harbor Cost Limit")

Net Dependable Capacity - Generally

- Net capability defined by NERC:
  - Net dependable capacity - maximum capacity a unit can sustain over an specified period, modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries
- Summer net capability of each unit may be used as winter net capability without further testing, at the option of the member

  (See SPP, FERC Electric Tariff, Fifth Revised Volume No. 1, Original Sheet No. 941)

Waiver Request Discussion

- Attachment J, Section C.2.ii - Allows all or part of excess above Safe Harbor Cost Limit to be classified as Base Plan Upgrade Cost, taking into account extent to which commitment to new or changed DR exceeds five-year commitment
  - EDE reservation 1222640 is 20-year reservation
  - Aug. 2007 letter to SPP - EDE commits to Cloud County Wind farm
  - Analysis based on AG1-2007-AFS-6 ($8,099,440 allocated to EDE). AG1-2007-AFS-7 ($5,560,217 allocated to EDE)
  - Base plan funding maximum calculated: 10 MW x $180,000/MW = $1,800,000
  - SPP recommends increase of $50,625 from $1,800,000 - Based on same calculation used for OGE / GSEC waivers and MW-MI calculation - indicating three zones benefiting from this commitment

Waiver – Fuel Diversity

- EDE requested waiver to foster fuel diversity
- Fuel diversity may be a positive result due to the addition of wind resources, however the specific target level of fuel diversity is a policy decision for state regulators (RSC), stakeholders, and the SPP Board of Directors, not SPP Staff
- FERC rejected language in SPP's Attachment J that would have permitted a waiver to foster fuel diversity
- SPP must show how parties paying associated waiver costs would benefit from increased fuel diversity
  (Southwest Power Pool, Inc., 112 FERC ¶ 61,319 (2005), P. 19.)
- EPAct 2005 directs states to take up issue and consider value of fuel diversity
  (PURPA Section 111(d) (12) of Section 1251 of EPAct 2005)

Waiver – Fuel Diversity

- Most states in SPP region are addressing this issue - not all at the same stage of investigation:
  - Missouri, Case No. EO-2006-0494
  - Kansas, Docket No. 07-GIME-578-GIE
  - Arkansas, Docket No. 06-028-R
  - Texas, Project No. 33672
- Significant industry sentiment that integrated resource planning - including consideration of fuel diversity - is driven by specific issues within load-serving entity
- Fuel diversity is a policy decision for state regulators (RSC), stakeholders, and Board of Directors.

SPP Conclusions and Recommendation – EDE Waiver Request

- The recommendation of SPP Staff is to provide an additional Base Plan funding of only $50,625 based on the 20 year reservation and existing tariff provisions. SPP staff acknowledges that a policy revision is under consideration by the CAWG/RSC; that if ultimately approved through the SPP/FERC process would alter the resulting recommendation.
- The Markets and Operations Policy Committee recommends to the Board of Directors to approve the Empire District Electric Company (EMDE) waiver for full base plan funding in conjunction with the CAWG recommendation.

Information Items

BA Consolidation

Southwest Power Pool

Why SPP is Investigating BA Consolidation

- **The Strategic Planning Committee has identified the offering of BA services by SPP as a high priority goal.**
- **BA Consolidation is considered necessary for the implementation of the next market.**
- **FERC requires SPP to study the feasibility of Consolidating BA's and file a report within 15 months of the February 1, 2007 start of the EI Market.**

Southwest Power Pool

Progress Made to Date

- **A functional method of consolidation has been proposed**
- **Costs and benefits have been estimated**
- **An Implementation Plan including a high level timeline has been developed**
- **A charter for a steering committee has been drafted**

Costs of BA Consolidation

- **Estimated Costs-**
- **Additional SPP BA staff and maintenance** **$1,350,000 (Annual)**
- **SPP systems changes and Licenses** **$1,800,000 (One Time)**
- **Current BA system changes** **$ 600,000 (One Time)**
- **Potential “throwaway” cost** **$ 650,000**

Benefits of BA Consolidation

- **Facilitation of Future Ancillary Service and Unit Commitment Markets**
- **Transfer of Liability**
- **Reduced Training and Certification Costs**
- **Potential Staffing Reductions**
- **Reduced Regulation Burden**
  - **Analysis performed based on actual data collected from last year indicated $3,800,000 to $19,000,000 annual settlement reduction (LIP * MWH reduction) would have resulted from using the proposed ACE diversity algorithm**
  - **Many believe that the potential savings associated with reduced regulation will be even more dramatic as intermittent resources are added to the footprint**

Project Implementation Assumptions

- High Level Timeline - It is estimated that software development and testing will take 11 months from "Go" decision
- SPP will have a functional test bed with the required capability in place before testing begins.
- Starting the detail design and coding stage with vendors is dependent on the cost/benefit report for future markets and an executed MOU.
- The future markets cost/benefit report will be delivered in September, 2008.
- SPP will agree to future market development in early October, 2008.
- SPP will continue to develop the Balancing Authority technical details to describe the tasks the BA will perform and how they will be accomplished.
- SPP will immediately begin to develop the requirements for the software changes needed to operate the Balancing Authority Area.
- SPP will immediately begin to develop Operating Procedures for the Balancing Authority.
- SPP will immediately begin necessary contractual design.
- There will be two meetings each month after January 2008 between SPP and Participants to develop the Technical and Policy details.

Project Implementation Risks

- Any extended delays at AREVA, SPP, or Participants due to resource unavailability and/or scope change.
- Regulatory process by states and FERC
- Resource availability due to other projects.
- Scope pushes project implementation in to the summer of 2009.
- If market footprint and BA footprint are not the same, scope change is inevitable.

