AN ASSESSMENT OF PRICE VOLATILITY IN RECENT DEPLOYMENT TESTS FOR THE SPP EIS MARKET

PRESENTED TO

THE SPP BOARD OF DIRECTORS AND MEMBERS COMMITTEE

PRESENTED BY

BOSTON PACIFIC COMPANY, INC.
EXTERNAL MARKET MONITOR FOR THE SPP RTO

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I. INTRODUCTION AND SUMMARY

A. Introduction

SPP has been running tests of the software systems and procedures for its Energy Imbalance Services (EIS) Market with the intent of assuring readiness for market start as soon as possible.[1] Market Participants also have been actively engaged in these tests to assure the readiness of the systems each has built to interface with the EIS Market.

In the EIS Market, power plants (Resources) are dispatched (deployed) every five minutes to assure the lowest cost Resources are used to meet customer needs (load) in each time period. Each of these five-minute periods is referred to as a deployment interval. During some of the tests, in some of these five-minute deployment intervals, the prices for certain geographic locations in the EIS Market – called Locational Imbalance Prices or LIPs – reached very high or very low (negative) levels. Movement of LIPs to such extremes has been termed "price volatility."

The purpose of this report is to provide an independent assessment of the cause or causes of LIP volatility. As background, we first describe the theory of LIP determination in the SPP EIS Market and also identify real world complexities that might drive LIPs to extremes. Next we diagnose the price extremes actually seen in a number of deployment tests. We then give the LIP volatility seen during the deployment tests some context by examining other RTO markets. We conclude with some recommendations on what might be done to address LIP volatility.

We very much appreciate the significant input we have received from Market Participants and SPP Staff. At the outset, we reviewed our scope of work in a teleconference with the Market Working Group (MWG). As we completed diagnoses of deployment intervals we sought and received feedback on draft diagnoses from the full range of Market Participants and from SPP Staff.[2] In addition, several Market Participants generously waived confidentiality concerns to allow the diagnoses to be made public herein. Finally a full rough draft of this report was distributed to gain initial feedback from a range of Market Participants and SPP Staff.

B. Summary

1. Causes of Price Volatility During the Deployment Tests

Table One provides a sample of data from our diagnoses of price extremes in three of the deployment tests. We refer to this table at various points in this summary. For perspective, note that for the three deployment tests in the Table, out of a total of 324 deployment intervals, we found price extremes in thirteen of the intervals.

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[1] The most recent scheduled start date was November 1, 2006. That has been pushed back until at least December 1, 2006.
[2] Special thanks to Rick Running of SPP Staff for his help, most notably his computer modeling work.

TABLE ONE
SAMPLE OF DATA FROM DIAGNOSES OF PRICE EXTREMES

Full Deployment Test Statistics			Statistics for One Diagnosed Interval						
Date (Time CPT)	**Total Intervals**	**Intervals with Price Extremes**	**Interval (Ending CPT)**	**Constraint Name**	**Violation Amount (MW)**	**LIP Min. ($/MWh)**	**LIP Max. ($/MWh)**	**SMP ($/MWh)**	**Shadow Price ($/MWh)**
Sep. 26-27 (9pm - 5am)	96	2	11:55 p.m.	SPP to SPS Ties	6	$ (76.04)	$ 20,005.44	$ 3,427.01	$ (19,995.94)
Sep. 13 (10am - 2pm)	48	6	1:40 p.m.	Flint Creek	10	$ (1,584.78)	$ 1,788.59	$ 268.44	$ (19,380.05)
Oct. 12 (5am - 8pm)	180	5	10:05 a.m.	Oneta to Broken Arrow	6	$ (1,883.23)	$ 3,203.59	$ 315.01	$ (19,984.00)

At the outset it is important to note that all of the extreme prices we diagnosed occurred during deployment intervals in which a transmission constraint was violated. That is, these extreme prices occurred when power flowing over a grouping of transmission facilities (a flowgate) exceeded the effective limit of that flowgate; for example, 103 MW might be flowing over a flowgate with an effective limit of just 100 MW. These are not just cases in which a flowgate is used up to its effective limit; we would refer to that as a *binding* constraint, not a *violated* constraint.

Note, too, that in all the cases we diagnosed, the extent to which the constraint was violated was very small; all involved 10 or fewer MW. In this sense, these violations and the resulting price extremes are on something of a "hair trigger." It is important to recognize that the effective limits on flowgates reflect several objectives in system operation, but we do not understand them to be an absolute physical limit on use of the transmission equipment. It seems reasonable that SPP operators would have some flexibility to re-set the effective limits on flowgates to resolve a constraint violation and avoid price extremes.

Also, in all these cases there always were limited options available to SPP for resolving the constraints by either (a) increasing the level of generation from Resources on the importing side of the constraint or (b) decreasing the level of generation from Resources on the exporting side of the constraint. Options were limited in three ways. First, some Resources that would have had the largest effect on the flowgate were self-dispatched; that is, they were not offered in the EIS Market so SPP could not re-dispatch them to relieve the constraint. Second, some of the Resources offered into the EIS Market were already dispatched at their maximums and could not be increased more to resolve the constraint. Third, the level of generation from some of the Resources offered into the EIS Market could not be increased or decreased fast enough to resolve the constraint in one or a few deployment intervals; that is, the "ramp rates" offered were not high enough to allow the needed increase or decrease in generation during one deployment interval.

Finally, the price extremes are driven significantly by the high level of "Penalty Factors" used by SPP. Penalty Factors are something required by the optimization software used for economic dispatch. To see this, consider that the dispatch software starts with the objective to minimize the cost of electricity to serve customers in the upcoming deployment interval. However, that objective must be pursued with recognition of certain constraints. Transmission constraints are among the most important. Without Penalty Factors, at times when the objective of cost minimization simply cannot be achieved without violating a constraint, the software would simply come back to SPP and say it has no answer – it could not tell SPP how to optimally dispatch the available Resources. To avoid this situation, SPP set a price at which the software may violate a constraint – that price for violating a constraint is called a Penalty Factor. The Penalty Factor for violating a transmission constraint is set at $20,000/MW in the SPP RTO.

To see how the Penalty Factor drives prices so high, it is important to be clear on how LIPs are calculated. A LIP is made up of two components. The first is the System Marginal Price (SMP) which is the estimated cost of providing one more MWh to the

SPP footprint. At any one time, all Resources have the same SMP and, if there are no binding (or violated) constraints, the SMP is the single LIP applicable to all of the Resources in the SPP footprint. The second component of a LIP applies when there is a constraint which is binding (or violated) and this component will vary by the location of a Resource. This second component of a LIP equals the Shadow Price of any binding or violated constraint times the shift factor for that Resource. For transmission constraints, the Shadow Price equals the estimated cost savings if the transmission constraint were to be relieved by some small amount. The shift factor tells us the extent to which generation from a particular Resource impacts the flowgate – if generation is 100 MW and 50 MW of that flows over the flowgate, then the shift factor for that Resource is 50%.

A Penalty Factor has such a significant effect on LIPs because, when a transmission constraint is *violated*, the Shadow Price is initially set equal to the Penalty Factor of $20,000/MW. There is a process called Price Administration which is intended to assure that the LIPs used for settlement are not influenced by the Penalty Factors. However, a look at the Shadow Prices in Table One shows that Price Administration does little in this regard – the Price Administered Shadow Prices are still very close to the $20,000/MW Penalty Factor.

