QUARTERLY METRICS REPORT
FOR THE SOUTHWEST POWER POOL (SPP)
ENERGY IMBALANCE SERVICES (EIS) MARKET

Prepared by:

The SPP Market Monitoring Unit and
Boston Pacific Company, Inc.

July 20, 2007

LIST OF TABLES AND FIGURES

EXECUTIVE SUMMARY

I. MARKET ACTIVITY

Table One:	Electricity Sales in the EIS Market by Month and for the Quarter
Table Two:	Electricity Purchases in the EIS Market by Month and for the Quarter

II. PRICES

Table Three:	Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Hourly Price Statistics for the Quarter
Table Four:	Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Hourly Average Prices by Month and for the Quarter
Table Five:	Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Volatility by Month and for the Quarter
Figure One:	Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Daily Price Statistics for the Quarter
Figure Two:	Price Duration Curve for the EIS Market for the Quarter
Figure Three:	Price Duration Curve for the EIS Market by Month
Figure Four:	Price Duration Curve for the EIS Market by Month for the 50 Highest Prices in each Month
Figure Five:	Average Quarterly Price to Load by Load Settlement Location
Table Six:	Quarterly Volatility and Price Range by Load Settlement Location
Figure Six:	Quarterly Price Range by Load Settlement Location
Table Seven:	Quarterly Flagged Interval Prices Beyond Thresholds
Figure Seven:	Path of Daily Henry Hub Natural Gas Prices Compared to SPP On-Peak Daily Average for the Quarter
Figure Eight:	Daily Henry Hub Natural Gas Prices Compared to SPP On-Peak Daily Average for the Quarter

III. PARTICIPATION

Table Eight:	Percent of Total Capacity Made Available to the EIS Market by Month and for the Quarter
Figure Nine:	Capacity Made Available Compared to Load in the SPP Footprint
Table Nine:	Dispatchable Range of Capacity Made Available to the EIS Market by Month and for the Quarter

IV. TRANSMISSION CONGESTION

Table Ten:	Price Divergence as a Rough Indicator of Transmission Congestion
Table Eleven:	Transmission Congestion Summary by Flowgate (Top 15) for the Quarter
Table Twelve:	Transmission Congestion Summary by Corridor for the Quarter
Table Thirteen:	Top 15 Congested Flowgates by Month and for the Quarter
Figure Ten:	Transmission Congestion Map Summary by Transmission Corridor for the Quarter
Figure Eleven:	Transmission Congestion Map Summary by Flowgate for the Quarter
Table Fourteen:	Congestion Resolution: Percent Achieved by EIS Market

V. MARKET POWER MEASUREMENT AND MITIGATION

Table Fifteen:	Effect of FERC and SPP Offer Caps
Table Sixteen:	Shares of EIS Market Sales for all Market Participants (anonymous, ranked)
Table Seventeen:	Shares of Capacity Made Available at the Peak Hour of the Month and the Quarter (anonymous, ranked)

VI. FUEL TYPE

Table Eighteen:	Generation by Fuel Type by Month and for the Quarter
Table Nineteen:	Generation at the Margin by Month and for the Quarter

DISCLAIMER

EXECUTIVE SUMMARY

INTRODUCTION

- The SPP Energy Imbalance Services (EIS) Market started on February 1, 2007 and has now completed five months of operation.

- The SPP Market Monitoring Unit (MMU) with assistance from Boston Pacific Company, Inc., as the External Market Advisor (EMA), has prepared a Monthly Metrics Report for each of the first five months. These are all available on the SPP web site under the Market Monitoring page.

- A Quarterly Metrics Report also is required and this is the first of these Reports. Because it is the first of these Reports, it actually covers *the first five months* of EIS Market operation. The purpose of the Quarterly Metrics Report is to provide a summing up (a "roll up") of the data for the quarter (or, in this one case, for the first five months) and also to present data which allows a side-by-side comparison of performance in each month. In future Quarterly Reports, a section will be added to briefly raise policy or enforcement issues that arose during the quarter.

MARKET ACTIVITY

- As is the nature of an imbalance market, a *sale* is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled. Similarly, a *purchase* is made by a Market Participant when either (a) it generates less than it has scheduled and/or (b) its actual load is more than it has scheduled.[1]

- For the first five months of operation, EIS Market sales totaled 5.6 million MWh. A total of $291 million were paid to suppliers.

- Purchases differ from sales in both quantity (MWh) and dollar value. Purchases for the five-month period were about 5.7 million MWh in quantity and about $280 million were paid by buyers. The difference between sales and purchase quantities is due to losses. The difference in terms of dollar value is due to divergent locational price being paid to suppliers and by buyers.

[1] For example, say a Market Participant schedules and offers 100 MWh of generation from a power plant; by scheduling and offering, this power plant becomes Dispatchable by the EIS Market. If the power plant is dispatched at 125 MWh, it made a 25 MWh sale to the EIS Market. In contrast, if it is dispatched at 70 MWh, it made a 30 MWh purchase from the EIS Market. If a Market Participant schedules 100 MWh of use (load), but actually uses 125 MWh, it has purchased 25 MWh; if its actual use is only 70 MWh, it sold 30 MWh to the EIS Market.

- June brought a significant increase in sales. While sales were about 1 million MWh in each of the first four months of operation, June sales were 1.4 million MWh. In terms of dollars paid to suppliers, the first four months were roughly in the range of $50 million – June was almost $84 million.

- Another way to measure the June increase is to compare daily averages. Daily average MWh sales in June were 25% above the five-month average. Daily average dollar sales were 44% above the five-month average.

- To put sales and purchases in context, note that we estimate a total of 66.9 million MWh were used (total load) in the SPP footprint from February through June of 2007. EIS Market Sales (at 5.6 million MWh) were equal to 8.4 % of total load. Across the five months, the share of load ranged from a low of 7.5% in February to a high of 9.3% in June.

PRICES

- The SPP-wide, weighted average hourly price to consumers (at load) for the first five months of operation in 2007 was $51.51/MWh in the EIS Market.

- These SPP-wide hourly prices ranged from a low of *a negative* $105.82/MWh to a high of $386.16/MWh. The median price was $49.61/MWh. (The median means half the prices were above this level and half below.)

- The SPP-wide weighted average hourly on-peak price was $59.75/MWh and, for off-peak, the average hourly price was $42.88/MWh.

- Volatility of SPP-wide hourly prices was significant, as indicated by a Coefficient of Variation of 52%. (This means that the SPP-wide price in any given hour differed, on average, from the five-month average by 52%.).

- Only rough comparisons can be made to other energy imbalance markets because of differences in market structure and current data limitations. As to average quarterly price, the SPP weighted average price of $51.51/MWh (a) was about 3.6% higher than the MISO simple average price of $49.73/MWh and (b) was about 5.4% below the ERCOT simple average of $54.43/MWh.[2] Volatility was lower in the SPP Market than in the MISO and ERCOT markets with their Coefficients of Variation at 66% and 83%, respectively.

- In addition to the analysis of SPP-wide hourly prices for load, we also assessed prices at 5-minute deployment intervals for both load and generation settlement

[2] The SPP simple average price was $49.00/MWh, which was lower than both the MISO and ERCOT simple averages.

locations. These are the most granular price data. These price data can be summarized as follows for the first five months of 2007 operation:

- 96.86% were in the zero to $100/MWh range;
- 0.71% were negative;
- 2.21% were in the $100 to $400/MWh range, and;
- 0.22% were above $400/MWh.

- We expect swings in natural gas prices to drive on-peak electricity prices. However, SPP-wide EIS on-peak prices varied more widely than natural gas prices varied. As seen later, transmission congestion also plays a role in driving price variation in SPP.

PARTICIPATION

- Participation in the EIS Market, which is voluntary, was robust throughout the five month period, with 79% of on-line capacity being made available on average to the EIS Market. (For the purposes of this Report, on-line capacity includes only Available and Self-Dispatched capacity.) For all the five months, the participation rate was about the same – the range was from 77% to 81%.

- Capacity made available to the EIS Market was consistently equal to a high percentage (about 97%) of average daily load in the SPP footprint.

- For the capacity made available to the EIS Market, the dispatchable range averaged 47% which is another, more strict indication of robust participation. (Dispatchable range indicates the portion of the capacity that can be moved up and down as customer need varies.)

- As demonstrated in the Monthly Metric Reports, the one possible concern with participation continues to be low ramp rate; a ramp rate dictates how fast a power plant can be moved from one level of operation to the next.

TRANSMISSION CONGESTION

- Prices in the EIS Market diverge by location when there is transmission congestion.

- Congestion was pervasive in time in the sense that prices at load diverged in 63% of all hours in the five-month period. This was down in May to a low of 39%, but then rose to a high of 92% in June. For on-peak hours only, prices diverged in 67% of the hours. (Again, June set the high at 95% of the hours.) On average, prices in on-peak hours with congestion were 16.6% higher than in on-peak hours without congestion.

