UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp,		
Complainant,	)	
	)	
v.	)	
	)	
Reliant Energy Services, Inc.	)	Docket No. EL02-80-000
Morgan Stanley Capital Group Inc.	)	EL02-81-000
Williams Energy Marketing & Trading Co.	)	EL02-82-000
El Paso Merchant Energy, L.P.,	)	EL02-83-000
	)	
Respondents.	)	(consolidated)

PREPARED REBUTTAL TESTIMONY OF
DR. TIMOTHY D. MOUNT
ON BEHALF OF PACIFICORP

Q. ARE YOU THE SAME DR. TIMOTHY MOUNT WHO HAS PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am. My Direct Testimony in this proceeding is set forth in Exhibit PAC-14.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to answer specific criticisms of my Direct Testimony raised in testimony sponsored by FERC staff and the Respondents. In particular, I will show why market fundamentals do not provide a complete explanation of the unprecedented high forward prices for electricity in the western markets during the period when the spot markets were dysfunctional (i.e., June 2000 to June 2001). In addition, I have improved upon the analysis of the relationship between spot prices and forward prices of electricity that I provided in my Direct Testimony at Exhibit PAC –14. The new analysis is based on the data for forward prices at Palo Verde that were used by PacifiCorp when the contested forward contacts were signed.

Q. WHY DO YOU CONSIDER THIS NEW DATA IMPORTANT?

A. My original analysis of forward prices was based on data from the New York Mercantile Exchange ("NYMEX"). During the period when the western spot markets were dysfunctional, there was very little trading of electricity for western markets at NYMEX. Therefore, the quality of the price data for electricity was not of the same caliber as the typical quality that one expects to have in an active NYMEX market for natural gas such as Henry Hub. The importance of the

PacifiCorp data is that these forward prices were used to make decisions about contracts.

Q. ARE THERE ADDITIONAL ISSUES THAT YOU PLAN TO ADDRESS?

A. Yes. I will provide additional clarification of

- Why I used prices of natural gas at Henry Hub rather than prices for delivery in California.
- Why I did not use the reported spot prices from the California Independent System Operator ("CAISO").
- Why my model of forward prices incorporates the effects of market fundamentals as well as the effects of the dysfunctional spot market.

Q. PLEASE EXPLAIN WHY YOU USED PRICES OF NATURAL GAS AT HENRY HUB.

A. Last summer FERC Staff released a report titled "Initial Report on Company-Specific Separate Proceedings and Generic Revelations; Published Natural Gas Price Data; and Enron Trading Strategies. Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices." (Docket No. PA02-000, FERC, Washington D.C., August 2002)("FERC Staff Report") A major conclusion of the FERC Staff Report was that spot prices of natural gas had been manipulated and therefore, their unreliability renders "the prices in California delivery points inappropriate for setting rates [for calculating refunds]." *(op. cit.* p. 73) In this Report, FERC Staff recommended that "refunds be computed based on the spot prices for natural gas reported at producing area pricing points, plus an allowance for transportation to California." *(op. cit.* pp. 4-5)

Q. HOW DO THE PRICES OF NATURAL GAS IN THE PRODUCING AREAS RELATE TO THE PRICE AT HENRY HUB?

A. The prices are very closely related. This relationship is demonstrated in Figure 1 of this Rebuttal Testimony. In addition, the FERC Staff Report *(op. cit.,* p. 74) shows that the correlation coefficients between the spot price at Henry Hub and the corresponding prices at four western production locations (San Juan Basin, Permian Basin, West Coast Basin, and NOVA Basin) are .968, .997, .979 and .985 respectively (a perfect positive correlation is 1 and no correlation is 0). In other words, there has to be a sound economic reason for departures from established price differentials between the price at Henry Hub and other locations. The NYMEX prices for Henry Hub provide a valuable source of reliable data in a national market for natural gas.

FIGURE 1: Spot Prices for Natural Gas at Henry Hub and Three Producing Areas (Source, Figure 8 in FERC Staff Report, *op. cit.* p. 72)

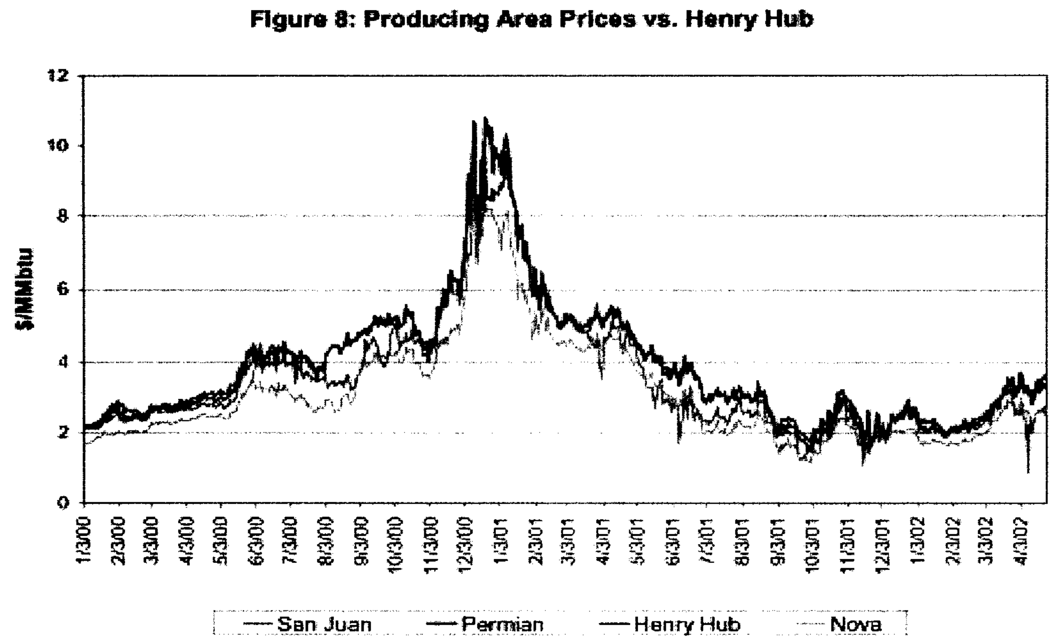
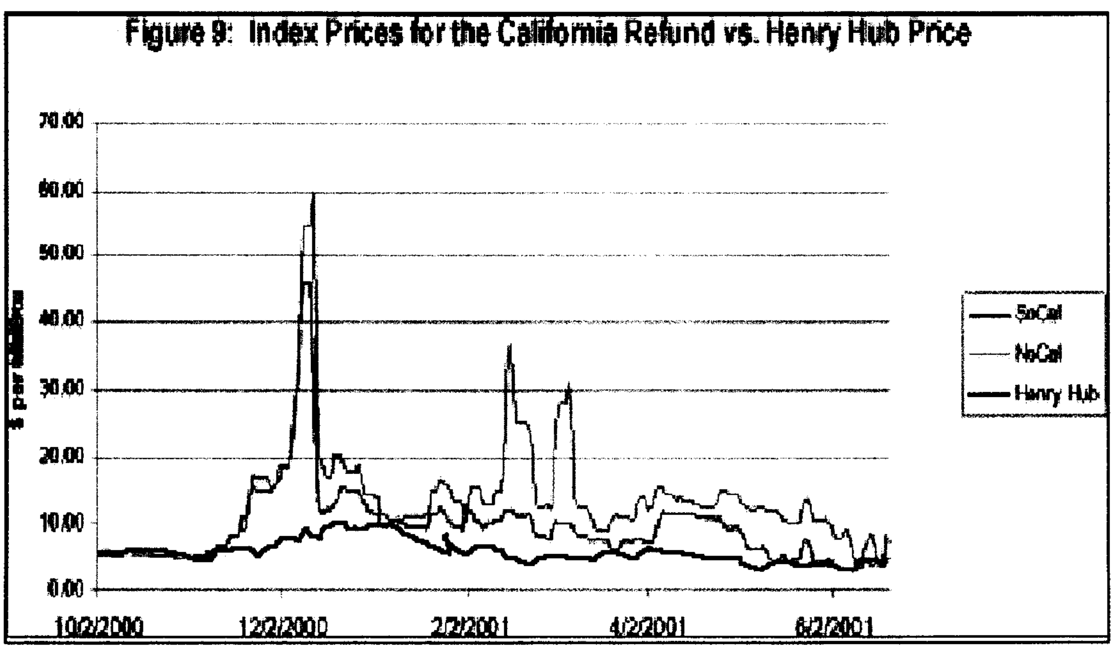


FIGURE 2: Spot Prices for Natural Gas at Henry Hub and Delivery Points in Northern and Southern California (Source, Figure 9 in FERC Staff Report, *op. cit.* p. 74)



Q. HOW DID THE PRICES OF NATURAL GAS BEHAVE IN CALIFORNIA?

A. Figure 2 shows that the reported spot prices for the delivery of natural gas in California increased dramatically in December 2000 in comparison to the corresponding increase at Henry Hub. Prices above $50/MMbtu were reported for Northern California compared to $10/MMbtu for Henry Hub (typical prices are below $5MMbtu, and the high prices at Henry Hub in December 2000 only persisted for a couple of months and then returned to normal levels by the Summer 2001. *See* FERC *op. cit.* pp. 71-72)

Q. IS THERE AN EXPLANATION OF WHY THE PRICES FOR NATURAL GAS IN CALIFORNIA WERE HIGH COMPARED TO THE PRICES AT OTHER LOCATIONS?