We should add one other point about what does *not* cause price extremes: the price extremes we diagnosed are not caused by Market Participants bidding high prices. In all our diagnoses, the LIPs far exceeded any of the bid prices.

2. Recommendations to Address Price Volatility

Price extremes do not always indicate a defect in an electricity spot market. No matter how extreme, if spot prices are accurately signaling market conditions, they are doing their job. In particular, locational prices like LIPs are meant to reveal transmission constraints, which in turn signal the need for new transmission investment. In this sense, the extreme LIPs seen in the deployment test are just doing the job they are designed to do. However, we believe the LIPs are doing their job with unnecessary exuberance. We recommend three actions to mitigate (not eliminate) price extremes (price volatility).

First, the Penalty Factors for a violation of a transmission constraint should be lowered. While Penalty Factors may be an analytic necessity, the actual dollar value of Penalty Factors is a matter of judgment. The $20,000/MW used at present is causing some very extreme prices and we have not seen any written justification for that level. To verify that the Penalty Factor is driving LIP extremes, we asked SPP to re-run the dispatch model for the deployment test of September 26, interval ending at 11:55 p.m. The only change was that the Penalty Factor was set alternatively to $1,000/MW, $10,000/MW, and $30,000/MW. In each run, the shadow price and the maximum LIP are almost identical to the Penalty Factor. There is a danger of using too low of a Penalty Factor in the sense that there may be more violations or violations of greater magnitude. One approach to move forward would be to lower the Penalty Factor for the market start and to report on its consequences over the first three- and six-month periods.

Second, SPP operators should have the flexibility to re-set effective limits on flowgates to avoid having very small constraint violations cause widespread price extremes. They may already have this flexibility, but, if not, business practices should be changed so they do. We see this flexibility being consistent with SPP's current practice of selling non-firm transmission service in excess of the effective limit. It also would be consistent with practices we understand New York ISO uses to address constraint violations.

Third, Market Participants should be committed to making a *voluntary* EIS Market work to the benefit of consumers. Price extremes can stand in the way of achieving that goal even if their actual impact on customer bills is mitigated. The commitment to a successful voluntary market should include Market Participants scheduling and offering (rather than self-dispatching) key Resources to the Market and also assuring reasonable ramp rates for those Resources. Again, re-running the dispatch model makes it clear that slightly higher ramp rates and changing status to scheduling and offering can mitigate price extremes.

II. BACKGROUND ON PRICING IN THE EIS MARKET

A. How Are Prices Determined?

To diagnose the cause or causes of price extremes, it is important to have some sense of how prices (the LIPs) are determined in the EIS Market. We first offer an accurate but simple explanation. We then add some of the complexity which will help diagnose price volatility.

1. An accurate, but simple explanation

The simplest view of price determination is generally accurate. We can start with the case in which there are no transmission constraints; this means SPP can pick suppliers from anywhere in the footprint to serve customer needs. Envision ten suppliers offering into the market and each has a single price. To keep it simple, think of the first and lowest cost of the ten suppliers offering at $10 per megawatt hour (MWh), the next supplier offering at $20/MWh, the third at $30/MWh, and so on with the tenth supplier offering at $100/MWh. Let's say the market needs six MWh in one of the five-minute deployment intervals so SPP picks the lowest six price offers; that is, the six with price offers ranging from $10/MWh to $60/MWh. The price (the LIP) throughout the SPP footprint would be same – $60/MWh would be paid to all six winning suppliers.

Since all of the price events we will diagnose reflect real or simulated transmission congestion, it is important to give a sense of how transmission congestion affects price determination. Let's stick with our simple example of ten suppliers. Transmission congestion, in effect, splits the SPP footprint into separate sub markets. SPP can no longer simply choose the cheapest supplier from across the footprint. Assume for our simple example that the market is split into two separate markets by a transmission constraint, and we need three MWh in each of the two markets. Assume further that, in one market, SPP can pick the three lowest cost suppliers to serve the three MWh needed within that market. In this market, then, the three suppliers chosen would be those offering $10/MWh, $20/MWh, and $30/MWh, and all three suppliers would be paid the $30/MWh price. Assume further that the transmission constraint has blocked off from the second market the suppliers with the $40/MWh and $50/MWh offers. That means the second market must turn to the $60/MWh, $70/MWh and $80/MWh offers to serve the needs in this second market. Therefore, with the transmission congestion, different prices will be determined for each of the two markets; a $30/MWh LIP for one market and an $80/MWh LIP for the second market (the market suffering from the transmission congestion).

This is what transmission congestion does – it balkanizes the SPP footprint into separate markets each with its own LIP. LIPs are higher in the constrained area and lower elsewhere.

2. The Actual Formula for LIP Calculation

While this simple view of price determination in the face of transmission congestion is good enough for a basic understanding of how spot markets should work, it is not good enough to understand the diagnosis of price extremes. To fully understand LIP volatility it is necessary to examine the actual formula used to calculate LIPs. The formula is provided below with a discussion of each of the elements after that.

LIP = System Marginal Price + (Shift Factor * Shadow Price)

System Marginal Price: The LIP reflects the cost of providing the *next* MWh, not the last MWh as in the simple story. This should not be a big deal in most cases; although in the example with the transmission constraint used above it would drive the LIP up by $10/MWh (to $40/MWh in the one market and to $90/MWh in the other.) What is more important is that the software makes the determination of a LIP more detailed than in the simple explanation. Specifically, the first of two components of any LIP is the System Marginal Price (SMP): it is the cost of providing the next MWh *in the SPP footprint* given the transmission constraint. If there are no transmission constraints, the LIP is simply equal to the SMP.

Shadow Price and Shift Factors: The second component of the LIP reflects the cost of the transmission constraint; or more precisely the value of relieving the constraint by some small amount. The value of relieving the constraint is generally that cheaper power can be used – so the value is reflected in the difference in LIPs on either side of the constraint. This value is called the "shadow price" of the constraint. The portion of the shadow price included in a LIP for a Resource at a particular location depends on the extent to which that Resource impacts the constrained transmission facility. The measure of that impact is called a "shift factor." If a Resource generates 10 MWh and 5 MWh of that impacts the relevant transmission facilities (the flowgate), then the shift factor is 50%.

In sum then, a LIP at any one location equals (a) the system marginal price (SMP) plus (b) the shift factor times the shadow price of the constraint.

Penalty Factors as the Shadow Price: When a transmission constant is truly violated – 105 MW is sent over a transmission facility (flowgate) said to have a limit of 100 MW – then the shadow price reflects something called a "penalty factor." The penalty factor is a judgment on the value of violating that constraint. Several RTO energy markets have them, but they vary in level. For SPP's EIS Market, the penalty factor for violating a transmission constraint is $20,000/MW. In the event of a violation, the shadow price is initially set equal to the penalty factor and is then recalculated through a process called Price Administration. In general, the rules are that the revised shadow price does not reflect the penalty factor, and therefore, the penalty factor should not be paid by Market Participants. However, as illustrated with the extreme prices diagnosed here, the LIPs used in settlement after price administration still can be extreme.

3. Necessary complications for LIP determination

It is important to remember that the EIS Market is a voluntary market so Market Participants can choose the extent to which they want to be involved. If a Market Participant decides to not make its Resources available to the market, then the range of Resources that can be used to set the LIP is diminished. For example, if the $10/MWh Resource in the simple example above is not available to the market, the sixth cheapest Resource would result in a market clearing price of $70/MWh. There are multiple ways in which a Market Participant may chose to limit its Resource's availability, all of which have important implications for LIP volatility and all of which are allowed by the rules. The ways to limit availability are explained below.