- We also wanted a sense of how many transmission facilities (flowgates) were causing the congestion in these intervals. We found that the number of congested flowgates ("bottlenecks") is small.

- To confirm this view that the transmission bottlenecks are few in number, we traced congestion to specific flowgates. We found that the five most congested flowgates were involved in 72% of the instances. (The five are SPP-SPS Ties, Jeffrey to Summit (two temporary flowgates), SPS North-South, Lone Oak to Sardis, and Flintcreek to Tontitown.).

- The start of the EIS Market expanded the range of transactions that can be used to relieve transmission congestion. It also meant that congestion could be relieved by EIS Market response (re-dispatch) as well as by traditional curtailment through transmission loading relief (TLRs). The FERC asked the MMU to report monthly on "how congestion and imbalances were resolved, whether through TLR or imbalance market mechanisms".

- The MMU report, as well as the implementation of the new congestion management tools, is a work in progress. However, the data filed by the MMU indicate that 87.9% of the congestion for the five-month period in SPP was resolved by re-dispatch of the EIS Market. This percentage is high in all five months, ranging from a low of 81.7% to a high of 92.9%. This is a good step forward in the sense that market resolution is thought to be less costly than physical curtailment.

MARKET POWER MEASUREMENT AND MITIGATION

Effect of Offer Caps

- The FERC's Offer Cap was set at $400/MWh for the first three months of EIS Market operations; and has been set at $1,000/MWh since. The FERC offer cap applies at all times.

- SPP's Offer Cap applies only when there is transmission congestion. The level of the offer cap varies by Resource.

- The FERC and SPP caps are the most explicit mitigation tools for economic withholding. As one indicator of effect, we identify the portion of time when accepted offers are very close (within 5%) of the offer cap. That is, we determine the portion of time in which it appears either cap is restricting offers and, in the absence of the cap, offers would be higher.

- In the first five months of operation, the effect of the FERC Offer Cap is negligible. Offers were accepted near the cap in only 0.04% of all opportunities (all "Resource Intervals").
- In the five months, the SPP Offer Cap was *imposed* in a significant number of opportunities (Resource Intervals), but its effect was negligible. The SPP Offer Cap was imposed in 15.24% of all Resource Intervals, but offers were accepted near that cap for a negligible share (.0066%) of Resource Intervals.

Market Shares

- Both structural and behavioral indicators should be used to judge the competitiveness of any market. Among the structural indicators are the number of bidders, the number of winners, and the market share of winners. Although we go into some detail here, these indicators are just that, indications of competitiveness; they are not hard and fast numerical standards.

- In terms of the number of bidders and winners, there were 21 Market Participants in the EIS Market.[3] Of these, 15 won at least a 1% share of the EIS Market sales this quarter. This is a good number of bidders and winners.

- We want a large number of bidders because it often leads to aggressive bidding, and also because it mitigates against coordinated or collusive bidding; it is harder for bidders to police and enforce a collusive scheme with a large number of bidders.

- Another 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 in SPP – that is, the 20% is not a hard and fast limit to market-based rate authority.

- Among the winners in the SPP EIS Market, none have a market share exceeding 20%. Four have market shares in the 10% to 19% range. All others have shares less than 10%.

- 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

[3] WestPlains Energy (Aquila) consolidated with Sunflower Electric in April 2007. For the purposes of this report, we treat them as one entity for all five months in the quarter.

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 un-concentrated. 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.

- As an additional measure of structural competitiveness, we calculated an HHI in two ways. For the first, we used the market shares measured as *share of sales to the EIS Market*. With this measure, the HHI was 1,134; which puts it in the low end of the moderately concentrated range, indicating a low potential for market power abuse.

- For the second, calculation of an HHI, we measured market share very differently. Instead of shares of EIS sales, we calculated *shares of capacity made available to the EIS Market at the peak hour of the Quarter*. Using this measure of market share, the HHI is 1,450, which puts it in the mid-range of the moderately concentrated range indicating a somewhat higher potential for market power abuse.

FUEL TYPE

- There has been considerable interest in adding data on the fuel types used in the SPP footprint. At the outset, we should say that the data are not easy to come by and the estimates rely on several data sources that must be mapped into one another. However, we believe the estimates here are reasonable and as expected.

- We assess fuel type from two perspectives. The first is to simply ask what fuels were used to generate all the electricity in the SPP footprint. As expected, we found that on average coal was used for about 65% of the electricity generation and that natural gas (or oil) was used for about 25%. Nuclear accounted for about 6% and wind accounted for 2.5%.

- The second perspective is to ask which fuels are "at the margin" and, thereby, which fuels determined locational prices in the EIS Market.[4] Also, as expected, we see that coal and natural gas flip their respective roles when we look at fuels at the margin. That is, natural gas (or oil) are at the margin for about 75% of the time and coal is at the margin for about 25% of the time.

[4] For the purposes of this report, a marginal resource was defined as a resource that was available to the market and had an offer price within $0.20 of its administered price.

I. MARKET ACTIVITY

Table One

Electricity Sales in the EIS Market by Month
and for the Quarter

Month	MWh Sold by Market Participants	Dollars Received by Market Participants
February	982,439	52,552,411
March	1,084,657	49,846,702
April	1,052,692	52,640,111
May	1,103,790	52,296,674
June	1,413,136	83,835,716
Quarter	5,636,714	291,171,614

Month	Average Daily MWh Sold by Market Participants	Average Daily Dollars Received by Market Participants
February	35,087	1,876,872
March	34,989	1,607,958
April	35,090	1,754,670
May	35,606	1,686,989
June	47,105	2,794,524
Quarter	37,578	1,941,144

1) Source: SPP DSS.
2) A sale is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled.
3) Initial Settlement values were used because Final Settlement statements were not available for all months. Final Settlement MWh values for February, March, and April are anywhere from 0%-5% lower than the Initial values.
4) The dollars received numbers we report here for February are slightly different from those we reported in the February monthly report. This is because we now use a more accurate method to calculate dollars received from sales.

Table Two

Electricity Purchases in the EIS Market by Month and for the Quarter

Month	MWh Purchased by Market Participants	Dollars Paid by Market Participants
February	1,005,583	51,164,242
March	1,099,568	45,836,392
April	1,052,875	53,053,948
May	1,119,682	52,665,570
June	1,415,285	77,641,662
Quarter	5,692,993	280,361,814

Month	Average Daily MWh Purchased by Market Participants	Average Daily Dollars Paid by Market Participants
February	35,914	1,827,294
March	35,470	1,478,593
April	35,096	1,768,465
May	36,119	1,698,889
June	47,176	2,588,055
Quarter	37,953	1,869,079

1) Source: SPP DSS.
2) A purchase is made by a Market Participant when either (a) it generates less than it has scheduled and/or (b) its actual load is more than it has scheduled.
3) Initial Settlement values were used because Final Settlement statements were not available for all months. Final Settlement MWh values for February, March, and April are anywhere from 0%-5% lower than the Initial values.
4) The dollars paid numbers we report here for February are slightly different from those we reported in the February monthly report. This is because we now use a more accurate method to calculate dollars paid for purchases.

II. PRICES

Table Three

Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Hourly Price Statistics for the Quarter

Region	Average Price	Max. Price	Min. Price	Median Price	Volatility	Average On-Peak Price	Average Off-Peak Price
SPP	$51.51	$386.16	($105.82)	$49.61	52%	$59.75	$42.88
MISO	$49.73	$249.52	($22.62)	$40.36	66%	$66.06	$34.30
ERCOT	$54.43	$1,500.00	($238.74)	$50.97	83%	$62.10	$47.59

Note: We use the term "rough comparison" because of inherent differences in the structure of the three markets and also because of the differences in how prices for SPP, MISO, and ERCOT are calculated. For SPP prices we used weighted averages, and for MISO and ERCOT we used simple averages.

1) All prices are per MWh.
2) Note that SPP and MISO deploy on a 5-minute interval and both are nodal markets. ERCOT deploys on a 15-minute interval and is a zonal market.
3) For SPP, the average price is the weighted average of all hourly locational imbalance prices (LIPs) for ten load settlement areas; weights are total hourly load in the footprint (not EIS-only load).
4) Because of interim data limitations, the averages for MISO and ERCOT are simple averages of hourly prices, not load weighted. Had we taken a simple average for SPP, SPP's averages would have been lower. The average price would have been $49.00, the average on-peak price $58.26 and the average off-peak price $40.75.
5) The maximum, minimum, and median prices are taken across all hours in the quarter.
6) Volatility is measured by Coefficient of Variation, which is the standard deviation across all hours divided by the simple average of hourly prices.
7) On-peak hours include hour-ending 7:00 am to hour-ending 10:00 pm. Off-peak hours are hour-ending 11:00 pm to hour-ending 6:00 am. Weekends and NERC holidays are also off-peak.
8) The SPP data is from the Market Operating System.
9) MISO data is publicly available at http://www.midwestiso.org/publish/Folder/10b1ff_101f945f78e_-75e70a48324a
10) ERCOT data is publicly available at http://www.ercot.com/mktinfo/services/bal/index.html

Table Four

Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Hourly Average Prices by Month and for the Quarter

Region	February	March	April	May	June	Quarter
SPP	$56.99	$46.13	$51.25	$49.00	$53.77	$51.51
MISO	$62.65	$46.34	$51.16	$45.87	$43.73	$49.73
ERCOT	$52.65	$54.18	$55.68	$53.89	$55.65	$54.43

1) For SPP, the average price is the weighted average of all hourly locational imbalance prices (LIPs) for ten load settlement areas; weights are total hourly load in the footprint (not EIS-only load).
2) SPP prices reported for February and March might be slightly different from those reported in the monthly reports because a more precise calculation method was used for this report.