Steering Committee

- The participating BAs believe a Steering Committee is now needed to:
  - Provide formal reporting relation with MOPC
  - Facilitate meetings of subject matter experts
  - Oversee development of technical details, policies, and agreements needed to implement
  - Ensure coordination with appropriate state and federal regulatory agencies
- Comprised of at least one member from each current BA in the SPP Market footprint and any other signatory to an MOU

Recommendation

- The MOPC approved the charter for the CBA Steering Committee and direct the group to continue working on activities that can be accomplished prior to the Cost-Benefit Task Force completion

Generation interconnection Queue Task Force

Generation Interconnection Queue

- **Large number of requests for Interconnection have been received across the country**
  - **FERC held a technical conference last December to address the issue**
  - **Concern is growing that the back log is causing problems for developers**
- **Generation Interconnection Queue as of 12/31/2007**
  - **87 Active Requests - 78 Wind (19,400 MW), 9 Fossil (3,000 MW)**
  - **10 Interconnection Agreements (IAs) Pending, 16 IAs signed during 2007 - 10 Fossil (4,641MW), 6 Wind (716 MW)**
  - **This time last year we had 52 active requests - 34 wind (6,463 MW), 18 Fossil (7,656 MW) with 8 Interconnection Agreements pending**

Impacts

- SPP Staff
  - Tremendous increase in workload
  - Difficulties in adding staff
  - SPP has added staff, but having to train
  - Consultants are harder to find due to their workloads
- Generation Interconnection Customers
  - Increased request processing time
  - All requests are studied on a non-discriminatory basis. Therefore, delayed study timeframes for both wind farms which are intermittent low capacity resources as well as base load units.

Difficulties in Studying Wind Generation Interconnection

- Wind resources located in western areas of SPP where there is a weaker transmission system
- Lack of voltage support from wind turbines
- Apparent oversupply of Interconnection Requests for available demand and transmission infrastructure.
- Multiple restudies encountered when customer changes the type of wind turbine to be used for the project.
- Accounting for Wind Farms with Interconnection Agreements that have been signed but are on suspension.

GQTF

- In response, the RTWG formed the GQTF
- GQTF is to study the issues, look at options and come back to the RTWG with recommendations by July
- Report to the MOPC in October or next January

WE ARE LOOKING FOR A FEW GOOD PERSONS TO WORK ON THE GQTF!!

Draft Process For Economic Projects

- SPP receives Sponsor Letter, which initiates a project
- Negotiate Sponsor Contract
- Presented Sponsor Contract to TOs with Right of First Refusal
- If TO decides to construct, negotiate construction contract and build project
- If TO declines to construct, put project up for bids with standard construction contract
- Review bids, award bid and build project
- TOCTF recommends the RTWG address the selection of a qualified entity should the incumbent TO not carry out STEP obligations

Cost Benefit Task Force

CBTF Update

- **November 8 - MOPC forms task force**
- **November 15 - Task force chartered**
- **Met in conference calls on November 15 and December 19, 2007 and January 4, 2008**
- **MWG continuing to prepare High Level Market Design and Request for Proposal (RFP) for Cost Benefit Study**
- **Study scenarios to include a Day Ahead Market (DAM), Ancillary Service (A/S) Market, and a Simplified DAM**

Study Scenarios

- Base case – EIS Market
- Change cases –
  - DAM with Unit Commitment only (No A/S)
  - DAM with Unit Commitment and A/S Market
  - A/S Market only
  - Simplified DAM with Unit Commitment (No A/S)
- Also includes several sensitivities
  - Incremental market changes
  - Physical vs. financial transmission rights

CBTF Timeline

- January 7 – Request for Interest (RFI) e-mailed and posted on SPP organizational web site
- RFI Q&A to be posted on same web site
- January 18 - RFI responses due to SPP by 5 pm
- January 25 - RFP to be e-mailed to vendors and posted on web site
- February 22 - After RFP Q&A period, responses to RFP due to SPP by 5 pm

CBTF Timeline (con't)

- February 29 – Decision on short list of finalists
- March 12 & 13 – Short list vendor presentations
- March 14 – Final selection of study vendor
- March 21 – Finalize assumptions for study
- Study vendor to provide monthly updates to MWG (with forward to MOPC Members)
- October 1, 2008 - Cost Benefit Study completed

Aggregate Study Improvement Task Force

ASITF Recommendation

Alternative A

- Implement a screening study to that will give customers the opportunity to reduce the number of requests
- Remove system impact study
- Limit the number of facility studies in a given aggregate to three
- Paperwork must be complete by the close of the study window (study agreement, Network Service Application if applicable)
- Each Aggregate Study will be priced on a per request basis rather than a per MW basis
- A cost causer methodology will be implemented for the Aggregate Study.
- Customers that drop from the process and do not meet the exemption criteria will pay a portion of the study costs up to the full amount for the next study.

Alternative B

- Implement a screening study to that will give customers the opportunity to reduce the number of requests
- Remove system impact study
- Limit the number of facility studies in a given aggregate to three
- Paperwork must be complete by the close of the study window (study agreement, Network Service Application if applicable)
- Each Aggregate Study will be priced on a per request basis rather than a per MW basis
- A cost causer methodology will be implemented for the Aggregate Study.
- Customers that drop from the process and do not meet the exemption criteria will pay a portion of the study costs capped at $50,000 per withdrawn request for the next study.

SPP Southwest Power Pool

Carl A. Monroe

501-614-3218
cmonroe@spp.org