Self-Dispatch: A Market Participant who self-dispatches is not available for deployment by SPP. A self-dispatched unit could be one of the least costly sources of generation in our simple explanation above, but SPP would not be able to call on it to serve customer needs.

Ramp Rate Limits: Even for those suppliers who are available for deployment, there are limits on how fast the supplier can ramp up the operation of its power plant to meet a change in customer needs. Suppliers literally state "ramp rates" that SPP must use as the pace (stated in MW per minute) at which SPP can move the level of operation from one level to the next. Market Participants can limit the degree to which their Resource is available for deployment by submitting a low ramp rate.

Dispatchable Range: Market Participants submit an operating maximum and operating minimum for each of their Resources. The market cannot dispatch a Resource above its maximum or below its minimum, and once again, these limits are set at the participant's discretion. The difference between the maximum and the minimum is the dispatchable range.[3] So even if a supplier designates its Resources available for deployment, the participant can in essence remove those Resources from the market by submitting a dispatchable range of zero (or near zero).

B. Who pays these prices?

It is important to know who might pay any volatile prices. To understand who pays, it is important to understand the two ways Market Participants can voluntarily participate in the EIS Market. The two ways are to *Self-Dispatch* and to *Offer and Schedule*.

Self-Dispatch: With Self-Dispatch, a Market Participant, in effect, hard wires the way in which it will serve its customer's needs. That is, the Market Participant

[3] Ancillary service requirements must also be taken into account.

says I have these customers, I will use these power plants (Resources) to generate electricity to serve them, and, therefore, I will need these transmission lines to get the power to them. To the extent everything goes precisely as planned, a Self-Dispatched Market Participant is not buying or selling in the EIS Market. Of course, things do not always go as planned. Customer needs may be higher than expected because temperatures rise. Generation may not be available because a power plant suffers an unplanned (forced) outage. Generally speaking, when things do not go as planned (as hard wired) the Market Participant must buy the extra power that it needs from the EIS Market. The difference between the hard-wired plan and reality is an *imbalance* and all Market Participants must fill these imbalances in the EIS Market.

Scheduling and Offering: With Scheduling and Offering, a Market Participant may more fully participate in the EIS Market. The Market Participant starts out with a hard-wired solution to serving its customers – that is what the schedules do. However, a Market Participant who Schedules and Offers says, if the SPP EIS Market has a lower cost supply for my customers than what I hard-wired, I will take it. With all Market Participants who Schedule and Offer, then, SPP puts aside hard-wired solutions (the schedules), and deploys all the Resources available to get the lowest cost supply. In this sense, then, the EIS Market can be more than just an imbalance energy market – it can be a full scale, centrally dispatched energy market as in some other RTOs like PJM. However, if supply in the EIS Market is not less costly than the hard-wired solution, these Market Participants will see the solution they scheduled being chosen by SPP as the best way to serve their customers. In this way, if EIS Market prices are too high, those who are Scheduled and Offered participate only to the same extent as those who Self-Dispatched – they buy in the EIS Market only to the extent reality differs from the hard-wired solution, only to the extent there is an imbalance. The schedule gives these Market Participants protection as a hedge against high EIS Market Prices.

III. DIAGNOSES OF ACTUAL PRICE EXTREMES

A. Diagnosis Number One

Date of Test: September 26, 2006 to September 27, 2006
Two Deployment Intervals: Ending 11:55 p.m. and ending at midnight
LIPs of Interest: Approximately $20,000/MWh in both intervals

1. Background on the Price Event

SPP conducted a deployment test for eight hours from 9 p.m. on September 26 to 5 a.m. on September 27 (CPT). With twelve five-minute intervals in each hour, the test covered ninety-six deployment intervals. In two of the ninety-six deployment intervals, the LIPs were extreme for one geographic area. Specifically, the LIPs for all Resources in the Southwest Public Service (SPS) area were around $20,000/MWh in the interval ending at 11:55 p.m. and the interval ending at midnight.

A real (not simulated) transmission constraint on the SPP into SPS flowgate played a significant role.[4] A Transmission Loading Relief (TLR) event was in place for 8.5 hours (8 p.m. to 4:30 a.m.) but no schedules were cut. Note also that, one of the reasons for the TLR was that the SPP to SPS flowgate capacity was reduced from approximately 450 MW to 78 MW due to an outage of another transmission line (a DC line from SPP to ERCOT).[5] At this low level of capacity (78 MW), the constraint was binding for sixty-eight of the ninety-six intervals; that is, power flow just met the capacity limit in those intervals. In all sixty-eight intervals, maximum LIPs in all locations within the SPP footprint were no higher than $65/MWh. In just two intervals, the SPP to SPS flowgate limit was violated, and it was in these two intervals that LIPs spiked to around $20,000/MWh.

2. Causes of the Price Event at 11:55 p.m.

Clearly, the violation of the transmission constraint is the immediate cause of the $20,000/MWh LIP for the deployment interval ending at 11:55 p.m. Therefore, it is important to diagnose the causes of the violation.

SPS had a Net Scheduled Interchange (NSI) of 285 MW in the intervals preceding the interval ending at 11:55 p.m. Included in this NSI is a scheduled sale of power over the DC ties to the West. This means that given all scheduled sales and power flows, a net of 285 MW were scheduled to leave the SPS area. At that NSI, the SPP to SPS flowgate was at its 78 MW limit; again, the flowgate constraint was binding, but not violated.

SPS intended to switch the power plants that were supporting that sale to the West. However, the power plant brought on to supply the sale was scheduled to increase

[4] It should be noted that the SPP to SPS ties are a unique flowgate in SPP. There is currently some discussion (see PRR 082) about modifying how this flowgate is modeled. A change in the modeling may or may not affect events such as those that happened during this test.
[5] The limit was decreased to maintain voltage stability.

(ramp up) its generation faster than the power plant it replaced was scheduled to decrease (ramp down) its generation. The impact was that the scheduled NSI (specifically the generation necessary to fulfill the obligation of the sale to the West) increased by 38 MW. The scheduled NSI went from 285 MW for the interval ending at 11:50 p.m. to 323 MW for the interval ending at 11:55 p.m. Note too, that changes in other generation or load added another 3 MW of need within the SPS area. Consequently, the total extra demand for the interval ending at 11:55 p.m. was 41 MW.

With this need for an additional 41 MW of generation for the interval ending at 11:55 p.m., SPP turned to the Resources within the SPS area. Of those Resources, eleven were available to the EIS Market and thirty-six were not available.[6] Of the eleven Resources available to the EIS Market, four were at their maximum capacity and one had a ramp rate of 0 MW/min. Therefore these five Resources were not available to supply any of the needed 41 MW. Among the remaining six Resources available to the Market, all six were limited by their ramp rates which varied from 0.5 MW/min to 1.5 MW/min.[7]

In total, these six Resources were available and could add 7 MW/min or a total of 35 MW in the five-minute deployment interval. This 35 MW fell short of the 41 MW needed so SPP turned to Resources outside the SPS area and tried to import 6 MW over the SPP to SPS flowgate. At that point, the flowgate capacity was exceeded by 6 MW – 84 MW were flowing which exceeds the 78 MW limit.