Table Five

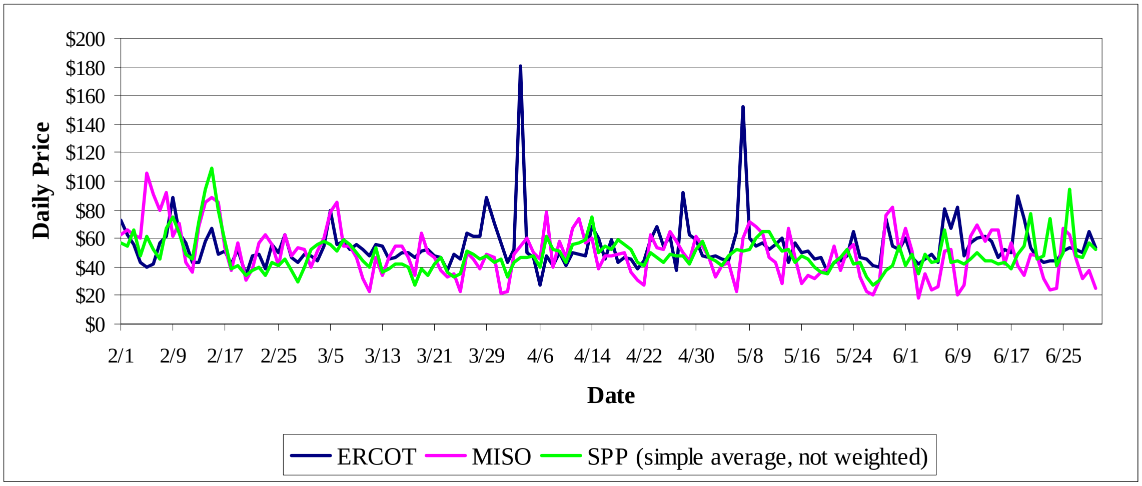
Rough Comparison of SPP-Wide, MISO-Wide, and ERCOT-Wide Volatility by Month and for the Quarter

Region	February	March	April	May	June	Quarter
SPP	51%	37%	34%	44%	76%	52%
MISO	58%	57%	54%	71%	85%	66%
ERCOT	53%	50%	125%	96%	57%	83%

1) Volatility is measured by Coefficient of Variation, which is the standard deviation across all hours divided by the simple average of hourly prices.
2) SPP volatility reported for February and March might be slightly different from those reported in the monthly reports because a more precise price calculation method was used for this report.

Figure One

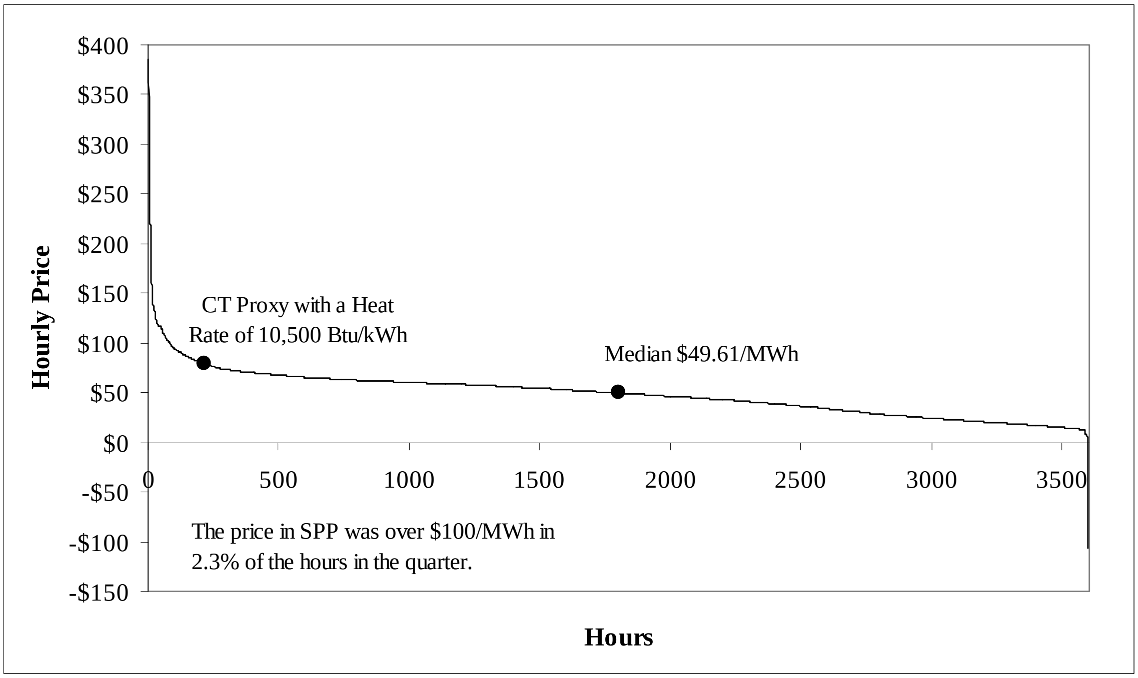
Rough Comparison of SPP-Wide, MISO-Wide,
and ERCOT-Wide Daily Price Statistics for the Quarter



1) The daily averages represent the simple average of the hourly prices.

Figure Two

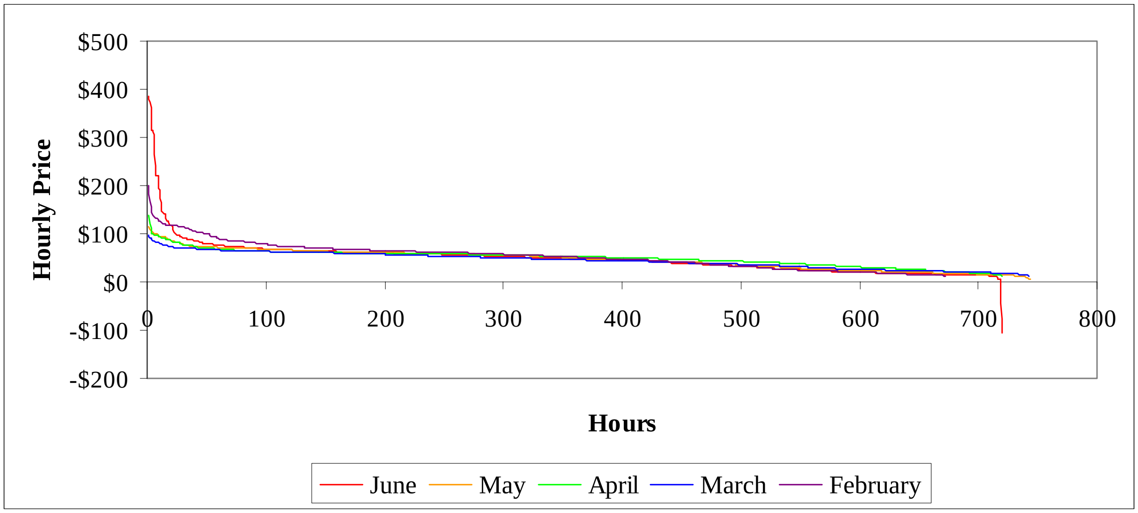
Price Duration Curve for the EIS Market
for the Quarter



1) A price duration curve represents all hourly prices in descending order plotted against the hours that price level prevailed. It is not chronological.
2) The CT Proxy reflects the average variable cost of operating a Combustion Turbine with a heat rate of 10,500 Btu/kWh and average trading day Henry Hub gas prices. The average is $79.02/MWh – the SPP-wide price was above this level in 5.9% of the hours in the Quarter.