A. There is no simple answer, but the FERC Staff Report does give an extended explanation of how prices for natural gas could be manipulated by Enron-on-Line ("EOL"). *(op. cit.* pp. 51-60) The main findings are that (1) EOL was a primary source of price discovery for firms reporting prices for natural gas, and (2) "wash" trading between Enron and a counter party (a series of offsetting buy and sell transactions) can distort the reported prices. Indeed, a specific example in the Report shows how a large number of wash trades during the last half hour of trading on January 31, 2001 increased the price by $3MMbtu or about 25%). The overall conclusion is as follows:

The particular reporting methods used by any reporting firm are almost irrelevant, as long as its data sources themselves were biased due to substantial reliance on EOL. Having control over EOL gave Enron an easy means by which to influence the bids and offers posted on EOL, and the prices charged for transactions. In addition, the empirical evidence based on the data from EOL databases suggests that EOL was indeed a significant part of the price formation process, and that Enron took large positions in the markets using EOL. This gave Enron significant ability and incentive to manipulate the price data published by the reporting firms. Furthermore, internal memos indicate that Enron understood its ability to affect the published price data and the financial incentives it had to drive up the reported index prices. (op. cit. pp. 58-59)

Q. HOW DID YOU MEASURE THE PRICE OF NATURAL GAS IN YOUR ANALYSIS?

A. I used the spot and forward prices at Henry Hub because, in my opinion, NYMEX provides the most reliable source of data. These data are produced under strict rules of conduct that do not allow, for example, wash trades to distort prices. In addition, NYMEX, unlike EOL, is not permitted to make trades (i.e., take positions) in the market.

Q. HOW DOES THAT CHOICE AFFECT YOUR ANALYSIS?

A. I will follow the same approach proposed by FERC Staff to calculate refunds in California. Since the price of natural gas delivered in California is consistently higher than the price at Henry Hub, a markup is needed. However, the implicit conclusion of the FERC Staff Report is that the true markup during the period when the spot market for electricity was dysfunctional is not known because the reported delivery prices in California were manipulated. In my analysis, the ratio of the price of electricity to the price of natural gas at Henry Hub is used. The ratio accounts for the transportation allowance for natural gas, as well as other factors such as the heat rate and the cost of emission allowances for the marginal generator.

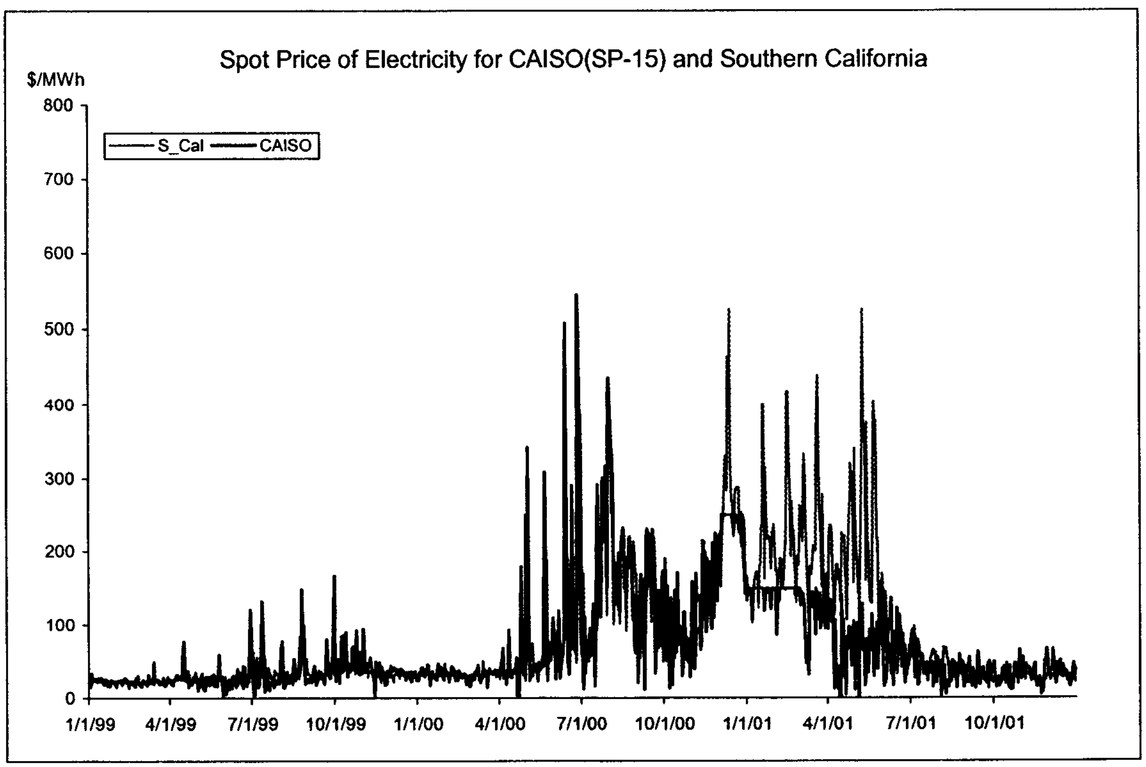
Q. ARE THERE ANY OTHER IMPLICATION OF USING THE PRICE OF NATURAL GAS AT HENRY HUB IN YOUR ANALYSIS?

A. Yes. I am treating the price of natural gas at Henry Hub (plus a transportation allowance) as a market fundamental for electricity. The price of natural gas is the most important determinant of the spot price of electricity in California because gas turbines are typically the marginal (most expensive) generators used to meet load. The evidence in the FERC Staff Report showing that the prices of natural gas delivered in California have been manipulated implies that these reported prices should not be treated as market fundamentals. This is a problem of measurement and not a problem of logic. The price of natural gas in California is a market fundamental, but unfortunately we do not know what the correct prices were when the market was dysfunctional. I believe that using the prices at Henry Hub (in a ratio with the price of electricity) is a better measure of market fundamentals than using the reported prices for delivery in California. This is exactly the same conclusion reached by the FERC Staff for calculating refunds in California.

Q. TURNING TO THE SECOND ISSUE, CAN YOU EXPLAIN WHY YOU DID NOT USE CAISO SPOT PRICES?

A. The CAISO market is a central market that ultimately controls the actual levels of generation for meeting the load for most customers in California. For this reason, it would be desirable to include the CAISO spot prices in the analysis. The reason for not doing so is because the reported CAISO prices are truncated. This can be clearly seen in Figure 3 for winter 2001. The reported spot prices are $150/MWh for most days even though many purchases were made at higher prices. Once again, this is a problem of measurement and not a problem of logic. The spot prices in southern California in Figure 3 are a better measure of actual market conditions.

FIGURE 3: Reported Spot Prices of Electricity at CAISO and Southern California Source, CAISO and Energy Market Report)



Q. WHY WERE THE REPORTED CAISO PRICES TRUNCATED?

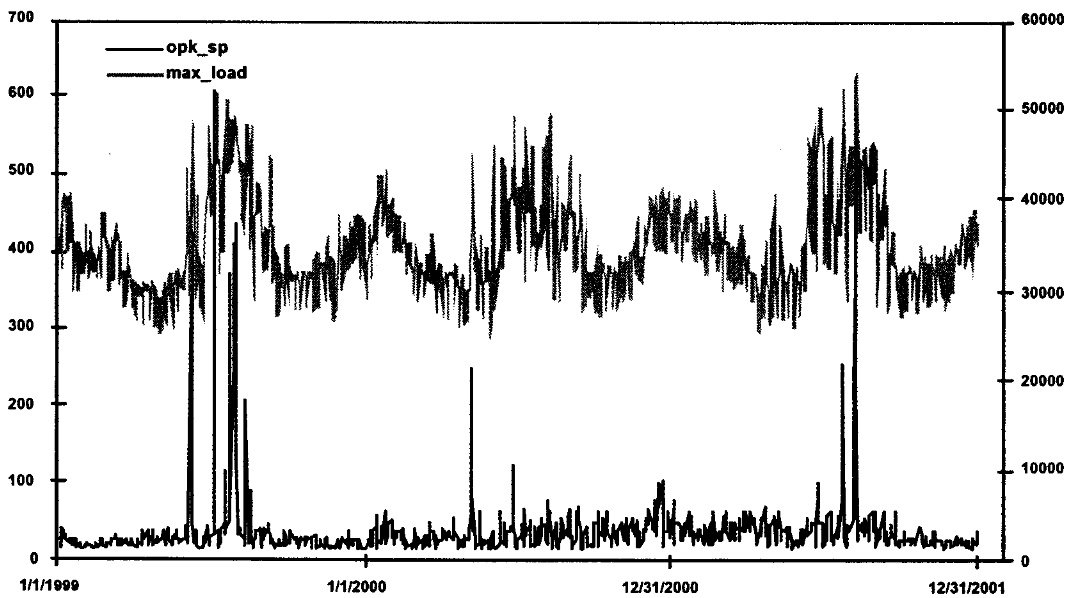
A. In December 2000, FERC ordered that a new "soft cap" auction should be implemented to replace the existing market operated by the ISO. This new form of market combined a uniform price auction with a discriminatory price auction. Offers to sell below the soft-cap ($150/WMh starting in January 2001) were used to set a market-clearing price in a conventional form of uniform price auction. However, any offers to sell above the soft-cap that were needed to meet the load did not set the market price and were paid the actual offer. The objective of this auction was to stop high offers *(i.e.,* above the soft-cap) from setting the market price for all capacity sold. The price data reported by the California ISO does not contain information about sales above the soft-cap, and the reported spot prices for the four locations used in my analysis (Mid-Columbia ["Mid-Col"], California Oregon Border ["COB"], Palo Verde ["PV"] and Southern California ["Scal"]) show that prices were persistently higher than the soft-cap from January to May 2001.