Note that this sequence of events could occur again. They should not be dismissed as an aberration. At the same time, the problem did not persist during this test; the problem was fixed on one interval as ramp capability was made available.

3. LIP Calculation

It is important to see how the LIP for the SPS Resources was calculated with the SPP to SPS flowgate limit actually violated. Recall that a LIP equals the System Marginal Price (SMP) plus the relevant shift factor times the Shadow Price. With respect to the SMP, all the Resources in the SPS area were constrained either by ramp rate or maximum capacity. For that reason, SPP had to look outside that area for the marginal Resources. All Resources outside the SPS area, however, would aggravate the constraint in the sense they would add to the flows over the flowgate. The only way to provide the marginal MW, without further violating the constraint, was to shift generation to a Resource that impacts the constraint less; that is, to switch some generation from a Resource with a higher shift factor for the SPP to SPS flowgate to one with a lower shift factor.

It is worth going through a calculation by hand to see how this approach to providing the marginal MW can drive this SMP so high. To illustrate, we will use the two Resources that were calculated to be the marginal units during the interval ending at

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[6] Xcel informed us that these eleven are all those equipped with Automatic Generation Control (AGC) and, therefore, capable of responding to SPP's dispatch instructions.
[7] Xcel informed us that these ramp rates were limited to protect against "oscillating dispatch instructions."

11:55.[8] Both Resources have positive shift factors for the SPP to SPS flowgate, but one is slightly higher than the other. The higher shift factor is 0.17082. This means 5.8541 MW of generation would have an impact of 1 MW on the flowgate. The lower shift factor is 0.17064; meaning 5.8603 MW would have a 1 MW impact on the flowgate.

Continuing with our calculation, the price offer from the Resource with the lower shift factor – the one we want to use for *increased* production – is $14.95/MWh which is higher than the price offer of $11.38/MWh for the Resource on which we will *decrease* production. If we generate 5.8603 MWh at $14.95/MWh, we spend $87.61 increasing generation at the lower-shift-factor Resource. However, we decrease production at the other Resource so we save some money – 5.8541 MWh times $11.38/MWh equals $66.62. The difference between the cost of increasing generation and the cost saved by reducing generation is $20.99 [$87.61 less $66.62]. However, this $20.99 only represents the cost of providing 0.0062 MW [5.8603 less 5.8541] to the SPP footprint. Therefore, to provide 1 more MW to the footprint, we would have to apply a factor of 1/0.0062 to the increase and decrease in generation. The total cost of this 1 MW is the SMP, and it will be $3,385/MWh [1/0.0062 times $20.99].

In the situation of a violated transmission constraint, the SMP will be driven high by (a) a *large* price difference between the two Resources used to provide the next MW and (b) a *small* difference between the shift factors of the two Resources.

Again, recall that the LIP equals the SMP plus an adder equal to the shift factor for a Resource times the Shadow Price for transmission congestion. Because the flowgate constraint is violated, we know the Shadow Price initially is set equal to the Penalty Factor of $20,000/MW.[9] When the Penalty Factor sets the Shadow Price, Price Administration occurs. Price Administration recalculates the Shadow Price and the reported Shadow Price was equal to negative $19,995.94/MWh. The shift factor for all SPS Resources is approximately negative 0.80 (negative because it is on the importing side of the constraint). The second component of the LIP for any given SPS Resource, therefore, was approximately $16,000/MWh. Combined with the SMP, the calculated LIP for any given SPS Resource was approximately $19,385/MWh, which is very close to the $20,000/MWh reported LIP from the deployment test (the calculations done here involve some estimation and rounding).

4. Impact of the Price Event

The effect on settlements of the $20,000/MWh LIP for the five-minute interval was isolated to Market Participants in the SPS area. Moreover, since LIPs are settled by the hour, it is important to see that the $20,000/MWh interval LIP was averaged in with the other eleven intervals for the hour ending at midnight. The average price for that hour for the SPS area was $1,695.57/MWh and that is the LIP used for settlement.

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[8] Note that approximations are used in the calculation and thus we are only approximating the SMP for this interval. The optimization of the linear equation will use exact information and thus will be slightly different.

[9] The Shadow Price is always negative in the equations because it represents the savings of relieving the constraint.

We are not able to determine the extent to which these prices affected all Market Participants because there were data submission errors for some of the load locations. According to SPP, the energy imbalance volume for some loads was not being submitted correctly by metering agents at that time. There do not appear to be any errors in the manner in which generation data was submitted and therefore, it is useful to examine the impact of these prices on generators.

One Market Participant benefited from the price event because it sold more generation than it used to serve its customers (its load): in this one hour it sold 441 MWh of generation. It, therefore, made approximately $750,000 [441 times $1,695.57] for the sale of its generation.

Another Market Participant had the opposite experience since it bought more electricity than it generated. It bought an additional 70 MWh to make up for imbalances in its generation. Buying a total of 70 MWh means that it paid a total of about $120,000 for generation.

5. The Price Event at Midnight

All of the detailed explanation above was for the interval ending at 11:55 p.m. because there was a data input error by SPP for the interval ending at midnight. The error was to input a negative flowgate capacity for the SPP to SPS flowgate. This meant an immediate violation of the constraint with the extreme LIP resulting. Under the SPP Tariff, input errors such as this would be corrected and the LIP recalculated for settlement. The recalculated LIP for this interval was approximately $41/MWh. As such, there would have been no significant impact on consumer bills.

This "input" error apparently aggravated a broader software (process) error concerning market flow calculations. SPP is now addressing this matter.

B. Diagnosis Number Two

Date of Test: September 13, 2006
Four Deployment Intervals: Ending 1:40 p.m. to ending 1:55 p.m.
LIPs of Interest: Approximately negative $1,600/MWh to $1,800/MWh across the intervals

1. Background on the Price Event

SPP conducted a deployment test for 4 hours from 10:00 a.m. to 2:00 p.m. on September 13, 2006 (CPT). With twelve five-minute deployment intervals in each hour, the test covered forty-eight deployment intervals in total. The price extremes diagnosed herein were seen in four intervals ending 1:40 p.m. through 1:55 p.m.[10] Prices ranged from a low of negative $1,600/MWh to a high of $1,800/MWh.

[10] The McPherson flowgate was constrained for the interval ending at 11:35 a.m. and did see extreme prices, but that event is not diagnosed here.

A simulated transmission constraint on the Flint Creek flowgate was the primary reason for the extreme prices. This flowgate is at the eastern side of SPP near the Arkansas border. Again, note that the congestion on this line was not an actual TLR event; that is, SPP artificially created this constraint by decreasing the limit of the flowgate by 8 MW from 273 to 265. Once the limit was set at 265, the flowgate constraint was violated by 10 MW, 4 MW, 2 MW, and 3 MW respectively in the four intervals ending at 1:40 p.m. through 1:55 p.m.[11]

During these intervals, prices varied widely across the SPP footprint. For example, during the interval ending at 1:40 p.m., two Resources had prices at roughly the negative $1,600/MWh level; these Resources belonged to AEP and Arkansas Electric Cooperative (AECC)). Another seven Resources had prices in the range of negative $100/MWh to negative $600/MWh. Forty other online Resources – these included Resources of most Market Participants including even those at the western border of SPP – had prices between $100/MWh and $400/MWh. One Resource had a price near $1,250/MWh. The high LIP of $1,800/MWh was for an AEP Resource that was offline.