Figure Three

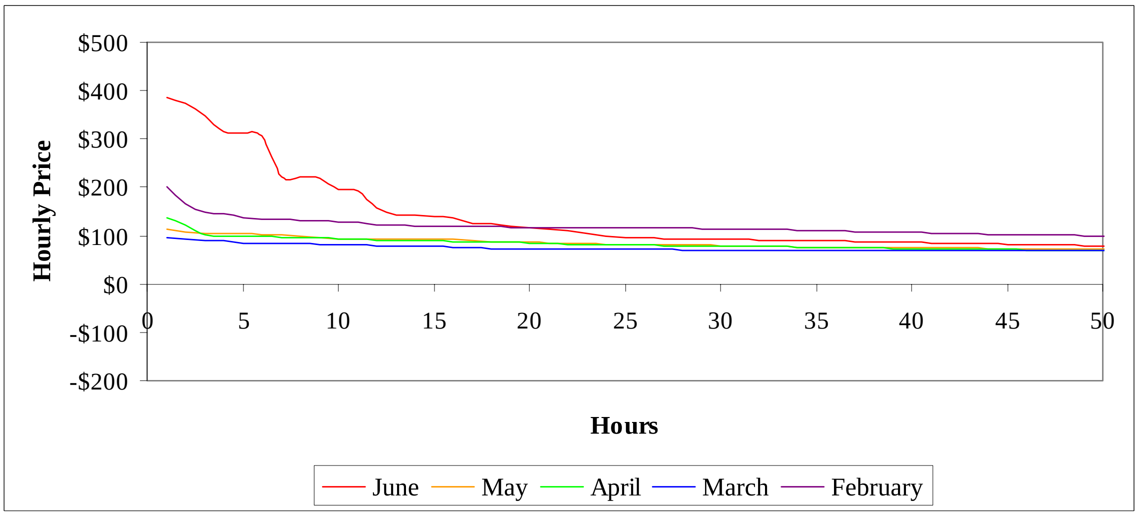
Price Duration Curve for the EIS Market by Month



1) A price duration curve represents all hourly prices in descending order plotted against the hours that price level prevailed. It is not chronological.

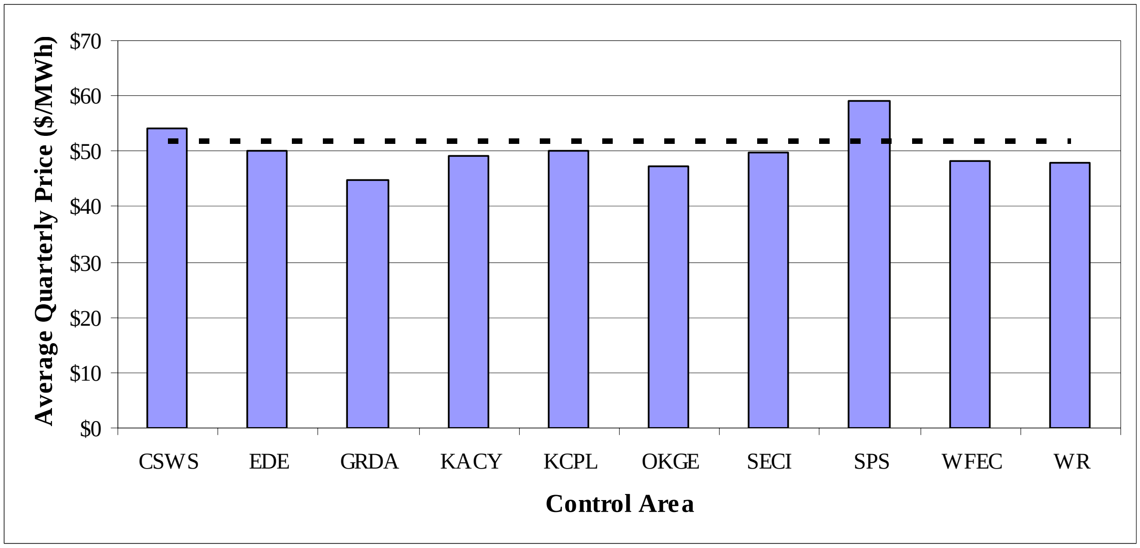
Figure Four

Price Duration Curve for the EIS Market by Month for the 50 Highest Prices in each Month



1) A price duration curve represents all hourly prices in descending order plotted against the hours that price level prevailed. It is not chronological.

Figure Five
Average Quarterly Price to Load by Load Settlement Location



1) The price is the weighted average of all hourly locational imbalance prices (LIPs) for the ten load settlement areas, weighted by the total hourly load in the settlement area (not EIS-only load).

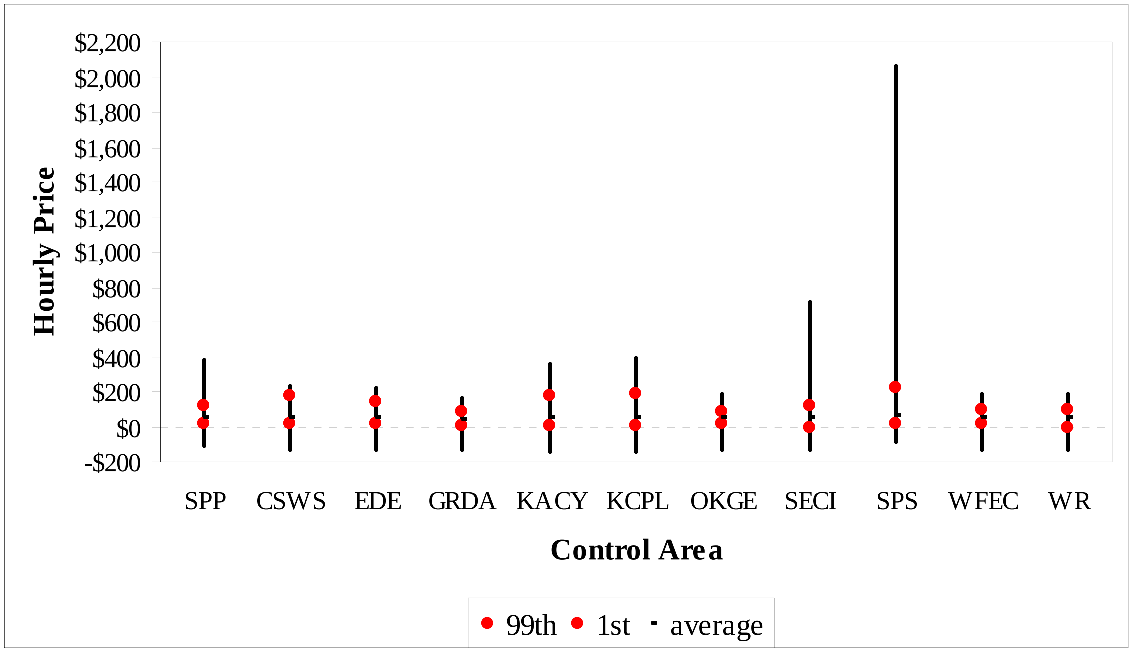
Table Six

Quarterly Volatility and Price Range by Load Settlement Location

Control Area	Volatility	Minimum Prices		Maximum Prices	
		Value	Date of Value	Value	Date of Value
SPS	159%	-$85.91	6/25/07 1:00 AM	$2,064.46	6/23/07 3:00 PM
KCPL	68%	-$137.45	6/21/07 2:00 AM	$393.99	2/5/07 12:00 PM
SECI	67%	-$135.36	6/21/07 2:00 AM	$712.85	4/23/07 8:00 AM
KACY	66%	-$137.50	6/21/07 2:00 AM	$365.15	2/5/07 1:00 PM
CSWS	54%	-$136.77	6/21/07 2:00 AM	$231.77	2/15/07 11:00 PM
EDE	54%	-$136.88	6/21/07 2:00 AM	$219.69	2/15/07 11:00 PM
WR	49%	-$135.06	6/21/07 2:00 AM	$191.11	2/15/07 11:00 PM
GRDA	44%	-$136.78	6/21/07 2:00 AM	$168.82	2/15/07 11:00 PM
WFEC	43%	-$136.52	6/21/07 2:00 AM	$193.44	6/8/07 1:00 AM
OKGE	42%	-$136.67	6/21/07 2:00 AM	$193.31	6/8/07 1:00 AM
SPP	52%	-$105.82	6/21/07 2:00 AM	$386.16	6/26/07 3:00 PM

1) Volatility is measured by Coefficient of Variation, which is the standard deviation across all hours divided by the simple average of hourly prices.
2) Minimum Value represents the minimum hourly price for the quarter.
3) Date of Minimum Value is the hour in which the price occurred.
4) Maximum Value represents the maximum hourly price for the quarter.
5) Date of Maximum Value is the hour in which the price occurred.

Figure Six
Quarterly Price Range by Load Settlement Location



1) This shows the range of hourly prices for each control area. The black line shows the full range of prices. The red dots signify the 1st and 99th percentile. This means that 98% of the prices fell between the two red dots.