Q. WAS THIS TYPE OF PRICE BEHAVIOR UNUSUAL?

A. Yes. Spot markets in the east like the PJM market in Pennsylvania have a few infrequent price spikes during the summer months when the load on the system is relatively high, and this behavior is typical for a uniform price auction (*see* Figure 4). The persistence of high prices day after day in the soft-cap markets on the west coast was very unusual. This change in price behavior using the soft-cap auction is the main reason I allowed for structural shifts as well as seasonal effects in the econometric analysis of spot prices. The soft-cap auction was replaced in

June 2001, and at the same time, a "hard" price cap of $93/MWh was imposed by FERC on the Western Interconnection. The behavior of spot prices in California, particularly during the winter 2001, is truly extraordinary. Spot-prices are typically lower in the winter than the summer, but Figure 5 shows that this was definitely not the case in winter 2001.

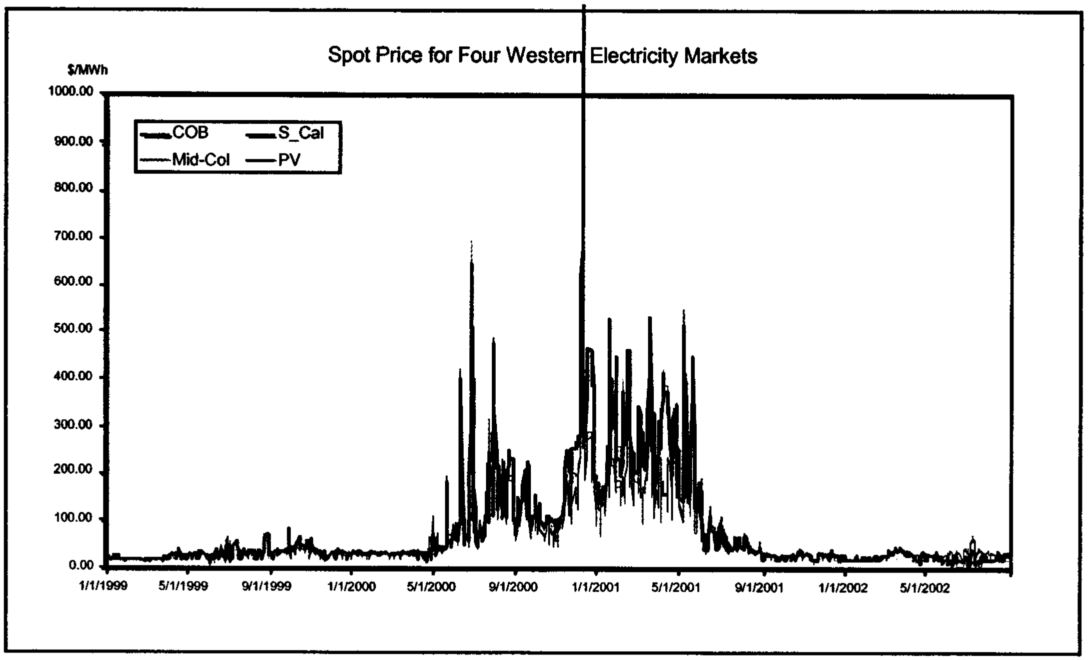
FIGURE 4: Spot Price of Electricity and the Maximum Daily Load in PJM (1/1/99 – 12/31/01) (Source, PJMISO)



Price $/MWh

Load MW

FIGURE 5: Spot Prices of Electricity in Four Western Spot Markets (1/1/99 – 8/30/02) (Source, Energy Market Report)



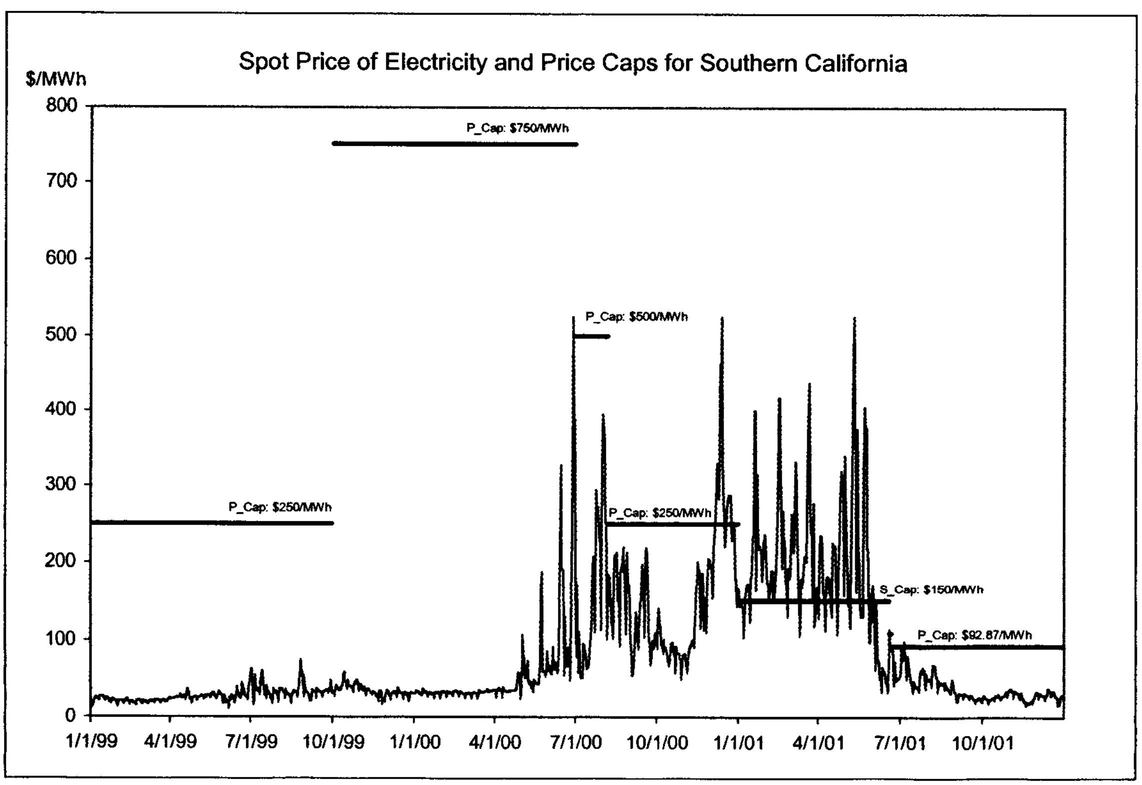
Q. DO YOU THINK THAT THE UNUSUALLY HIGH PRICES IN THE WINTER 2001 WERE CAUSED BY MARKET FUNDAMENTALS?

A. Not entirely. Spot prices of natural gas at Henry Hub and the producing areas were much higher than normal (see Figure 2). However, these spot prices were not nearly high enough to account for the high spot prices of electricity in the western markets. Other factors, such as replacing the hard price cap of $250/MWh with a soft price cap of $150/MWh, were also responsible.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY A HARD PRICE CAP?

A. Yes. Figure 6 shows the spot prices of electricity in southern California (the same prices are shown in Figures 3 and 5) and the price caps that were in effect. From January 1, 1999 to December 8, 2000, hard price caps (highlighted in blue) were enforced in the CAISO spot market, but they only affected the Californian market. When high spot prices occurred in summer 2000, the price cap was lowered from $750/MWh to $250/MWh. The implication of a hard price cap is that offers to sell in the market must be less than the price cap. When prices are restricted in this way, it is possible that the total generating capacity offered into the market is insufficient to meet the load. When this occurred in the Californian market, "Out-Of-Market" ("OOM") purchases were made by the CAISO, and these purchases could be paid prices above the cap. There is no reason to expect that a price cap imposed by the CAISO in California will be effective in other regions of the Western Inter-Connection. Up to December 7, 2000, the hard price caps imposed by CAISO only applied to California. The important change on June 19, 2001 with FERC's Mitigation Order was that a hard price cap of $92/MWh was imposed by FERC over the whole Western Inter-Connection.

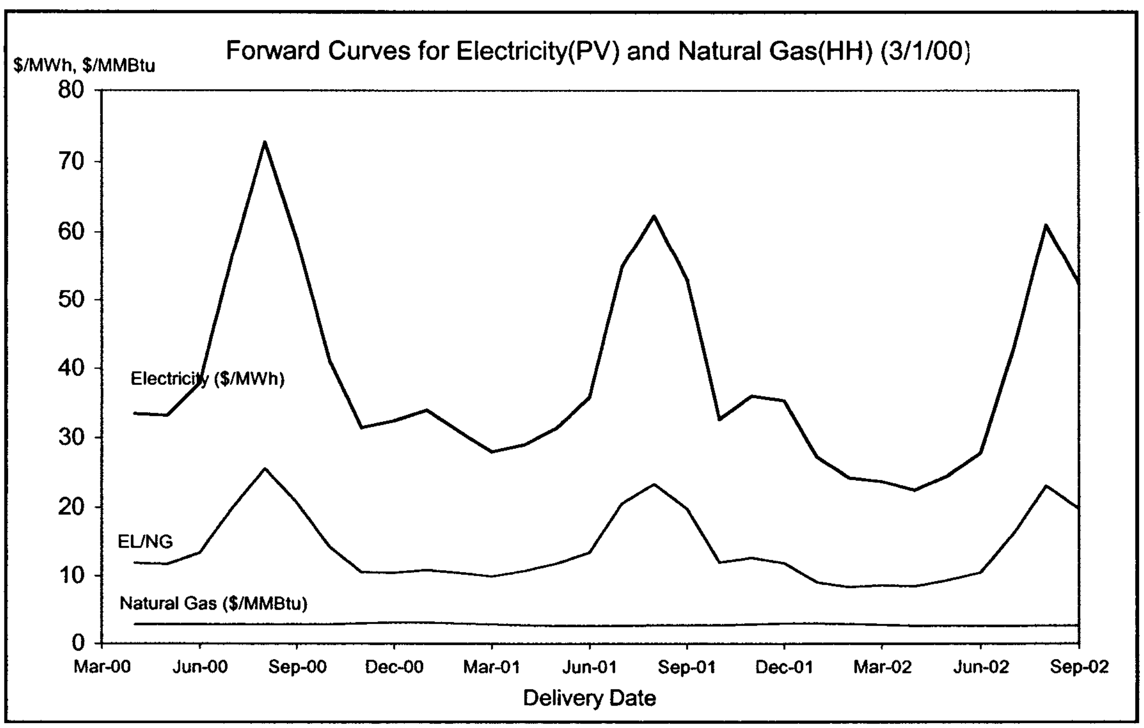
FIGURE 6: Spot Prices of Electricity in Southern California and the Price Caps. (Source, Energy Market Report and CAISO)



Q. CAN YOU EXPLAIN WHAT HAPPENED TO PRICES WHEN THE SOFT PRICE CAP WAS ENFORCED BY FERC?

A. The soft price cap made it easier for suppliers to sell above the cap in the Californian market. For example, most of the spot prices in southern California are above the soft price cap in Figure 6. Unfortunately for buyers in the market, the soft cap turned out to be a no cap market. Many of the spot prices were substantially above the previous hard cap of $250/MWh during the winter 2001. Getting prices of $300/MWh in the winter 2001 was an order of magnitude above the typical winter prices of $30/MWh in 2000. It was also very unfortunate for buyers that the period of high spot prices in the winter 2001 coincided with the period in which FERC had propelled buyers into the forward markets (one part of the same Order that established the soft price cap).