It is important to note that this wide range of prices is not being driven by Market Participants' offers into the market. One Resource submitted an offer of $125/MWh (given its dispatch level) and the next highest offer was at $70/MWh.

2. Causes of the Price Events

It is clear that the immediate cause of these extreme prices was the artificially imposed transmission congestion on the Flint Creek flowgate. However, these price events should not be dismissed just because this was only a simulated event. This is an event that could actually happen in the market and it has important consequences. The limit on the Flint Creek flowgate was only decreased by 8 MW and, yet, a constraint violation resulted for four consecutive intervals causing price extremes.

The price extremes resulted because there was a lack of available options to resolve the simulated constraint during the test. Shift factors indicate how much of an impact a Resource has on a flowgate – a higher shift factor indicates a higher impact. During these intervals there was only one power plant that had a shift factor above 5% (or below negative 5%). This plant was Flint Creek and it is composed of two 264 MW Resources, one of which is owned by AEP and the other is owned by AECC. Both Resources have shift factors of 9.5625% which means that close to 10% of the power generated there flows over the Flint Creek flowgate. Both of these Resources were self-dispatched and operating near their maximum capacity. This meant that neither of these Resources was available to the EIS Market to be dispatched down to a lower level of generation; moving to a lower level of generation would have decreased the flow on the Flint Creek flowgate and, thereby, ended the constraint violation.

[11] It appears that there was a violation of the Flint Creek transmission constraint that occurred during the process of artificially lowering the limit and therefore will not be diagnosed here.

There were only six online Resources that had a negative shift factor for the Flint Creek flowgate, and therefore, could relieve congestion by increasing generation (providing counterflow) within the constrained area. And only one of those Resources had a shift factor greater than the negative 1% (absolute value). Two of the six online Resources with negative shift factors, including the one with the shift factor greater than negative 1% (absolute value), were self-dispatched and, thereby, not available for deployment in the EIS Market. For the remaining four Resources available for deployment by SPP, three were already dispatched to their maximum limit and, therefore, could not increase generation. Consequently, there was only one Resource available to provide counterflow for the Flint Creek flowgate. This Resource had a ramp rate of 2 MW/minute and given its shift factor of negative 0.612%, it could not provide much relief. Because of these limited options, the flowgate violation could not be resolved easily and, therefore, the violation persisted for four consecutive intervals.

3. LIP Calculation

It is useful to walk through an example of the calculation of a LIP in these intervals with the constraint violation. We will use the interval ending at 1:40 p.m. As in Diagnosis Number One, to calculate the System Marginal Price (SMP), SPP turns to two Resources with positive shift factors indicating they are outside the constrained area; generation from the Resource with a lower shift factor will be increased and generation from the Resource with the higher shift factor will be decreased. The lower shift factor is 0.011044 and thus 90.5469 MW will provide 1 MW of flow on the flowgate. The higher shift factor is 0.011393; meaning 87.7732 MW will impact the flowgate by 1 MW.

The offer price of the lower-shift-factor Resource is $54.44/MWh. If we generate 90.5469 MWh at that price, we will spend $4,929.37 increasing generation. The offer price of the higher-shift-factor Resource is $47.60/MWh. By turning this Resource down 87.7732 MWh, we will save $4,178.00. The difference between the cost of increasing generation and the cost saved by reducing generation is $751.37. However, that $751.37 represents the cost of providing 2.7737 MW [90.5469 less 87.7732] to the SPP footprint. The total cost of just 1 MW is the SMP, and it is $270.89 [$751.37 divided by 2.7737].

Recall that the LIP is equal to the SMP plus an adder equal to the Resource's shift factor times the Shadow Price for the transmission congestion. The flowgate is violated so the Shadow Price is initially set to the penalty factor of $20,000/MW. After price administration the reported Shadow Price was negative $19,380.05/MWh (always negative). The shift factor for the lowest cost Resource was 0.095625. Consequently, the LIP for this Resource was approximately negative $1,585/MWh. The shift factor for the highest cost online Resource was negative 0.048213. Consequently, the LIP was approximately $1,200/MWh. Both of these LIPs are very close to the actual LIPs that these Resources saw (all of the calculations done here involve some estimation and rounding).

4. Impact of the Price Events

The hourly prices actually paid in settlement are an average of the twelve interval prices so the impact of price extremes in a few intervals is muted to some extent. The single lowest average settlement LIP for the relevant hour was negative $631.37/MWh and, not surprisingly, applied to the Flint Creek Resources. The highest hourly settlement LIP was $757.93/MWh and it applied to AECC's load. In addition one Resource saw an hourly settlement LIP of $516.73/MWh. The actual impact of these settlement prices also may have been diminished by the fact that the relevant Market Participants were not participating in the market to any substantial degree.

We are not able to determine the extent to which these prices affected all Market Participants because there were data submission errors for some of the load locations. According to SPP, the energy imbalance volume for some loads was not being submitted correctly by metering agents at that time. There do not appear to be any errors in the manner in which generation data was submitted and therefore, it is useful to examine the impact of these prices on generators.

Only one Market Participant saw a significant impact on what it was paid as a generator. It was paid $350,663.17 for reducing the amount of generation it produced. Since its Resources made the constraint worse (this resulted in negative LIPs), the EIS market reduced the Market Participant's generation to decrease the congestion. Consequently, it was paid for the amount of generation it decreased. Again, we cannot identify the total impact on this participant because of a data error for load.

C. Diagnosis Number Three

Date of Test: October 12, 2006
One Deployment Interval: Ending 10:05 a.m.
LIPs of Interest: Approximately negative $1,900/MWh to $3,200/MWh

1. Background of the Price Event

SPP conducted a deployment test for fifteen hours from 5:00 a.m. to 8:00 p.m. (CPT) on October 12. Since there are twelve five-minute deployment intervals for each hour, there were a total of 180 intervals covered for this deployment. Price extremes were only seen in five intervals overall. The most extreme LIP prices were approximately negative $1,900/MWh and $3,200/MWh, and these prices occurred in the deployment interval ending at 10:05 a.m.

A transmission constraint for a temporary flowgate was the primary cause of the extreme prices. SPP created this constraint administratively for purposes of deployment in order to test its ability to create a flowgate on the fly (a temporary flowgate). It appears that SPP used elements between Oneta and Broken Arrow (east of Tulsa). The limit of the temporary flowgate was 232 MW and the actual flow for the interval ending 10:05 a.m. was 238 MW; thus, there was a violation of 6 MW. It should be noted that in the subsequent four intervals the flowgate limit was increased to 236 MW which was exactly equal to the power flow at that time. In other words, the flowgate was no longer violated.

During the interval ending at 10:05 a.m., two online Resources had LIPs slightly above $3,000/MWh while three online Resources had LIPs around $2,000/MWh. Eight more online Resources had a LIP in the range of $400/MWh to $1,000/MWh. Eight other online Resources had negative LIPs ranging from negative $100/MWh to negative $1,900/MWh. Again, it is important to note that offer prices submitted by Market Participants are not the cause of these extreme LIPs. The two highest offers were for $200/MWh and $125/MWh, respectively, but no other Resource submitted an offer higher than $75.25/MWh.