Table Seven

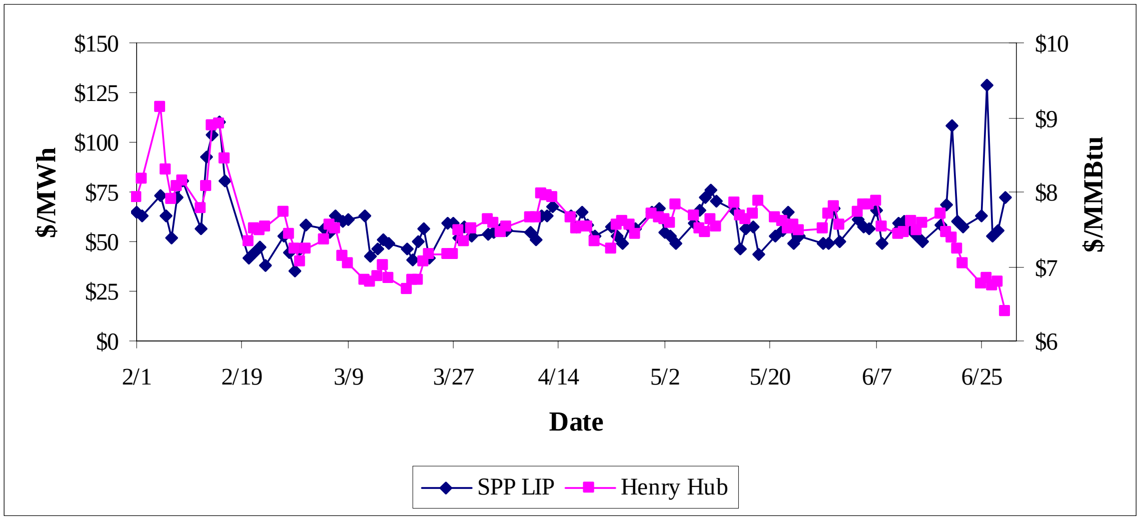
Quarterly Flagged Interval Prices Beyond Thresholds

Month	Less Than $0		Between $0 and $100		Between $100 and $400		Greater Than $400	
	Count	% of all observations	Count	% of all observations	Count	% of all observations	Count	% of all observations
February	25,862	1.13%	2,153,651	94.04%	103,880	4.54%	6,783	0.30%
March	24,095	0.97%	2,419,939	97.21%	44,029	1.77%	1,417	0.06%
April	5,978	0.26%	2,264,954	98.56%	22,776	0.99%	4,266	0.19%
May	7,193	0.29%	2,438,198	98.59%	24,990	1.01%	2,675	0.11%
June	21,698	0.90%	2,313,788	95.80%	68,927	2.85%	10,867	0.45%
Quarter	84,826	0.71%	11,590,530	96.86%	264,602	2.21%	26,008	0.22%

1) All prices are per MWh.
2) Counts are computed as the number of dispatch interval LIPs within a certain threshold anytime in a given time period for resource and load settlement locations.
3) Percentage (%) of all observations is computed as the count of dispatch interval LIPs within a certain threshold divided by the total number of dispatch interval LIPs for the month or the quarter for resource and load settlement locations.
4) The number of settlement locations change from month to month as settlement locations are added and deleted from the SPP database.

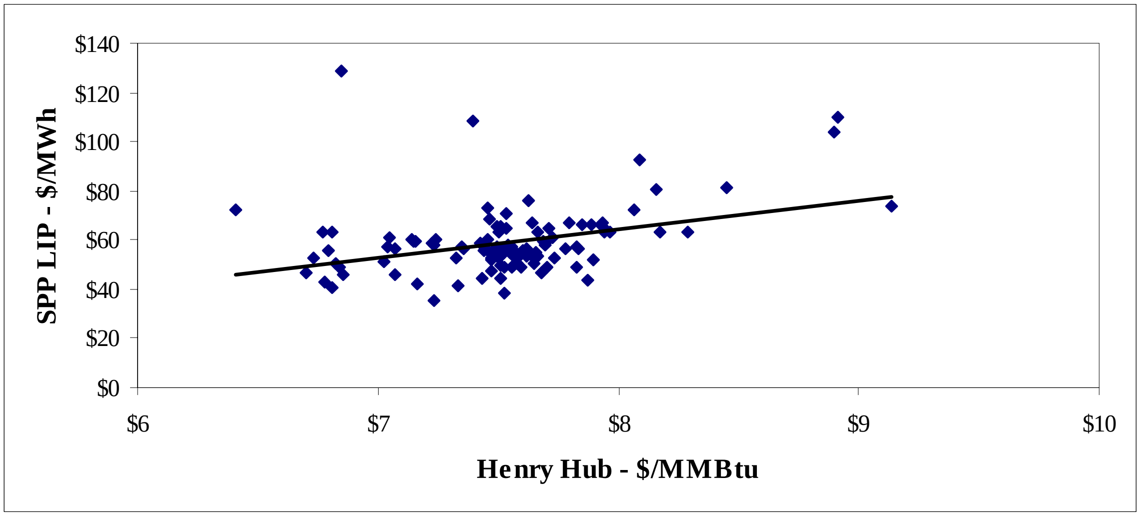
Figure Seven

Path of Daily Henry Hub Natural Gas Prices
Compared to SPP On-Peak Daily Average for the Quarter



1) SPP On-Peak Daily Average Prices represent the load-weighted average for all on-peak load settlement area LIPs for each day.
2) On-Peak Daily Average Prices do not include weekends or holidays.
3) Natural gas prices are Henry Hub trading day prices.

Figure Eight
Daily Henry Hub Natural Gas Prices
Compared to SPP On-Peak Daily Average for the Quarter



1) The SPP LIP and Henry Hub have a 0.36 correlation for the quarter (February to June). If we just look at February to May the correlation was 0.66.
2) SPP On-Peak Daily Average Prices represent the load-weighted average for all on-peak load settlement area LIPs for each day.
3) On-Peak Daily Average Prices do not include weekends or holidays.
4) Natural gas prices are Henry Hub trading day prices.

III. PARTICIPATION

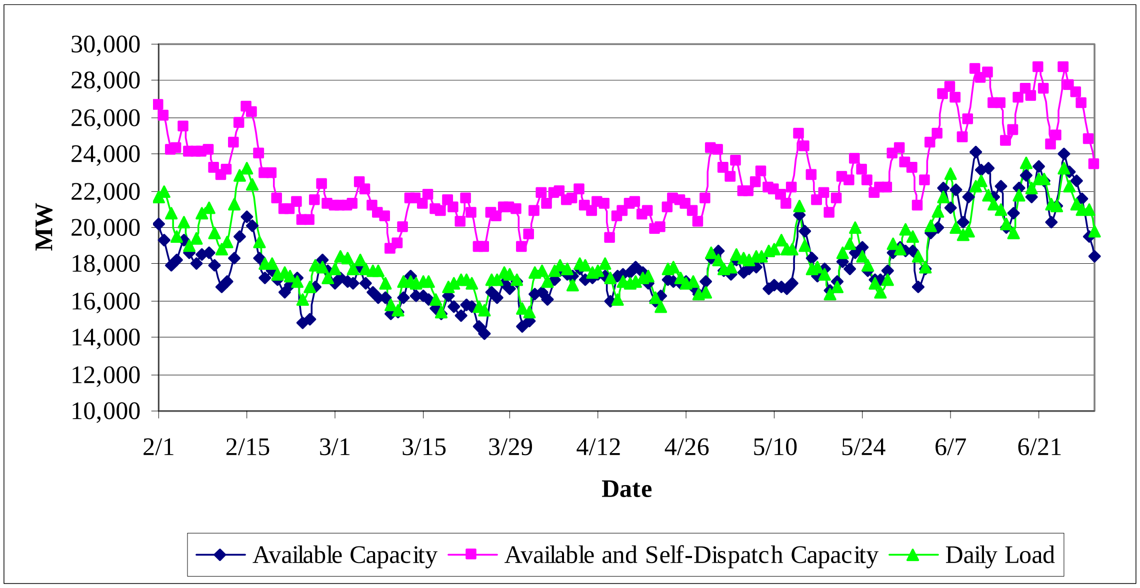
Table Eight

Percent of Total Capacity Made Available
to the EIS Market by Month and for the Quarter

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%
Average	18,038	22,819	79%

1) Available Capacity represents the sum of the Resource-Plan maximum for all Available generating units.
2) Available and Self-Dispatch Capacity represents the sum of the Resource-Plan maximum for all Available and Self-Dispatched generating units.
3) SPP-Wide Availability is Available Capacity divided by Available and Self-Dispatch Capacity.
4) Resources are not included if their status is Manual, Supplemental, or Unavailable.
5) Average is a weighted average.

Figure Nine
Capacity Made Available
Compared to Load in the SPP Footprint



1) Daily Load is the average of the hourly SPP load values for each day.
2) Available Capacity represents the sum of the Resource-Plan maximum for all Available generating units.
3) Available and Self-Dispatch Capacity represents the sum of the Resource-Plan maximum for all Available and Self-Dispatched generating units.
4) Resources are not included if their status is Manual, Supplemental, or Unavailable.
5) For the quarter, the available capacity could meet an average of 97.1% of the daily load.

Table Nine

Dispatchable Range of Capacity Made
Available to the EIS Market by Month and for the Quarter

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%
Average	18,038	8,541	47%

1) Available Capacity represents the sum of the Resource-Plan max for all Available generating units.
2) The Dispatchable Capacity is calculated using the Resource Plan and reserve designation. The upper level of the Dispatchable Capacity is equal to Maximum Economic Limit which is the Resource-Plan maximum minus Regulation Up and reserve services. The lower level of the Dispatchable Capacity is equal to the Minimum Economic Limit which is the Resource-Plan minimum plus Regulation Down service.
3) Percent Dispatchable is the Dispatchable Capacity divided by the Available Capacity.
4) Average is a weighted average.