FIGURE 7, Forward Curves for Electricity



Q. TURNING TO THE THIRD ISSUE, HOW DID YOU INCORPORATE MARKET FUNDAMENTALS INTO YOUR ANALYSIS?

A. Figure 7 shows the forward price curves for electricity at Palo Verde and for natural gas at Henry Hub, based on quotations on March 1, 2000 (these forward prices are the prices that could be set in March 2000 for different monthly delivery dates in the future from April 2000 to September 2002). Hence, these forward curves represent market conditions before the market dysfunction that began in June 2000. Under normal conditions, each forward price corresponds to the expectations of market traders about the future spot price at the delivery date. Even though the forward price curve for natural gas is almost flat (unlike electricity, natural gas is slightly more expensive in the winter than the summer), the forward curve for electricity exhibits a strong seasonal cycle.

Q. WHY DO YOU OBSERVE A SEASONAL CYCLE FOR THE PRICE OF ELECTRICITY?

A. The seasonal cycle for the price of electricity represents different market fundamentals relating to the cost of operating the marginal generator. The high prices in the summer are roughly twice as high as the prices in the winter because relatively inefficient turbines (*i.e.* with high heat rates and high emission rates) are used to meet the high loads in the summer. For example, a combined cycle turbine – with an efficiency of 50% electric – may be the marginal generator in the winter, and a single-cycle jet engine – with an efficiency of 25% electric – may be the marginal generator in the summer.

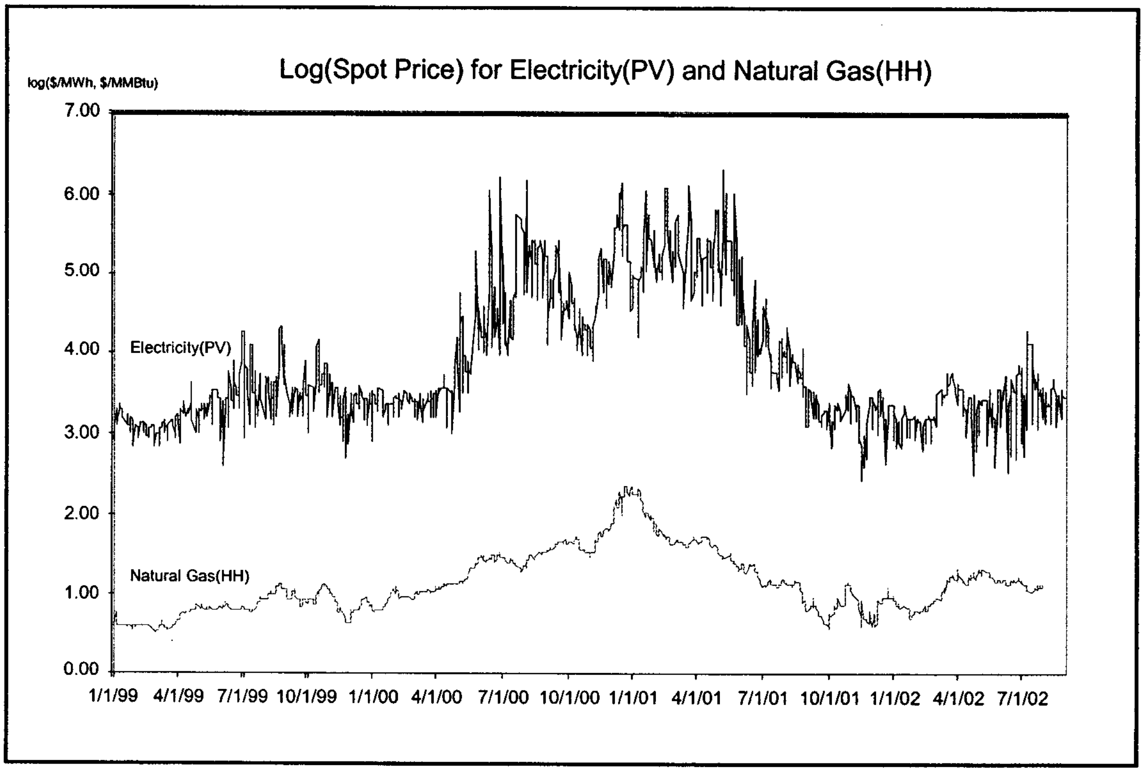
Q. HOW DID YOU USE THESE FORWARD PRICE CURVES TO MEASURE MARKET FUNDAMENTALS?

A. The ratio of the forward price of electricity to the forward price of natural gas (EL/NG) is also shown in Figure 7, and it exhibits the same seasonal cycle as the price of electricity. However, if the forward price of natural gas increased, one would expect the forward price of electricity to increase as well. Consequently, the price ratio represents a convenient way to capture the annual change of market fundamentals associated with the efficiency of the marginal generator for a given pattern of future prices of natural gas. The objective of my analysis is to explain the additional changes of this price ratio that occurred when the spot market for electricity was dysfunctional.

Q. HOW DID THIS PRICE RATIO CHANGE WHEN THE SPOT MARKET WAS DYSFUNCTIONAL?

A. Under normal conditions, the ratio of the forward price of electricity to the forward price of natural gas ranges from a low of roughly 10 in winter to a high of 25 in summer. The first step of the analysis was to estimate the typical seasonal patterns for the forward curves in Figure 7 using Sine/Cosine cycles with periods of one year and half a year. Regression models were fitted using the logarithm of the forward prices of electricity at Palo Verde and of natural gas at Henry Hub on March 2, 2000 as the two dependent variables (*i.e.* the logarithm of the price data shown in Figure 7). The estimated cycles were then used to predict the regular annual patterns of market fundamentals for the corresponding logarithms of the spot prices of electricity at Palo Verde and of natural gas at Henry Hub, shown in Figure 8.

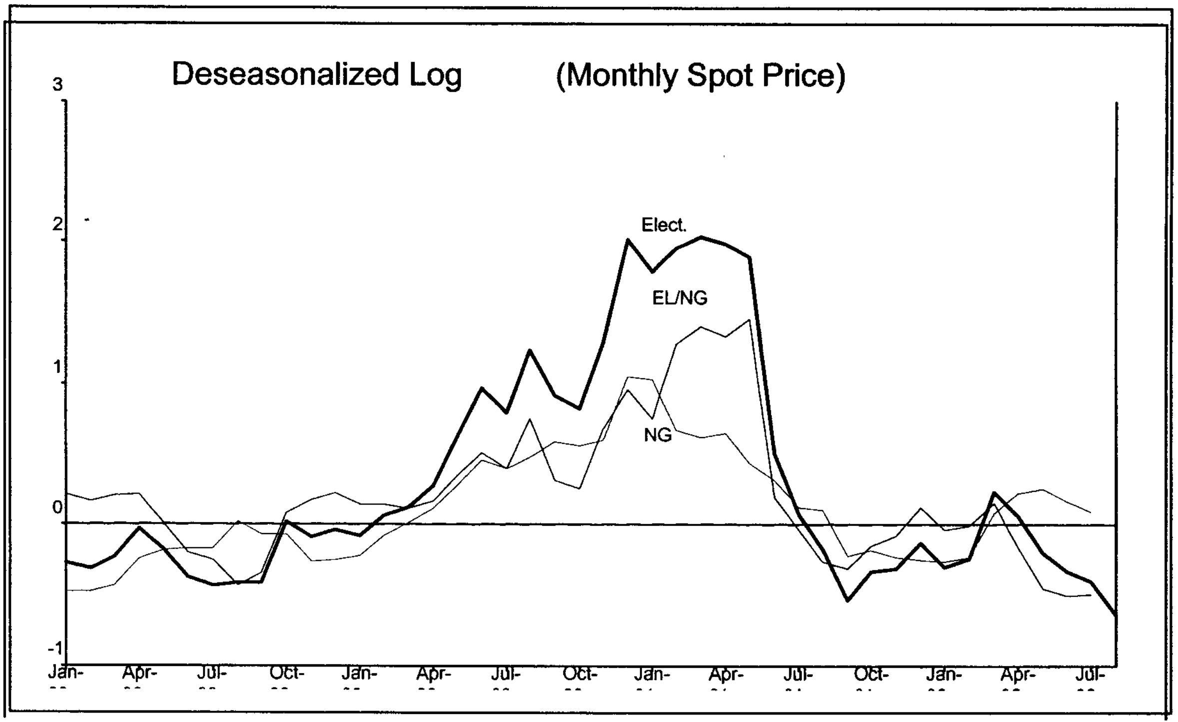
FIGURE 8: Spot Prices for Electricity at Palo Verde (PV) and Natural Gas at Henry Hub (HH) (Source, Energy Market Report and NYMEX)



Q. HOW DID YOU USE THE SEASONAL PREDICTIONS OF THE SPOT PRICES?

A. The differences between the observed spot prices and the predicted spot prices (both in logarithmic form) represent the "surprise" in the markets for electricity and natural gas. Since the prices have been transformed into logarithms, the equivalent surprise for the price ratio (in logarithms) is simply the difference between the surprise for electricity and the surprise for natural gas. The monthly averages of the estimated surprises in the spot markets for electricity and natural gas (more formally, the surprises correspond to the de-seasonalized spot prices) are shown in Figure 9.