2. Causes of the Price Event

The immediate cause of the extreme prices was the violation of the temporary flowgate, which was again a planned market test event. There were thirteen online Resources that were on the importing side of the flowgate and, thus, were in a position to increase generation to relieve the violation (provide counterflow). Four of these Resources had a shift factor greater or equal to the absolute value of negative 9%. Consequently, these Resources were in the best position to provide counterflow; however, three were self-dispatched and the other Resource was already dispatched to its maximum level. Five additional online Resources had a shift factor between negative 2% and negative 7%, yet none of them were available for market dispatch either (one was self-dispatched, one was in manual mode, and three submitted zero dispatchable range). The four remaining online Resources on the importing side of the constraint all had shift factors between 0% and negative 2%. Two of these four were already at their maximum capacity and the other two were dispatched at their maximum ramp rates (5 and 2 MW/minute, respectively). Given their low shift factors on the constraint, however, these two Resources could not provide the necessary counterflow to avoid a violation.

It is also important to examine the Resources that could end the violation by decreasing generation on the exporting side of the constraint. There were seven such Resources that had a shift factor of 5% or greater. Five of these were dispatched down at their maximum ramp rates; however, this did not remove enough flow to avoid the violation. The other two Resources were self-dispatched and operating at close to their maximum capacity and may have been able to provide some relief had they been available to the market. Those Resources had shift factors of 6.5% and 11%, respectively.[12]

3. LIP Calculation

It is useful to examine the LIP calculation for the interval ending at 10:05 a.m. As in other cases diagnosed here, the System Marginal Price (SMP) reflects the swapping of generation by two Resources on the exporting side of the constraint; we will turn up the marginal unit with the lower shift factor and turn down the marginal unit with the higher shift factor. The lower shift factor is 0.013486 which means that 74.1510 MW must be generated to have a 1 MW impact on the constraint. The offer price of this Resource is

[12] Note that the Resource with a shift factor of 11% had a ramp rate of 15 MW/min. Had it been available, it could have been dispatched down 65 MW until it reached its operating minimum. Since it had an 11% shift factor on the constraint, this reduction would have removed 7.15 MW from the flowgate.

$45.53/MWh, so it costs approximately $3,376 to increase generation. The higher shift factor is 0.013529 and therefore 73.9153 MW are required to impact the constraint by 1 MW. The offer price of this Resource is $44.65/MWh; consequently, roughly $3,300 is saved by turning this Resource down. The total cost of providing 0.2357 MWh to the SPP footprint is $76. Therefore the SMP is approximately $322/MWh ($76 divided by 0.2357 MWh).

Remember that the LIP is calculated by adding the SMP to an adder consisting of the shift factor times the shadow price. Since there was a violation of the constraint, the shadow price is initially set to (negative) $20,000/MWh. After price administration occurred, the shadow price was negative $19,984/MWh. The LIP for the least expensive Resource is approximately negative $1,880/MWh ($320/MWh plus 0.11 times negative $19,984/MWh). The LIP for the most expensive Resource is approximately $3,200/MWh ($320/MWh plus a negative 0.145 times negative $19,984/MWh). Both of these calculated LIPs are very close to the extreme prices reported by SPP (the calculation done here involves some estimation and rounding).

4. Impact of Price Events

SPP has not yet issued settlements for this trial. Therefore we can not yet determine the impact of these extreme prices; however, it should be noted that price extremes only occurred in five five-minute intervals and are likely to be dampened by the LIPs in the other intervals for the hour.

IV. ADDITIONAL BACKGROUND AND DISCUSSION

A. How other ISOs/RTOs address transmission constraint violations

Generally, all ISOs/RTOs use a linear program to dispatch Resources to find the lowest cost optimal solution while taking into account economic and physical constraints of the system. As already discussed, there will be times when the real-time dispatch algorithm cannot find a solution because there are no available Resources to be dispatched to meet the system energy needs while maintaining the integrity of each operating and transmission constraints (e.g., all Resources on the inside of the constraint are limited based upon their ramp rates). Therefore, each ISO/RTO needs to have a policy for relaxing one of the constraints in order to meet demand. SPP's policy is to use penalty factors which are also used in ERCOT and ISO-NE. New York and PJM both have a procedural operating policy for waiving the constraints.

While the issue is well understood and well publicized, details on the precise approach used are hard to document. The following limited discussion is based on documents from and telephone calls with other ISOs/RTOs.

1. ERCOT

In 2005, ERCOT revised the penalty factors used to solve its dispatch algorithm when there was a constraint and no available Resources to solve the constraint. As shown below in Table Two, ERCOT originally had shadow price caps at a significantly higher level and then they revised downward.

TABLE TWO
ERCOT SHADOW PRICE
CAPS (PENALTY FACTORS)

Category	Old Penalty Factor	Revised Penalty Factor
Ramp Rate Constraint	$75,000	$1,001[13]
OC3 (Contingency)	$250,000	$3,000
Local Constraint (OC2)	$500,000	$3,000
Zonal Congestion Constraint (OC1-CSC)	$750,000	$2,500
Local Constraint (OC3-Basecase)	$1,000,000	$100,000

According to the May 25, 2005 Market Notice:

> "limiting the Zonal Congestion (OC1) Constraint will limit CSC Shadow Prices to $2,500/MWh. This Penalty Factor for Zonal Congestion defines the limit at

[13] According to the September 15, 2006 Market Notice of System Change, the Ramp Rate Constraint penalty factor will be raised to $1,400/MW. However, it is unclear when the change to the penalty factor will be in place.

which the MCE will stop attempting to solve Zonal Congestion. Analysis and discussions with Market Participants have indicated that the $2,500/MWh limit should be large enough to ensure that the MCE will use all available Balancing Energy from the zones with significant effect on Zonal Congestion. The effect on the Balancing Energy Services market in the ERCOT Region will be that the system will stop trying to solve Zonal Congestion once the marginal cost of doing so exceeds the Zonal Congestion Penalty Factor. When the cost of solving Zonal Congestion has reached this limit, ERCOT will use operator manual dispatch procedures to ensure system security."[14]

2. ISO-NE

ISO-NE also uses penalty factors in calculating its real-time marginal prices. According to an ISO-NE memorandum:

> "there are penalty costs within the algorithm for violating any unit characteristics in the offer data (i.e., Resource ramp rates and operating limits), penalty costs for violating transmission operating parameters (i.e., line and/or interface limits), and penalty costs for violating the system power balance equations at a nodal level and for the Control Area. With the addition of the reserve constraints into the objective function, reserve constraint violation penalty costs (factors) must be developed and implemented in order to maintain the integrity of the dispatch solution."[15]

For the real-time markets, ISO-NE calculates locational marginal prices for energy and reserve clearing prices by jointly optimizing the economic dispatch of energy and operating reserves using the energy offers and Reserve Constraint Penalty Factors.[16] The resulting LMPs is the cost of meeting both energy, reserves and the operating constraints discussed above. We are currently looking into the level of the penalty costs for violating the operating constraints discussed above; however, we do have the Reserve Constraint Penalty Factors which are capped at a total of $1,000/MW.[17]

3. NYISO

NYISO uses a policy procedure for solving the dispatch solution when no Resources are available. Specifically, NYISO's Transmission and Dispatching Operations Manual states: "if any transmission constraints are unsolved, SCD resets the limits of the violated constraints equal to the power flows of those constraints at the end of the feasibility step (forcing the problem to be 'feasible')".[18] As part of the procedure the NYISO shift supervisor will receive an alarm message when the SCD program is not

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[14] *See* Market Notice of System Change dated May 25, 2005.