IV. TRANSMISSION CONGESTION

Table Ten

Price Divergence as a
Rough Indicator of Transmission Congestion

Month	% of Hours with Price Divergence			Average On-Peak LIP without Congestion	Average On-Peak LIP with Congestion
	Off-Peak	On-Peak	Total		
February	56%	78%	66%	$51.51	$68.77
March	62%	69%	66%	$52.63	$53.38
April	54%	51%	52%	$56.03	$57.59
May	35%	43%	39%	$53.81	$64.20
June	90%	95%	92%	$45.63	$65.20
Quarter	59%	67%	63%	$53.64	$62.57

1) All prices are load-weighted and are per MWh.
2) LIPs diverge across locations only when congestion occurs. Congestion in a single 5-minute interval will result in price divergence being reported for that hour for this table.
3) The percentages represented here are out of the hours in that period (16 for On-Peak and 8 for Off-Peak during weekdays and 24 hours for Off-Peak during the weekend and NERC Holidays). For example, 4 hours of peak congestion would show 25%.

Table Eleven

Transmission Congestion Summary by Flowgate (Top 15) for the Quarter

Flowgate Name	Control Area	Count of Congested Intervals	Count of Binding Intervals	Count of Violated Intervals
SPP to SPS Ties	SPP-SPS	6,819	6,644	175
Jeffrey to Summit*	WR	5,213	5,113	100
SPS North-South	SPS	3,753	3,656	97
Lone Oak to Sardis	CSWS	3,461	2,548	913
Flintcreek to Tontitown	CSWS	1,413	492	921
Creswell to Newkirk / Kildare	WR-OKGE	908	865	43
Stilwell to Peculiar*	KCPL	815	536	279
Flintcreek to Tontitown*	CSWS	765	89	676
Okmulgee to Henryetta*	CSWS	473	462	11
Atlas Junction to Carthage	EDE-SPA	428	385	43
Swissvale Transformer	WR	420	400	20
S. Philips to W. McPherson	WR	405	392	13
Judson Large to Greensburg	WPEK	362	240	122
Valiant Transformer	CSWS	310	159	151
Shamrock Transformer	CSWS	302	270	32

* Indicates temporary flowgates. To get the names we matched the NERC TLRs to the SPP TLRs. The Jeffrey to Summit* and Flintcreek to Tontitown* flowgate names include two temporary flowgates.

1) Count of Congested Intervals is the count of intervals in which the flowgate was congested during the quarter. The table is sorted in descending order by this column.
2) Count of Binding Intervals is the count of intervals in which the flowgate limit was binding during the quarter.
3) Count of Violating Intervals is the count of intervals in which the flowgate limit was violated during the quarter.
4) A Flowgate-Interval is defined as one flowgate per five minute interval. The total number of Flowgate-Intervals in the quarter is equal to the number of flowgates multiplied by the number of intervals in the quarter (12*24*(28+31+30+31+30)).

Table Twelve

Transmission Congestion Summary
by Corridor for the Quarter

Transmission Corridor / Load Center	Count of Congested Intervals	Count of Binding Intervals	Count of Violated Intervals
SPS	10,577	10,301	276
Kansas East - West	5,685	5,557	128
Texas - Oklahoma East	4,045	2,939	1,106
Arkansas West - East	2,484	713	1,771
Kansas City	1,354	1,027	327
Wichita - Oklahoma City	1,134	1,074	60
Tulsa - Kansas City	563	511	52
South of Tulsa	559	546	13
Tulsa	222	203	19

1) Transmission Corridor/Load Center lists the major transmission corridors and load centers in SPP.
2) Count of Congested Intervals is the total count of congested flowgate intervals in each corridor or load center. That is, when two flowgates in the same transmission corridor or load center were constrained simultaneously – this is measured as two congested intervals. The table is sorted in descending order by this column.
3) Count of Binding Intervals is the total count of binding flowgate intervals.
4) Count of Violated Intervals is the total count of violated flowgate intervals.

Table Thirteen

Top 15 Congested Flowgates by Month and for the Quarter

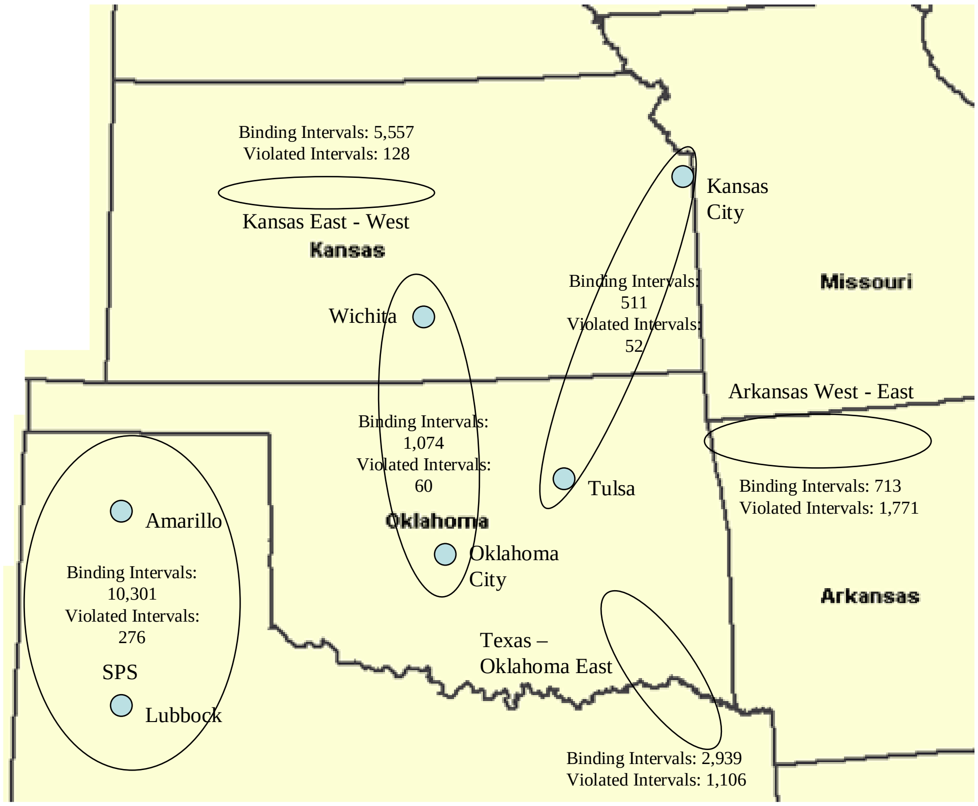
Flowgate Name	Corridor / Load Center	February	March	April	May	June	Quarter
SPP to SPS Ties	SPS	1,812	418	1,343	801	2,445	6,819
Jeffrey to Summit*	Kansas East - West					5,213	5,213
SPS North-South	SPS	459	694	1,596	312	692	3,753
Lone Oak to Sardis	Texas - Oklahoma East		3,046	415			3,461
Flintcreek to Tontitown	Arkansas West - East	824	125		26	438	1,413
Creswell to Newkirk / Kildare	Wichita - Oklahoma City	7	37	58	70	736	908
Stilwell to Peculiar*	Kansas City	705	110				815
Flintcreek to Tontitown*	Arkansas West - East	670			92	3	765
Okmulgee to Henryetta*	South of Tulsa		5	5		463	473
Atlas Junction to Carthage	Other	399		29			428
Swissvale Transformer	Kansas City		73	219	36	92	420
S. Philips to W. McPherson	Kansas East - West		339		8	58	405
Judson Large to Greensburg	Other	211	11	70	17	53	362
Valiant Transformer	Texas - Oklahoma East	231		79			310
Shamrock Transformer	Other					302	302

* Indicates temporary flowgates. To get the names we matched the NERC TLRs to the SPP TLRs. The Jeffrey to Summit* and Flintcreek to Tontitown* flowgate names include two temporary flowgates.

1) This table shows the number of congested intervals for each month of the quarter for the 15 most congested flowgates of the quarter.