FIGURE 9: Estimated Surprises in the Spot Markets for Electricity (PV) and Natural Gas (HH) and the Ratio (Source, Derived from data in Figures 7 and 8)



Q. WHAT IMPLICATIONS CAN YOU DRAW FROM FIGURE 9?

A. Since the spot prices have been converted to logarithms, one would expect the surprises to fluctuate around zero if conditions had remained normal after March 2000. This is because the forward prices in Figure 7 represent the expectations of traders about future spot prices. The surprises for both prices are consistently above zero from April 2000 to July 2001 in Figure 9, and this implies that both prices were higher than the levels expected under normal market conditions. Hence, the market participants were surprised by the increases of both the spot price of electricity and the spot price of natural gas during the period when the market was dysfunctional. Market conditions returned to normal in June 2001 when FERC imposed a system-wide price cap (see Figure 6).

Q. ARE THERE DIFFERENCES BETWEEN THE SPOT MARKETS FOR ELECTRICITY AND NATURAL GAS?

A. Yes. The surprises in the spot price for electricity were much larger (larger percentage increases above normal levels) because the surprises in the price ratio are also consistently above zero when the market was dysfunctional. If the unexpectedly high prices of electricity were caused by the unexpectedly high prices of natural gas, the ratio of the two prices would still fluctuate around zero. Figure 9 shows that this was definitely not the case. The main implication is that the unexpected increases in the spot price of electricity (in percent) were much larger than the corresponding increases for natural gas when the market was dysfunctional.

Q. CAN YOU DRAW ADDITIONAL CONCLUSIONS FROM FIGURE 9?

A. Yes. First, the surprises in the price ratio (EL/NG) were highest from January to May 2001. In other words, the highest unexpected spot prices for electricity occurred when the soft price cap was in effect (see Figure 6) and many forward contracts for electricity were being executed. Second, the surprises in the spot price of electricity (and the price ratio) decline very rapidly from May to July 2001. In contrast, the surprises in the spot price of natural gas declined relatively gradually from February to September 2001.

Q. HOW DO THE UNEXPECTEDLY HIGH PRICE RATIOS RELATE TO MARKET FUNDAMENTALS?

A. Obviously, the high prices of natural gas at Henry Hub are not the cause because these high prices have been taken into account in the ratio. Most of the arguments about the importance of market fundamentals in causing high prices for electricity in California discuss the conditions in the summer 2000. Since one expects prices of electricity to be high in the summer, the high spot prices in the summer 2000 were only a modest surprise compared to the high spot prices in the winter 2001. For example, the levels of the actual spot prices of electricity in Figure 5 are relatively similar in the summer 2000 and the winter 2001 compared to the corresponding levels of the surprises for electricity in Figure 9. I believe that the change to a soft price cap was an important contributing factor to the extraordinarily high spot prices of electricity, and the corresponding increase in uncertainty about market conditions, in the winter 2001. I have not seen a convincing alternative explanation.

Q. DO YOU HAVE ANY ADDITIONAL EVIDENCE SUPPORTING YOUR CONCLUSION ABOUT THE ADVERSE EFFECTS OF A SOFT PRICE CAP?

A. The main reason for reaching my conclusion is based on the results from research conducted at Cornell University. In this research, different types of auction used in deregulated markets for electricity have been tested in a laboratory setting. Our findings to date show that introducing price-responsive load, such as interruptible contracts, in a standard uniform price auction is a much better way to mitigate high prices than using a soft price cap (T.D.Mount, W.D.Shulze, R.J.Thomas and R.D.Zimmerman "Testing the Performance of Uniform Price and Discriminative Auctions", Working Paper, Cornell University, Presented at the Rutger's Center for Research in Regulated Industries 14th Annual Western Conference: Advanced Workshop in Regulation and Competition, Competitive Change in Network Industries, San Diego, California, June 2001). Using a soft price cap, the supply curve based on offers from suppliers is much flatter than it is in a typical uniform price auction. As a result, price-responsive load is less effective as a way to mitigate high prices, compared to a uniform price auction, which has a typical supply curve shaped like a hockey stick.

Q. WHAT IMPLICATIONS CAN YOU DERIVE ABOUT THE DYSFUNCTIONAL SPOT MARKET FOR ELECTRICITY?

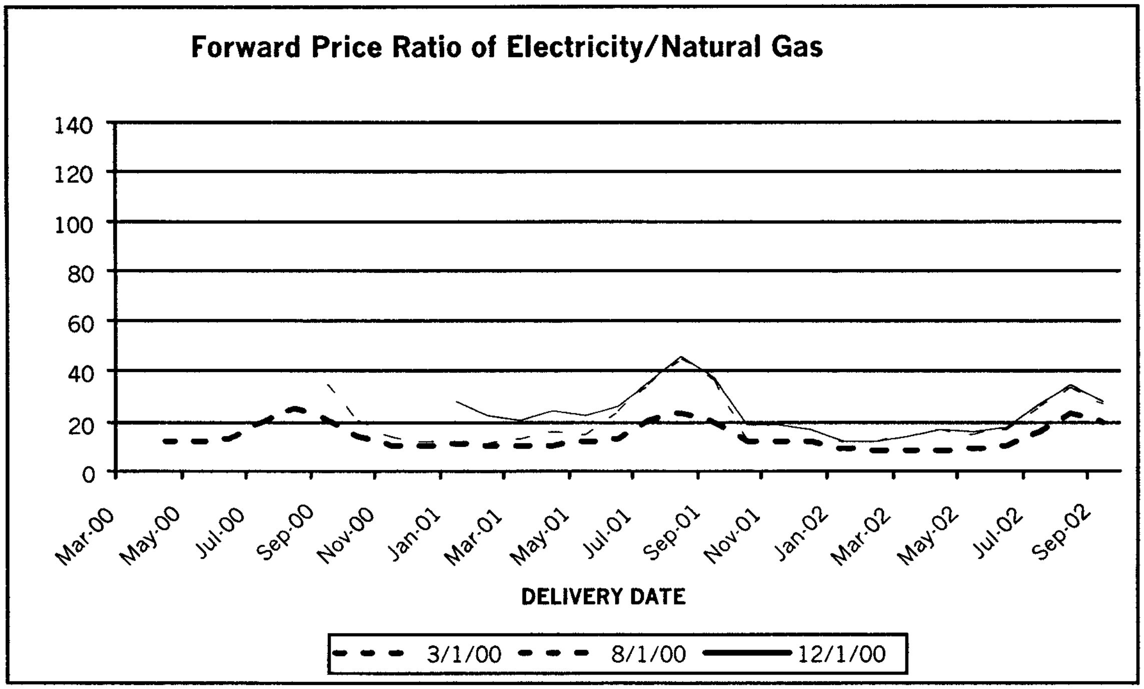
A. After evaluating the performance of the spot market for electricity in California during the summer of 2000, FERC concluded that the market was dysfunctional. This conclusion provided the rationale for making changes in the market structure that were implemented in the FERC Order of December, 2000, and included the replacement of a hard price cap by a soft price cap. The evidence presented in Figure 9, and particularly the large surprises in the price ratio (EL/NG), imply that the spot market for electricity was even more dysfunctional in the winter 2001 than it was in the summer 2000, and the winter 2001 was exactly the period when most of the contested forward contracts for electricity were executed. As soon as

FERC demonstrated a clear resolve to deal with the problem of high prices in the West by issuing the June 19, 2001 Order, the market returned to normal and much of the uncertainty about future prices disappeared (*i.e.* the surprises for the price of electricity in Figure 9 fluctuate around zero after June, 2001.)

Q. HOW DID THE FORWARD MARKET FOR ELECTRICITY AT PALO VERDE RESPOND TO THE SURPRISES IN THE SPOT MARKET?

A. To answer this question, I will discuss the ratio of the forward price of electricity to the corresponding forward price of natural gas. The reason for doing this is to remove the effects of higher prices of natural gas and focus on the additional factors that affect the price of electricity. The forward curves of the price ratios are shown for three different trading dates in Figure 10. The forward price ratios on the earliest trading date (March 1, 2000) are identical to the ratios (EL/NG) shown in Figure 7. The other two trading dates correspond to a date in the summer 2000 (August 1, 2000) when the spot prices of electricity were unexpectedly high, and a date just before the change to a soft-price cap in the spot market for electricity (December 1, 2000).