[15] *See* Rationale and Derivation of proposed Real Time Reserve Constraint Penalty Factors, Dated April 29, 2005. at p. 1-2

[16] *See* Market Rule 1, Section III. 2, Calculation of Location Marginal Prices. Available at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1.pdf at Original Sheet No. 7123A

[17] Each component of reserves has its own Penalty Factor: Ten-Minute Spinning is $50/MWh, Ten-Minute Non-Spinning is $850/MWh and Ten-Minute operating is $100/MWh.

[18] *See* Transmission and Dispatching Operations Manual at p. 12

able to solve all the constraints. According to the manual, NYISO can then take alternative action to bring the constraints under control.[19]

4. PJM

When asked if PJM uses penalty factors when there is no solution to the linear optimization function, PJM responded that since LMP is based on actual operating conditions, when there is no solution to the security-constrained economic dispatch, it will use the last set of dispatch instructions from a previous dispatch interval.

B. LIP Volatility Other than that reflected in the price extremes

Market Participants asked us to address the volatility of LIPs other than that reflected in the price extremes. Our approach was to exclude the deployment intervals with the price extremes, and to focus on the many remaining deployment intervals during the SPP tests. We then compared the volatility of SPP's LIPs to the volatility of locational prices in the New York ISO Market; NYISO also has a five-minute dispatch interval, the interval data is made public, and pricing is nodal.

1. Choosing a Measure of Volatility

The most common statistic in measuring price volatility is the standard deviation. Standard deviation, roughly stated, is the average variation or divergence from the average (or mean) price in a market. In general, a higher standard deviation indicates that there is a greater difference from one price period to the next. That is, a higher standard deviation indicates greater price volatility.

However, without comparing it to the average price in each market, the standard deviation does not tell very much. A standard deviation of $10 would be much more significant in a market where the average price was $20, than in a market where the average price was $100. Therefore, as an additional indicator of volatility, we calculated standard deviation as a percentage of the average price. This is known as the Coefficient of Variation (COV) in the literature. Similar to standard deviation, a higher COV indicates greater volatility.

2. Price Volatility in SPP's Deployment Tests

We should note that it was difficult to accurately compare the price volatility in SPP to other markets because the LIP data is most likely not comparable as a result of (a) having only limited intervals to analyze and (b) having a voluntary market. That being said, the following tables give an initial indication of the level of volatility in SPP. We believe that it would be beneficial to review the volatility further once the market is running.

Table Three, below, shows the month, day, number of hours of the market trial, the simple average of the LIPs for trial, the standard deviation of the LIPs for the trial, the

[19] *Id.*, at p. 14

coefficient of variation and minimum and maximum LIPs in any five-minute interval. Again, this data excludes intervals with extreme prices.

TABLE THREE
ASSESSMENT OF SPP
VOLATILITY EXCLUDING
INTERVALS WITH EXTREME PRICES[20]

Month	Day	# of Trial Hours*	Average SPP LIP ($/MWh)	Standard Deviation of LIPs ($/MWh)	Coefficient of Variation	Minimum Five Minute LIP ($/MWh)	Maximum Five Minute LIP ($/MWh)
9	6	4	$ 52.28	$ 8.91	17%	$ -	$ 61.93
9	12	5	$ 26.15	$ 15.35	59%	$ 8.64	$ 66.96
9	13	5	$ 40.72	$ 20.43	50%	$ (485.97)	$ 626.26
9	18	5	$ 34.44	$ 7.69	22%	$ 15.90	$ 53.80
9	20	9	$ 34.76	$ 15.20	44%	$ (20.19)	$ 332.20
9	27	9	$ 19.64	$ 13.86	71%	$ -	$ 65.16
10	11	5	$ 43.51	$ 2.22	5%	$ (6.27)	$ 121.14
10	12	16	$ 44.50	$ 13.84	31%	$ (171.32)	$ 418.79

3. Price Volatility in the New York ISO

Using Table Three as a measure of SPP volatility, we needed to compare the results to another market. As noted, we looked at the NYISO Real-Time Market because five-minute data was available for this nodal market. For each day, we took the simple average of the NYISO Locational Based Marginal Price (LBMP), the standard deviation, and the coefficient of variation of the five-minute LBMP for all reported nodes. We then aggregated and summarized our findings in Table Four below. For example, in the 30 days in September, the simple average of the daily NYISO LBMP was $47.39/MWh and the average of the daily standard deviation was $26.49. The average daily coefficient of variation was 59.4%. The maximum coefficient of variation seen in any one day in September was 160% and the minimum was 21%.[21]

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[20] Intervals excluded include: '06SEP2006:19:15:00', '06SEP2006:19:20:00','06SEP2006:19:25:00', '06SEP2006:19:30:00', '12SEP2006:05:40:00', '13SEP2006:16:35:00', '13SEP2006:18:30:00', '13SEP2006:18:40:00', '13SEP2006:18:45:00', '13SEP2006:18:50:00', '13SEP2006:18:55:00', '20SEP2006:15:45:00', '20SEP2006:17:00:00', '20SEP2006:17:05:00', '20SEP2006:17:10:00', '27SEP2006:04:55:00', '27SEP2006:05:00:00', '12OCT2006:15:05:00', '12OCT2006:20:55:00', '12OCT2006:21:10:00', '12OCT2006:21:15:00', '12OCT2006:21:25:00'

[21] We felt it would be beneficial to give an indication of the volatility for another market in addition to NYISO. Therefore we examined ERCOT. While not directly comparable, as the data for ERCOT is zonal and is for fifteen-minute intervals, we found the average daily coefficient of variation ranged from 44.9% to a high of 86.9% for the first eight months of 2006.

TABLE FOUR
ASSESSMENT OF NYISO
REAL-TIME VOLATILITY[22]

Month	Average NYISO LBMP ($/MWh)	Average Daily LBMP Standard Deviation ($/MWh)	Average Daily Coefficient of Variation	Maximum Coefficient of Variation	Minimum Coefficient of Variation
8	$ 89.36	$ 65.21	61.4%	121%	28%
9	$ 47.39	$ 26.49	59.4%	160%	21%
10	$ 47.56	$ 24.95	50.2%	95%	26%

4. Preliminary Conclusion

Based upon this assessment, it appears that the LIP volatility in SPP trials (excluding price extremes) is not out of line with the volatility experienced in the NYISO real-time market. We say this based on a comparison of coefficients of variation. Across separate abbreviated days of trials, the daily coefficient of variation averaged 37% (this is a simple average of those shown in Table Three). For the NYISO, the average of the daily coefficient of variation ranges from 61.4% in August to 50.2% in the first half of October. Again, we do caution that there is only limited data for SPP and an on-going assessment of volatility should be included as the market goes live.

[22] Please note only partial data was available for October.

V. CONCLUSIONS AND RECOMMENDATIONS

It is important to keep in mind that these price extremes are occurring during trials. It is fair to say that, just like any rehearsal, trials are a time to find mistakes and correct them. Indeed, it is expected that mistakes will continue to be made and corrected. Also, for Market Participants, trials are a time to try things out without any financial consequence – in short, we expect Market Participants to do things in trials that they will not do when the market is live.