Figure Ten

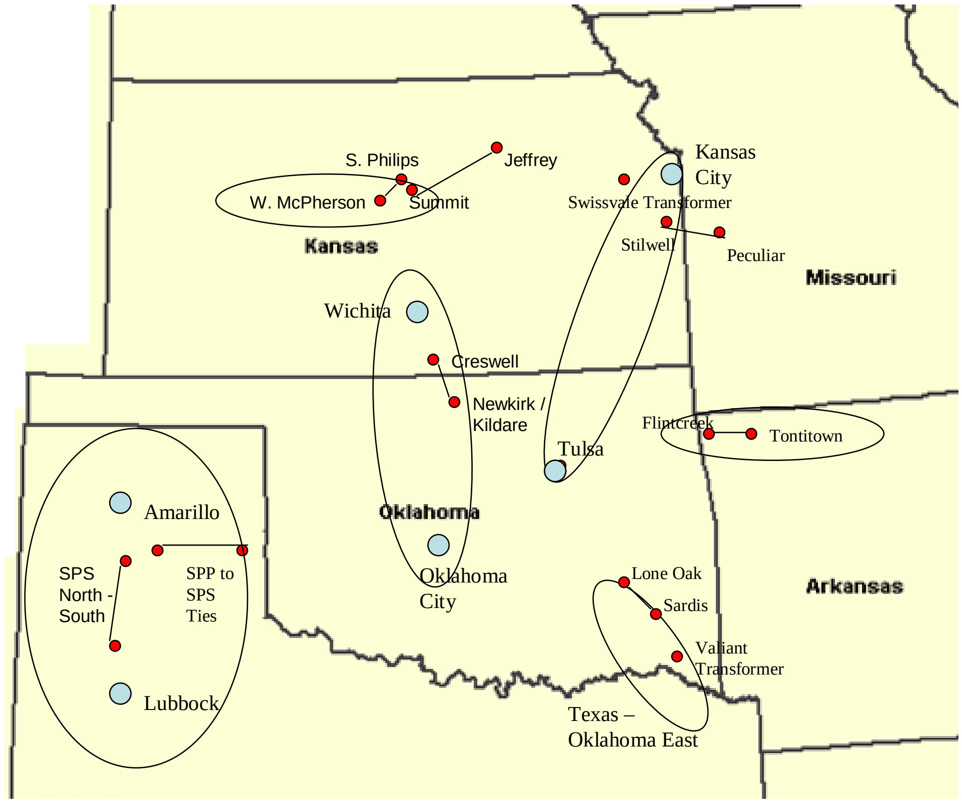
Transmission Congestion Map Summary
by Transmission Corridor for the Quarter



1) This figure above illustrates the graphical locations of the transmission corridors and load centers. Also shown is the total number of binding and violated flowgate intervals within each transmission corridor or load center.
2) Note: The Kansas City load center had 1,027 binding intervals and 327 violated intervals. The South of Tulsa area had 546 binding intervals and 13 violated intervals. The Tulsa load center had 203 binding intervals and 19 violated intervals.

Figure Eleven

Transmission Congestion Map Summary
by Flowgate for the Quarter



1) The figure above shows the location of some of the most congested flowgates for the quarter.

Table Fourteen
Congestion Resolution:
Percent Achieved by EIS Market

Month	EI Curtail Impact MWh	CAT Curtail Impact MWh	IDC Curtail Impact MWh	Total	Share Resolved By Market
February	123,081	5,898	3,525	132,504	92.9%
March	63,151	2,835	3,269	69,256	91.2%
April	41,811	5,617	1,698	49,125	85.1%
May	44,805	1,825	3,455	50,085	89.5%
June	111,353	19,628	5,286	136,267	81.7%
Quarter	384,202	35,802	17,233	437,237	87.9%

1) EI Curtail Impact MWh is the hourly amount of Energy Imbalance re-dispatch to unload all constrained flowgates.
2) CAT Curtail Impact MWh is the expected relief to be provided by curtailments determined with SPP's Curtailment Adjustment Tool (CAT).
3) IDC Curtail Impact MWh is the expected relief to be provided by curtailments determined by NERC's Interchange Distribution Calculator (IDC).
4) Total equals the sum of the previous three columns.
5) Share Resolved by Market equals EI Curtail Impact MWh divided by Total MWh Curtailments.
6) We note that in the filing to the FERC, the column marked "SPP Market Flow Relief Request MWh" is expected to, but does not, equal the sum of the EI Curtail Impact MWh plus CAT Curtail Impact MWh.

V. MARKET POWER MEASUREMENT AND MITIGATION

Table Fifteen
Effect of 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	0.14%	13.83%	0.0005%
March	0.04%	14.82%	0.0006%
April	0.01%	11.32%	0.0000%
May	0.00%	12.63%	0.0000%
June	0.00%	23.56%	0.0317%
Quarter	0.04%	15.24%	0.0066%

1) The FERC Offer Cap was $400/MWh for February through April and $1000/MWh in May and June. If the $400/MWh was used for May and June the value for the Percent of Resource Intervals Dispatched with Offer Near FERC Cap would have been 0.03% for both months.
2) Percent of Resource Intervals Dispatched with Offer Near FERC Cap represents the percentage of all resource intervals where a resource was dispatched when its offer price was within 5% of the FERC Offer Cap.
3) Percent of Resource Intervals with SPP Cap Imposed represents the percentage of all resource intervals that SPP's cap was actively imposed on a resource -- whether the resource's offer curve was truncated or not.
4) Percent of Resource Intervals with SPP Cap Imposed and Dispatched Near SPP Cap represents the percentage of the time the SPP Offer Cap was imposed on a resource and the resource was dispatched when its offer was within 5% of the SPP Offer Cap.

Table Sixteen

Shares of EIS Market Sales for all Market Participants (anonymous, ranked)

Market Participant	Market Share of Sales (February)	Market Share of Sales (March)	Market Share of Sales (April)	Market Share of Sales (May)	Market Share of Sales (June)	Market Share of Sales (Quarter)
1	16.4%	14.0%	14.8%	18.8%	25.4%	18.4%
2	10.7%	17.1%	14.2%	15.5%	17.3%	15.2%
3	19.1%	15.6%	16.5%	14.8%	10.6%	15.0%
4	17.0%	15.7%	12.1%	12.4%	11.7%	13.6%
5	3.9%	5.9%	6.2%	8.5%	7.6%	6.5%
6	7.0%	8.2%	9.7%	1.7%	4.8%	6.1%
7	7.8%	5.4%	7.0%	2.9%	3.0%	5.0%
8	5.7%	2.9%	3.4%	4.4%	3.7%	4.0%
9	0.9%	1.6%	2.5%	7.7%	5.8%	3.9%
10	3.4%	2.4%	2.4%	2.0%	2.1%	2.4%
11	1.6%	1.7%	3.0%	3.4%	1.2%	2.1%
12	1.6%	2.6%	1.8%	1.7%	1.5%	1.8%
13	1.7%	1.9%	1.4%	0.8%	1.1%	1.4%
14	0.7%	1.7%	1.2%	1.3%	0.9%	1.2%
15	1.0%	0.9%	1.2%	1.4%	1.1%	1.1%
16	0.3%	0.2%	1.6%	1.4%	0.7%	0.8%
17	0.4%	0.4%	0.4%	0.6%	0.8%	0.5%
18	0.7%	0.7%	0.3%	0.4%	0.5%	0.5%
19	0.3%	1.0%	0.4%	0.3%	0.3%	0.4%
20	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%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1) A sale is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled.
2) Market Share of Sales is the percentage of total MWh sold.
3) Initial Settlement values were used because Final Settlement statements were not available for all months.

Table Seventeen

Shares of Capacity Made Available at the
Peak Hour of the Month and the Quarter (anonymous, ranked)

Market Participant	February	March	April	May	June	Quarter
1	26.7%	27.8%	26.9%	25.3%	26.0%	26.0%
3	11.6%	12.4%	16.2%	15.5%	16.2%	16.2%
2	21.2%	20.3%	15.2%	15.1%	15.4%	15.4%
4	12.4%	15.4%	12.7%	12.6%	13.2%	13.2%
5	4.7%	5.8%	8.4%	8.2%	5.5%	5.5%
6	2.5%	3.1%	2.6%	4.5%	4.3%	4.3%
8	3.9%	1.5%	2.0%	3.4%	3.8%	3.8%
9	3.5%	2.8%	2.6%	2.2%	3.1%	3.1%
10	3.0%	1.1%	1.3%	1.3%	2.9%	2.9%
7	2.3%	2.5%	4.6%	3.7%	2.8%	2.8%
11	1.6%	0.0%	2.4%	2.1%	2.5%	2.5%
13	2.2%	2.5%	0.0%	1.2%	1.8%	1.8%
12	1.3%	1.8%	1.7%	1.7%	1.4%	1.4%
14	1.1%	1.3%	1.2%	1.0%	1.0%	1.0%
15	0.0%	0.0%	2.3%	2.1%	0.0%	0.0%
16	1.7%	1.6%	0.0%	0.0%	0.0%	0.0%
17	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1) The highest peak load in February occurred on February 16th at hour ending 8:00.
2) The highest peak load in March occurred on March 5th at hour ending 8:00.
3) The highest peak load in April occurred on April 30th at hour ending 17:00.
4) The highest peak load in May occurred on May 14th at hour ending 17:00.
5) The highest peak load in June occurred on June 19th at hour ending 17:00.
6) The highest peak load for the quarter occurred in June on June 19th at hour ending 17:00.
7) % of Available Capacity is the market participant's share of the available capacity during that hour.