FIGURE 10: Forward Price Ratios of Electricity (PV) to Natural Gas (HH) for three trading dates before the Winter 2001. (Source, PacifiCorp and NYMEX)



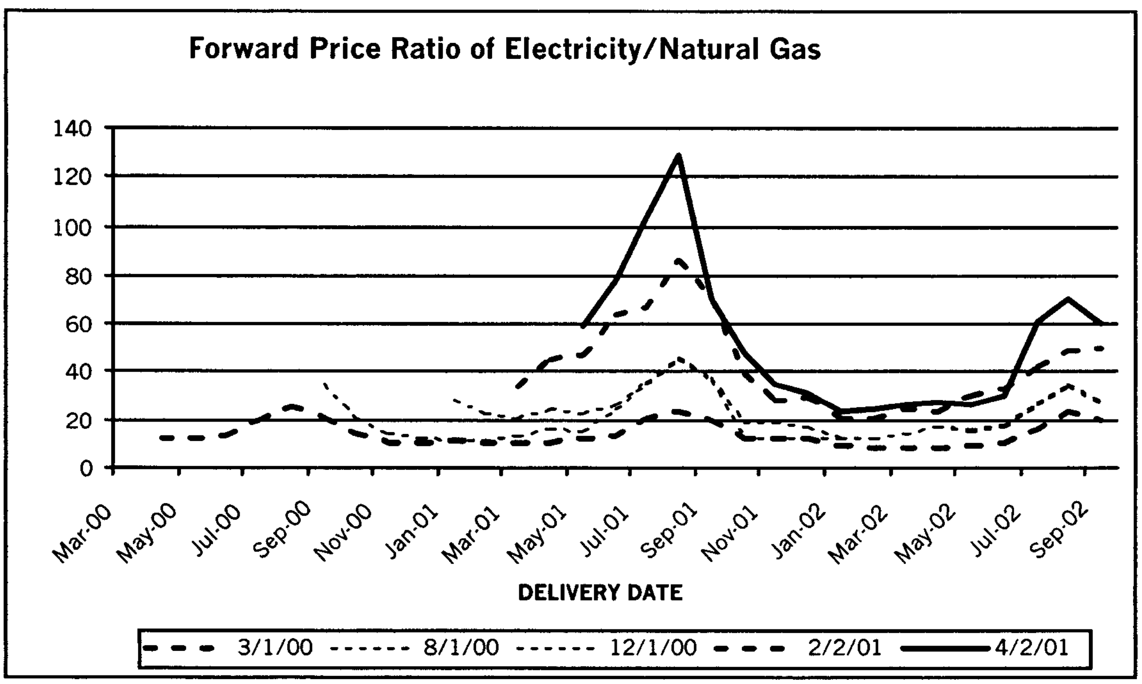
Q. WHAT CONCLUSIONS CAN YOU DRAW FROM FIGURE 10?

A. The high spot prices of electricity in the summer 2000 were interpreted as a summer problem, and forward price ratios for the winter 2001 and winter 2002 were similar to normal levels (*i.e.* the forward curve on August 1, 2000 increased in the summer months much more than in the winter months, relative to the normal conditions represented by the forward curve on March 1, 2000). There were few changes in the expectations of traders during the fall 2000 and the forward curves on August 1, 2000 and December 1, 2000 are almost identical for delivery dates after March, 2001. For earlier delivery dates, the forward curve for December 1, 2000 was higher because spot prices of electricity were unexpectedly high in the fall 2000 (see Figure 7). The main conclusion is that traders considered that the high spot prices of electricity in the fall 2000 were not a long-term problem, but the high prices in the summer 2000 were a problem that was likely to occur again in future summers.

Q. WHAT HAPPENED AFTER THE SOFT PRICE CAP WAS IMPLEMENTED IN DECEMBER 2000?

A. Spot prices of electricity were extraordinarily high as Figures 5, 6, 8, and 9 show. Figure 11 shows why the vertical scale goes to 140. The typical price ratios under normal conditions range from 10 to 25 (see Figure 7), but on April 1, 2001, the forward ratio reached 125 for the summer 2001 and over 70 for the summer 2002. Comparing the forward curves on February 2, 2001 and April 1, 2001 shows that the forward curves for delivery in future summer months increased during the winter 2001.

FIGURE 11: Forward Price Ratios of Electricity (PV) to Natural Gas (HH) for five trading dates before and during the Winter 2001(Source, PacifiCorp and NYMEX)



Q. HOW DO YOU INTERPRET THE RESULTS IN FIGURE 11?

A. During the winter 2001, traders came to believe that there were long-term problems with the market that were even more serious than the problems experienced in the previous summer. These new problems were not just a winter problem because the whole forward curve had shifted upwards to unprecedented levels.

Q. COULD HIGH PRICES FOR NATURAL GAS EXPLAIN THESE UPWARD SHIFTS IN THE FORWARD CURVES DURING THE WINTER 2001?

A. No. First, the forward curves represent the ratio of the forward price of electricity to the corresponding forward price of natural gas. Consequently, the ratio accounts for the higher prices of natural gas at Henry Hub. Second, even if one argued that the reported spot prices of natural gas for delivery in California are accurate (*i.e.* the prices in Figure 2), the unusually high differentials between Henry Hub and Southern California only lasted for one month (December 2000). (Southern California is the appropriate delivery point for Palo Verde in Arizona.) The reported prices of natural gas in Southern California are simply not high enough to explain the forward ratios on February 2, 2001 and April 1, 2001 shown in Figure 11. The typical ratios for the summer reach 25 (*see* Figure 7). Getting a ratio of 125 in Figure 11 implies the delivered price of natural gas in California would have to be five times higher than the price at Henry Hub. Even if one assumes the price at Henry Hub was only $5/MMbtu, and actual prices were considerably higher (*see* Figure 8, note that Log [5]=1.61), this would imply that delivered prices in California would have to be persistently above 5X5=$25/MMbtu during the winter 2001. As Figure 2 shows, this was not the case in either Southern or Northern California.

Q. WHAT IS YOUR EXPLANATION OF THE HIGH FORWARD RATIOS ON FEBRUARY 2, 2001 AND APRIL 2, 2001 IN FIGURE 11?

A. Traders believed that the spot market for electricity was truly dysfunctional and that the spot prices of electricity would continue to be abnormally high into the future. Furthermore, both FERC and the California state government had done little to reestablish confidence in the market at that time. Compounding the concerns of traders, Pacific Gas and Electric ("PG&E") filed for bankruptcy during the winter 2001, the first major electric utility to do so in the history of the industry. Companies with commitments to serve customers, such as PacifiCorp, must have viewed this bankruptcy as a very ominous omen for the future. Any utility that continued to buy high in the spot market and sell low at regulated rates to customers would end up in the same predicament at PG&E. As Dr. Oren explained in his Direct Testimony at Exhibit PAC-11, buyers in the spot market with commitments to customers were exposed to unacceptably high levels to risk (*i.e.* the sky is the limit for the purchasing price and for losses).

Q. WHY ARE THE LEVELS OF RISK LOWER FOR SUPPLIERS?

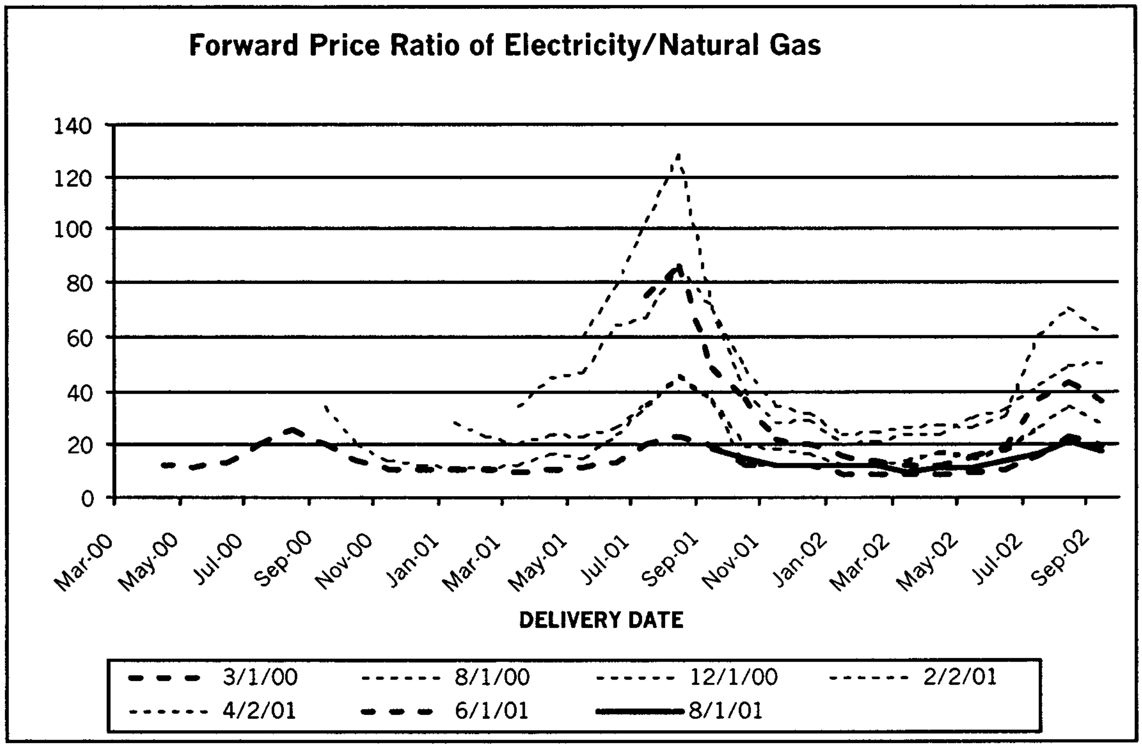
A. Suppliers have a built-in call option when they own a generator. Suppliers do not have to sell if the spot price is below their marginal cost (*i.e.* operating profits do not fall below zero in the spot market for suppliers). This asymmetry of risk is favorable to suppliers compared to buyers when forward contracts are made. More uncertainty about future spot prices will tend to make the risk premium higher in a forward contract. As a result, forward prices for electricity in a dysfunctional spot market are likely to be much higher than the true statistical expectation of the future spot price. The risk premium is the main reason why the forward ratios in Figure 11 on February 2, 2001 and April 2, 2001 are so abnormally high.