Further, price volatility does not always indicate a defect in an electricity spot market. More specifically, price extremes do not necessarily reflect a flaw in market design. No matter how extreme, if spot prices are accurately signaling market conditions, then they are doing their job. In particular, locational prices like LIPs are meant to reveal transmission constraints, which in turn signal the need for new investment. In this sense, the extreme LIPs seen in the deployment test are accurately reflecting market conditions and signaling the need for investment in the long run.

LIPs can give the signal for the right response in the short run, too. For example, an extreme negative LIP for a Resource, like the one that occurred on September 13th, indicates that the negative-LIP Resource is making the constraint worse. Therefore, the Resource should have to pay to increase its generation. However, the Resource can make money in the EIS market in this situation by turning down its generation. If a Resource produces less than it schedules, it has a negative imbalance. The negative imbalance multiplied by the negative LIP results in the Resource being paid. The market is sending the right signal in this instance because it is paying a Resource to decrease its generation in order to remove flow that is causing the constraint.

The same rationale applies for an extreme positive LIP, like those seen during the deployment on September 27th. A very high positive LIP indicates that the high-LIP Resource is in a valuable position to provide relief to the constraint. If it generates more than it scheduled, it will get paid the difference between actual generation minus scheduled generation multiplied by the high positive LIP. Once again, the market is sending the right signal, because it is paying a Resource to increase its generation in order to provide relief to the constraint.

However, we believe that the LIPs are doing their job with unnecessary exuberance. We recommend the following three actions to mitigate (not eliminate) price extremes: (a) decrease Penalty Factors, (b) give SPP flexibility to alter effective limits on flowgates, and (c) encourage participation by Market Participants for the good of the market.

A. Decrease the Penalty Factors

As illustrated in our diagnoses above, penalty factors are a major determinant in setting the shadow price (and therefore the LIP) when a flowgate is violated. To illustrate the impact further, we asked SPP to run some model simulations in its stand alone dispatch engine (Scheduling Pricing Dispatch (SPD)) for the deployment interval ending at 11:55 p.m. on September 26th. During each model run, SPP altered only the penalty factor. SPP ran the simulation three times with the following three different penalty factors: (a) $1,000/MW, (b) $10,000/MW, and (c) $30,000/MW. Remember that the actual deployment had a Penalty Factor of $20,000/MW. The results of the simulation are summarized in the table below.[23]

TABLE FIVE
CALCULATIONS WITH VARYING PENALTY FACTORS

Penalty Factor	$ 1,000	$ 10,000	$ 20,000	$ 30,000
Shadow Price	$ 916.00	$ 9,927.00	$ 19,995.94	$ 29,999.00
Minimum LIP	$ 10.16	$ (28.48)	$ (76.04)	$ (115.99)
Maximum LIP	$ 929.48	$ 9,939.34	$ 20,005.44	$ 30,005.34

The table documents that the Penalty Factor determines the Shadow Price and, thereby, determines the Maximum LIP.[24] See that the Shadow Price and the Maximum LIP are almost identical to the Penalty Factor in each of the above cases. The level at which the Penalty Factor is set is a matter of judgment and, therefore, we would recommend lowering the penalty factor. However, the danger in decreasing the penalty factor is that there may be more violations and violations of larger magnitudes. Therefore, we believe a lower penalty factor should be used to start the market, but that its impact be studied over the first three- and six-month periods.

B. Allow Flexibility on Effective Limits for Flowgates

Our diagnoses also shows that a relatively small violation of the effective limit for a flowgate (10 MW or fewer) is causing the price extremes. It is important to note that these flowgates are not being violated beyond their actual limit, but rather their effective limit. Generally speaking, a flowgate's effective limit is equal to its actual limit less some portion of capacity reserved for emergency situations, otherwise known as Transmission Reserve Margin (TRM) in SPP. SPP calculates TRM in order to account for generation outages.[25] If a generator goes offline and a reserve sharing event occurs, each flowgate has a margin of capacity that is guaranteed to be available in order to transfer the reserve power. So when the effective limit is violated in the above diagnoses, the violation is moving into the TRM.

SPP operators should have the flexibility to re-set effective limits on flowgates to avoid having very small constraint violations that cause extreme LIPs. Giving operators this flexibility does involve some discretion to reduce temporarily the TRM. However, it should be noted that currently, non-firm transmission service is sold into TRM. This is done to maximize the use of the transmission system and does not harm reliability because, if there is an emergency, these non-firm schedules sold into the TRM will be

[23] All prices in the table are in $/MWh and the shadow price is always negative.
[24] All prices shown here are after price administration.
[25] Transmission Owners can request additional TRM from the Transmission Working Group, who has the discretion to accept or reject the requests. *See* Southwest Power Pool Criteria July 25, 2006 Revision ("SPP Criteria") at Section 4.3 and SPP Open Access Transmission Tariff at Attachment C.

curtailed.[26] Therefore, in essence, SPP already has the discretion to use TRM for transmission service. This discretion or flexibility should be extended to EIS dispatch in order to avoid extreme LIPs resulting from a small violation of the TRM.

The effect of increasing an effective limit on extreme prices can be seen in the deployment test on October 12th. During this deployment, the Oneta-Broken Arrow flowgate had an effective limit of 232 MW. Note that the actual emergency limit is 265 MW. For the interval ending at 10:05 a.m. the actual flow was 238 MW, and therefore, the flowgate was violated by 6 MW. For the following four intervals the limit was increased to 236 MW and the flow was 236 MW. Consequently there was no violation and no extreme LIPs in the subsequent four intervals. It is not clear whether or not SPP was using its discretion to raise the effective limit, or if this was part of their testing procedure of the constraint, but regardless, the slight modification in effective limit had a profound impact.

C. Encourage Market Participant Participation for the Good of the Market

Market Participants should be committed to making a *voluntary* EIS Market work to the benefit of consumers. Price extremes can stand in the way of achieving that goal even if their actual impact on customer bills is muted. The commitment to a successful voluntary market should include Market Participants scheduling and offering (rather than self-dispatching) key Resources to the Market and also assuring reasonable ramp rates for those Resources.

We asked SPP to complete some model runs in SPD to illustrate the effect of minor changes to the availability of key Resources on the extreme LIPs. The first model run is for the deployment interval ending at 11:55 p.m. on September 26th. For that model run, everything was left identical to the actual dispatch, except the ramp rate for one SPS Resource was increased by 1.5 MW/min. The result was no violation of the SPP to SPS ties at all. The SMP decreased from approximately $3,385/MWh to approximately $19/MWh. The new shadow price was negative $31.60/MWh (down from nearly negative $20,000/MWh). Finally, LIPs ranged anywhere from $13.63/MWh to $45.78/MWh (as opposed to negative $76.04/MWh to $20,005.44/MWh).

The second model run that SPP did for us was for the interval ending at 1:40 p.m. on September 13th. During this run, SPP left everything the same as the actual test, except it made the two Flint Creek Resources available to be dispatched by SPP rather than having them be self-dispatched. Making these Resources available to the market did not solve the flowgate violation for the interval ending at 1:40 p.m. However, had the Resources been available, the flowgate violation would have occurred only for one interval as opposed to the four consecutive intervals that it was actually violated. It is important to note that the Flint Creek Resources were the only ones that had this high of an impact on the constraint; that is, other self-dispatched Resources would not have been in a position to provide the necessary relief to decrease the amount of violations.

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[26] *See* SPP Criteria at Section 4.3.3.

These two simulations illustrate the importance of Market Participants being fully committed to the success of the EIS market.