VI. FUEL TYPE

Table Eighteen

Generation by Fuel Type by Month and for the Quarter

Fuel Type	February	March	April	May	June	Quarter
Coal	67.4%	65.3%	62.4%	64.7%	64.6%	64.9%
Gas/Oil	23.0%	23.8%	26.4%	25.0%	26.9%	25.1%
Nuclear	6.0%	6.7%	6.7%	6.3%	5.5%	6.2%
Wind	2.6%	3.1%	3.1%	2.4%	1.7%	2.5%
Hydro	0.6%	0.8%	1.2%	1.5%	1.2%	1.1%
Other	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1) Other includes resources that we were unable to assign a fuel type and resources that use other fuel types not listed in the table.
2) For the purposes of this report, Gas and Oil were combined into one category.
3) Due to data limitations some assumptions were necessary in assigning resources fuel types. Therefore these numbers should be seen as an approximation.
4) Looking at only Available Resources - Coal accounts for roughly 70% and Gas accounts for approximately 30% of the fuel mix.
5) Negative values for pump storage were removed for this calculation.

Table Nineteen

Generation at the Margin by Month and for the Quarter

Fuel Type	February	March	April	May	June	Quarter
Gas/Oil	71.5%	72.1%	84.0%	80.7%	70.1%	75.3%
Coal	28.5%	27.9%	16.0%	19.2%	29.5%	24.6%
Other	0.0%	0.0%	0.0%	0.0%	0.4%	0.1%
Hydro	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%

1) Other includes resources that we were not able to assign a fuel type and resources that use other fuel types not listed in the table.
2) For the purposes of this report, Gas and Oil were combined into one category.
3) Due to data limitations some assumptions were necessary in assigning resources fuel types. Therefore these numbers should be seen as an approximation.
4) For the purposes of this report, a marginal resource was defined as a resource that was available to the market and had an offer price within $0.20 of its administered price.

MEMORANDUM

July 20, 2007

TO: SPP Board of Directors

FROM: Craig Roach

SUBJECT: Approved Rules for External Generators

INTRODUCTION

I understand that, during the Board of Directors meeting on June 21, the Board considered and approved the recommendation to adopt PRR 137a as the approach to implement External Generator participation in the SPP Energy Imbalance Service (EIS) Market. And, as part of the discussion, the Board requested that Boston Pacific consider the following question:

> Is the approach chosen by the adoption of PRR 137a unduly burdensome or discriminatory to any market participant sector(s) as compared to the other approach considered and declined by the MWG and MOPC?

At the outset, we should state that we would prefer to have more competitors and a greater diversity of competitors – diverse locations, technologies, and fuels -- in the EIS Market because we believe that benefits consumers. For this reason we would like to see the rules put in place to allow External Generators to compete. As FERC noted in its Order, the power from External Generators might find its way into the EIS Market today, but only if an Internal Balancing Authority accommodates the transaction. The most likely accommodation would be that the Internal Balancing Authority would sign a bilateral contract with the External Generator, use that power to displace (free up) its own resources, and then bid its freed-up resources into the EIS Market. The problem with the current situation is that it requires accommodation from a potential competitor – the Internal Balancing Authority – and that accommodation may be withheld. Going forward we believe it would be beneficial for SPP to establish a transparent way for an External Generator to participate directly in the EIS or any future SPP administered Market.

Also at the outset, we should state our understanding of the term "unduly discriminatory" used in the Board's question. It would be unduly discriminatory to treat two similarly-situated Market Participants in fundamentally different ways. In the present context, the two types of Market Participants that we have to compare are Internal Generators – those within the SPP footprint – and External

Generators – those outside the SPP footprint. Internal and External Generators are not similarly situated in all respects – most notably in location – so they can be treated differently without being unduly discriminatory. For example, in competitive solicitations we monitor elsewhere, it is common for a bidder outside the relevant Balancing Authority to be required to buy and show evidence of transmission service to the border of the Balancing Authority. In other words, it is not discriminatory to treat Internal and External Generators differently if the difference can be justified by the facts.

THE APPROVED PSEUDO-TIE METHOD

Based on a review of meeting minutes from MOPC, MWG, and ORWG, we understand that the discussion narrowed the range of options on how to accommodate External Generators to two methodologies– the Pseudo-Tie Methodology and the Dynamically Dispatched Methodology. We further understand that the Pseudo-Tie Method was recommended because the Dynamically Dispatched Method would take considerable time to implement, would not be in place in the near term (as FERC wants it to be), and it also would require expensive software system changes.

As we see it, the heart of the Pseudo-Tie Method is to assume, artificially, that the External Generator is actually generating or delivering its power at a point within the SPP footprint. To give this assumption some reality, the External Generator must show that it has secured transmission service to get its power to the SPP footprint. As noted above, there is nothing unduly discriminatory in requiring such transmission service. The controversy appears to arise because the requirement is that *firm* transmission service be purchased by the External Generator, as opposed to *non-firm* service. Those proposing the requirement for a firm transmission path to the SPP footprint believe that it places the External Generator on a more comparable basis to Internal Generators since generators within the SPP Market footprint, by virtue of their direct connection, already have a firm path to the SPP footprint.

Related importantly to the transmission service required under the Pseudo-Tie Method is the provision of reserve energy if and when the External Generator either fails to generate power or its transmission service is curtailed. As we understand it, members of the Reserve Sharing Group (RSG) will provide the energy reserves for External Generators; we presume the same rules (see Attachment AK to the SPP Tariff) will apply to both Internal and External Generators.

Given this use of RSG energy reserves, what does the requirement for *firm* transmission service achieve? In our opinion, what the firm service does is to reduce the chances of curtailment of the External Generator due to the curtailment of transmission service *outside* the SPP footprint. That is, it reduces the probability of a loss of power from the External Generator due to curtailment of transmission; firm transmission service is a higher priority than non-firm, and firm service will be curtailed rarely. In addition, it is asserted that the use of RSG energy reserves can be allowed if and only if the transmission service is firm; otherwise a change in SPP Criteria is said to be required.

To address the concern over the requirement for firm transmission service, the Pseudo-Tie Method includes an alternative: an External Generator may use *non-firm* transmission service if it can get the External Balancing Authority to agree to limit the curtailments associated with the resource. The restrictions will require the External Balancing Authority to explicitly agree that the only conditions under which it will call for an immediate curtailment of the pseudo tie is in the case of an Interconnection Reliability Operating Limit (IROL) violation. In spite of the fact that these limitations may naturally occur under their normal business practices, the External Balancing Authority will likely have little incentive to agree to this requirement. It is good to have alternatives, but we think this one is unlikely to be used unless the External Generator itself is actually operating its own Balancing Authority.

The Pseudo-Tie Method also sets limits on the amount of External Generation that can be accommodated; the limits are by Balancing Authority and for SPP as a whole. The purpose of the limits is to give further assurance that sufficient reserves are in place to ensure reliability.

CONCLUSIONS

We do not see any reason to judge the Pseudo-Tie Method to be unduly discriminatory. Again, Internal and External Generators are not similarly situated with respect to location so requiring the External Generator to secure transmission service to the SPP is not unduly discriminatory. Neither are the Internal and External Generators similarly situated in terms of the probability of needing energy reserves from the RSG; External Generators have an additional potential need for RSG energy reserves due to the curtailment of external transmission service. The difference in the probability of needing energy reserves appears to be a reasonable justification for the requirement for firm transmission service.

In addition, we do not see the restrictions on the amount of External Generation as unduly discriminatory and they may be a necessary incremental step to take during the startup phase of the participation by External Generator. We do believe the ORWG should continue to review and perhaps refine these restrictions. Specifically they should consider whether or not these restrictions could take into consideration whether or not the participating External Generators are likely to experience simultaneous transmission related curtailments.

However, while we do not see undue discrimination, we also do not see any reason to believe the Pseudo-Tie Method will be especially effective in actually attracting External Generators to compete.[1] (FERC may actually be more concerned with effectiveness than with just the issue of undue discrimination.) The purchase of firm transmission service may be the more likely option of the two offered to be used by an External Generator, but that purchase will be expensive. And the method still requires accommodation from potential competitors; that is, both the Internal and External Balancing Authorities must sign the Agreement in Attachment AO.

With the intent of making the Pseudo-Tie Method somewhat more effective, we suggest a third alternative option to include: allow an External Generator to purchase *non-firm* transmission service if it gets the agreement from an *Internal* Balancing Authority to provide energy reserves under Attachment AK to cover not only an outage of its power plant, but also for the curtailment of its non-firm external transmission service. While this option still requires accommodation by a potential competitor, it is a potential competitor under the jurisdiction of the SPP RTO. If the creation of this third option requires an amendment to SPP Criteria, then a narrowly crafted amendment should be proposed.

We hope this is helpful and look forward to hearing any comments and questions at the Board Meeting on July 24.

---

[1] Another concern we have heard, in the context of effectiveness, is that the Pseudo-Tie Method will attract only those External Generators who want to make a long-term shift to sell to the SPP EIS Market. That is, it does not accommodate the External Generator who wants to make sales from time to time – that is, it does not accommodate opportunity sales.