Q. WHAT HAPPENED TO THE FORWARD PRICE RATIO AFTER APRIL 2001?

A. Figure 12 shows two additional forward curves for the price ratio as well as the forward curves shown in Figure 11. The forward curve on June 1, 2001 had shifted down from the forward curve on April 1, 2001, but the ratios for the next two summer months in 2001 were still high (over 70) even though the ratios for the coming winter were back to normal. The ratios for the following summer 2002 reach 40 and are similar to the corresponding ratios that were expected a year earlier during the previous summer on August 1, 2000. In other words, traders still expected the market to have problems in the summer months, but they believed that conditions would return to normal in the winter months. When the actual spot prices of electricity continued to fall in the summer 2001 (*see* Figure

8), traders believed the problem in the summer had also been solved. The forward curve on August 1, 2001 has essentially returned to the original forward curve on March 1, 2000 when market conditions were normal and traders expected the conditions to remain normal.

FIGURE 12: Forward Price Ratios of Electricity (PV) to Natural Gas (HH) for seven trading dates before, during and after the Winter 2001. (Source, PacifiCorp and NYMEX)



Q. HOW WOULD YOU SUMMARIZE THE BEHAVIOR OF THE FORWARD PRICE RATIOS DURING THE PERIOD WHEN THE SPOT MARKET WAS DYSFUNCTIONAL?

A. There were two different types of dysfunction in the spot market for electricity. The high prices in the summer 2000 were interpreted by traders as a summer problem only. In contrast, the high spot prices in the winter 2001 were interpreted by traders as a much more serious problem that would persist and affect future prices in all months. By the end of the winter 2001, forward prices for delivery in the summer months reflected the combination of both types of dysfunction, experienced in the summer 2000 and the winter 2001. When a hard price cap was enforced by FERC in June, 2001, FERC effectively eliminated the uncertainty about high prices associated with the problems in the winter 2001. By August 2001, the low spot prices of electricity convinced traders that the problems of the previous summer had also been mitigated.

Q. HAVE YOU DONE ANY ADDITIONAL ANALYSIS OF THE FORWARD PRICES OF ELECTRICITY?

A. Yes. I have estimated regression models to show how well the surprises in the spot markets explain the changes in the ratio of the forward price of electricity at Palo Verde to the forward price of natural gas at Henry Hub. These models represent a more comprehensive analysis than the two models presented in my testimony, but the general conclusions remain the same. The models provide a confirmation of the explanation, given above, of the observed changes in the forward curves in Figures 10-12. The two models presented in my testimony explain changes in the forward price ratios for delivery in two months only, August 2001 and August 2002. The new models (1) use better data for forward prices obtained from PacifiCorp, (2) have an improved structure that is more consistent with economic principles, and (3) explain changes in the forward price ratios for every month from June 2001 to August 2002.

Q. CAN YOU DESCRIBE THE NEW MODELS?

A. For any one of the fifteen different delivery months, the structure of the model is the same, although the values of the coefficients for each month are different. In fact, the coefficients change as the delivery date changes in the different models in an interesting and systematic way. The basic structure of the model allows the forward price to converge towards the spot price as the trading date gets closer to the delivery date. The earliest delivery date for each forward curve in Figures 10-12 represents the forward price ratio for one month ahead (for example, the first value for the forward curve on March 1, 2000 gives the price for delivery in April 2000). The forward prices for electricity or natural gas one month ahead will be relatively close to the spot prices under normal circumstances.

Q. HOW DID YOU INCORPORATE THIS FEATURE INTO THE MODEL?

A. Each model uses a weighted average of an adjusted spot price ratio (really a simple forecast of the forward price using the current spot price ratio corrected for seasonal effects) and a function of the surprises in the spot market. The weights of both components of the model add to one (and are never negative). The weight for the adjusted spot price ratio increases to one as the trading date gets closer to the delivery date. At the same time, the weight for the surprise function goes to zero. This structure was specified to capture the economic principle that the forward price should converge to the spot price when the trading date approaches the delivery date. More detail about the form of the weights is given in Table 1.

However, from an empirical perspective, the effect of the surprise function is completely dominant until the last two or three months before delivery.

Q. CAN YOU DESCRIBE THE STRUCTURE OF THE SURPRISE FUNCTION?

A. The form of the function is similar to the form used in my testimony that allows for a gradual adjustment of the forward price ratio to surprises (using a distributed lag model). The main difference is that the surprises for the spot price of natural gas are included in the model as well as the surprises for the spot price of electricity. In other words, the forward price ratio for a fixed delivery month (the dependent variable, in logarithmic form) is specified as a function of the two price surprises for electricity and natural gas (shown in Figure 9) and the value of the dependent variable in the previous month (the lagged dependent variable). The price surprises are also lagged by one month because the specified trading dates correspond to the first trading day of each month. The surprises are determined by the actual experiences of traders in the spot markets during the previous month (with seasonal effects removed). All three explanatory variables and an intercept are multiplied by the appropriate weight (the one that goes to zero as the trading date approaches the delivery date). For each trading date, the appropriate monthly data are used to estimate the coefficients of the explanatory variables using the statistical package SAS.

Q. CAN YOU DESCRIBE THE RESULTS?

A. The models fit the data very well and the statistical properties are sound, particularly for delivery in the summer months. All of the R-squared are greater than 83% (a perfect fit is 100%), and five of the six models for the summer months have R-squared greater than 90%. The main conclusion is that surprises in the spot markets for electricity and natural gas do explain the observed changes in the forward price ratios for different delivery dates during the period when the spot market for electricity was dysfunctional.

Q. ARE THERE DIFFERENCES IN THE EFFECTS OF THE SURPRISES IN THE SPOT MARKETS FOR ELECTRICITY AND NATURAL GAS?

A. Yes. The estimated effects of the two sources of price surprise in the spot markets vary systematically for the fifteen different delivery months. The estimated coefficient for each price surprise measures the percentage increase in the forward price ratio of electricity to natural gas in response to a one percent increase in the surprise in the spot prices of electricity or natural gas (i.e. the short-run elasticity).

Q. **HOW DO YOU INTERPRET THE VALUES OF THE ESTIMATED COEFFICIENTS FOR ELECTRICITY AND NATURAL GAS IN TABLE 1?**

A. First, these new results are consistent with the results for the models presented in my original testimony. The models in Table 1 for delivery in August, 2001 and August, 2002 imply that the effects of surprises in the spot price of electricity are important and positive, and the corresponding effects for natural gas are insignificant and negative. In other words, the surprises in the spot market for electricity are the primary determinants of the high forward prices of electricity. My original conclusion was that large proportions of the variability in the forward price ratios for August, 2001 and August, 2002 could be attributed to surprises in the spot market for electricity (spot prices of natural gas were not included in the original models). Hence, the new and old models are consistent with each other with respect to delivery in the summer months. However, for delivery in the winter months of 2002, surprises in the spot market for natural gas are more prominent than the corresponding surprises for electricity.

Q. CAN YOU SUMMARIZE THE EFFECTS OF THE PRICE SURPRISES FOR ELECTRICITY IN THE NEW MODELS?

A. Since one would expect that abnormally high prices for electricity (i.e. large positive price surprises) would have a positive relationship with the forward price of electricity, the positive coefficients for the electricity surprise are consistent with this expectation. Part of this positive effect represents a risk premium associated with the uncertainty of a dysfunctional market. The coefficients are larger for the summer months. This is consistent with the seasonal cost patterns of producing electricity, because load is high in the summer and generating capacity is relatively scarce in the summer compared to the winter.

Q. HOW DO THE EFFECTS OF THE PRICE SURPRISES FOR ELECTRICITY AND NATURAL GAS DIFFER FROM EACH OTHER?

A. The effects of the price surprises for natural gas are more difficult to explain because the coefficients in the model change sign for different delivery dates. Using the same logic for natural gas as the explanation already given for electricity, one would expect that the coefficients of the price surprises for natural gas should be negative (the dependent variable is the logarithm of the ratio of the forward price of electricity to the forward price of natural gas, implying that the coefficients for electricity and natural gas should have opposite signs). The estimated coefficients for natural gas in Table 1 have the expected negative sign for delivery in all summer months except June, 2002. However, the coefficients are positive for delivery dates in the winter and spring months in 2002.

Q. WHY ARE THE COEFFICIENTS FOR NATURAL GAS POSITIVE FOR SOME DELIVERY MONTHS?

A. The largest price surprises for natural gas occurred in December, 2000 and January, 2001 (see Figure 9). These two months also coincided with the reports of even higher prices of natural gas delivered in California (see Figure 2). Consequently, the positive coefficients for natural gas represent a higher risk premium for forward prices of electricity due to the increased uncertainty about the reliability of supplies of natural gas in California.

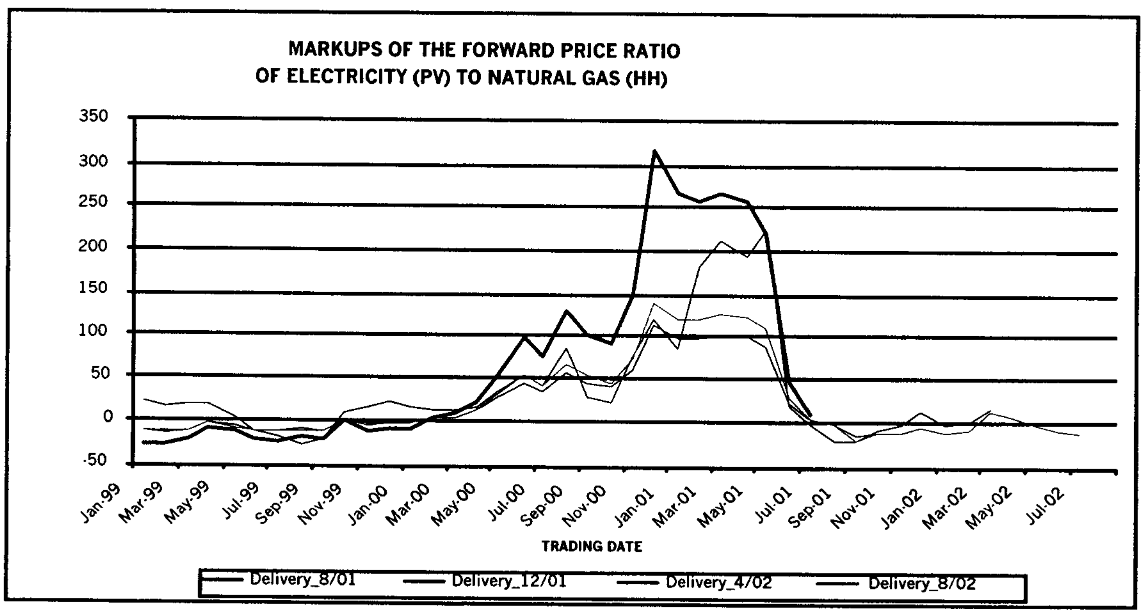
Q. CAN YOU SUMMARIZE THE RESULTS OF THE MODELS IN TABLE 1?

A. The most important conclusion is that there are two sources of dysfunction in the spot markets which contributed to higher prices in the forward market for electricity. The first source is the uncertainty associated with the performance of the spot market for electricity when the soft price cap was in effect. This relationship represents the increased financial risk of the dysfunctional spot market for electricity, and this source of risk disappeared when FERC enforced a hard price cap throughout the Western Inter-Connection in June 2001 (see Figure 9). The second source of uncertainty is reflected by the positive relationships between the price surprise for natural gas and the forward price of electricity for delivery in the winter and spring of 2002. This relationship represents the increased financial risk of restrictions on the physical supply of natural gas to California that occurred in the Winter, 2001. The increased uncertainty in the spot markets for electricity and natural gas both contributed to higher risk premiums in the forward prices for electricity during the period when the spot market for electricity was dysfunctional (May 2000 to June 2001).

Q. CAN YOU SHOW HOW THE PRICE SURPRISES AFFECTED THE FORWARD PRICE RATIO IN THE MODELS?

A. Yes. The estimated coefficients in Table 1 give the appropriate weights for the two different types of price surprise shown in Figure 9. Multiplying each coefficient by the level of the price surprise and adding the two effects together measures the combined effect of the price surprises on the logarithm of the forward price ratio of electricity to natural gas. This can be adjusted for the gradual adjustment process and converted to the percentage difference from normal (note, if both coefficients are zero or both price surprises are zero, the percentage difference from normal would also be zero). Hence, the computed value represents the estimated percentage change in the forward price ratio caused by the dysfunctions in the spot markets.

FIGURE 13: Estimated Percentage Markups of the Forward Price Ratio of Electricity (PV) to Natural Gas (HH) due to Dysfunctions in The Spot Markets
(Source, Derived from the data in Figure 9 and the coefficients in Table 1)



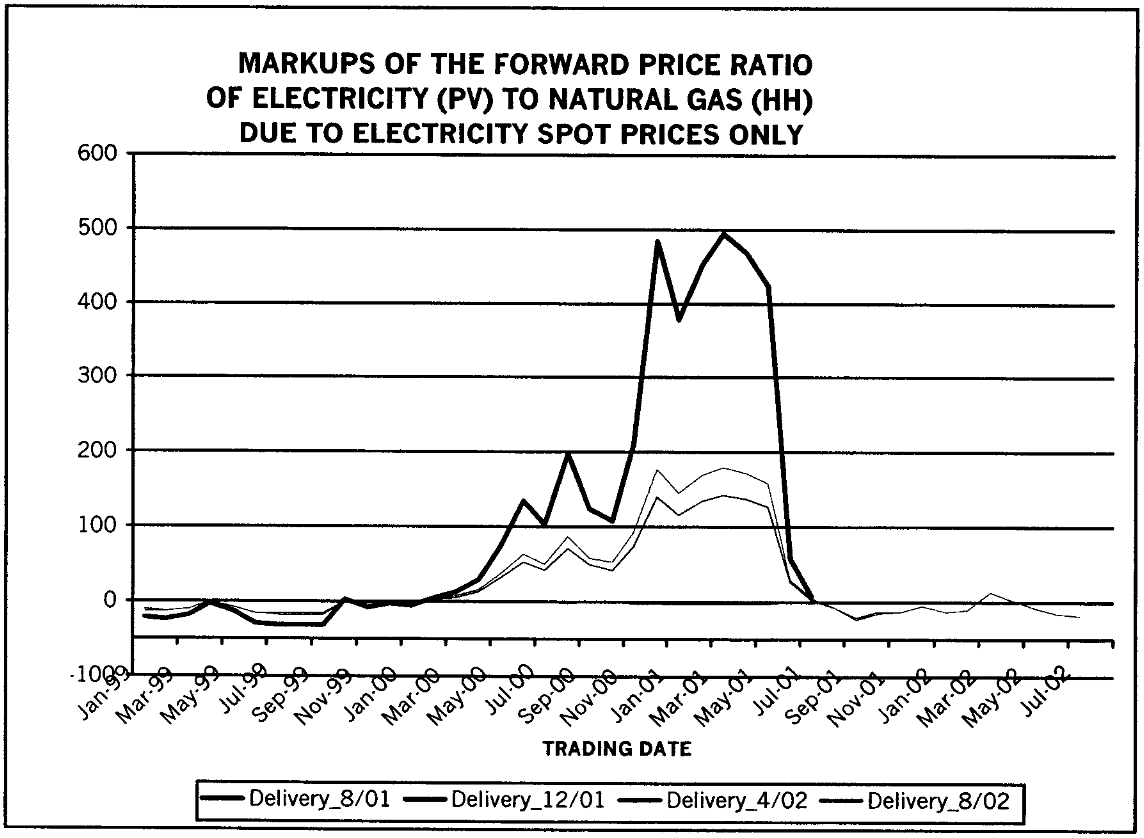
Q. HOW BIG WERE THE PERCENTAGE DIFFERENCES FROM NORMAL CONDITIONS?

A. Figure 13 shows the estimated values of the percentage markups from normal for four different delivery dates (August 2001, December 2001, April 2002 and August 2002), These four delivery dates represent different seasons of the year and are representative of the full range of models in Table 1. The estimated percentage markups from normal are very small for trading dates prior to May 2000 because there were no major price surprises at that time. During the period of dysfunction in the spot markets (May 2000 to June 2001), the estimated markups are very large, particularly for the two summer delivery dates. However, the estimated markups began declining in May and returned to normal after the system-wide hard price cap was imposed in June, 2001. The estimated markups remained at normal levels after June, 2001. The traders believed that the problems in the spot markets had been solved and there were indeed no more price surprises in the spot markets.

Q. HOW MUCH OF THE HIGH ESTIMATED MARKUPS IN FIGURE 13 CAN BE ATTRIBUTED TO THE SPOT PRICE OF ELECTRICITY?

A. For delivery months in the summers of 2001 and 2002, the markups determined exclusively by the price surprises for electricity are very large. The corresponding effects are smaller for the delivery in the winter of 2002. The estimated percentage markups of the forward price ratio determined by the price surprises for electricity only are shown in Figure 14. It should be noted that these percentage markups also measure the percentage change from normal levels of the forward price of electricity conditional on the corresponding forward price of natural gas.

FIGURE 14: Estimated Percentage Markups of the Forward Price Ratio of Electricity (PV) to Natural Gas (HH) due to the Spot Price of Electricity (Source, Derived from the data in Figure 9 and the coefficients in Table 1)



Q. CAN YOU SUMMARIZE THE RESULTS IN FIGURES 13 AND 14?

A. The dysfunctional features of the spot markets (i.e. abnormally high spot prices for electricity and the uncertainty about supplies of natural gas) were transferred to the forward market for electricity to give abnormally high forward prices. These abnormally high forward prices persisted through the Winter, 2001 during a period when many new forward contracts for electricity were being executed. Hence, the abnormally high prices in these contracts were the result of the dysfunctional spot markets. Notably, for purposes of this case, Figure 14 demonstrates that electricity spot prices had a significant impact on forward electricity prices. The pattern of forward prices for electricity returned to normal levels soon after FERC enforced a hard price cap throughout the Western Inter-Connection. The new price cap effectively removed the major sources of financial risk associated with the dysfunctional spot market for electricity.

Q. IS THIS THE END OF YOUR TESTIMONY?

A. Yes, it is.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	
Complainant,	)	
v.	)	
	)	
Reliant Energy Services, Inc.,	)	**Docket No. EL02-80-000**
Morgan Stanley Capital Group Inc.,	)	**Docket No. EL02-81-000**
Williams Energy Marketing & Trading	)	**Docket No. EL02-82-000**
Company, and	)	**Docket No. EL02-83-000**
El Paso Merchant Energy, L.P.	)	
Respondents.	)	**(consolidated)**

AFFIDAVIT
OF
Dr. TIMOTHY MOUNT

Dr. Timothy Mount, on oath, deposes and states that the foregoing Affidavit and Exhibits, on behalf of PacifiCorp were prepared by him or at his direction and under his supervision, and that if asked the questions herein, he would give the answers as shown, and that the facts stated herein are true to the best of his knowledge, information and belief.

Dr. Timothy Mount

Subscribed and sworn to before me on this 23rd day of November , 2002

NOTARY PUBLIC
My Commission Expires:

RACHEL A. CLARKSON
Notary Public, State of New York
No. 01CL6060884
Qualified in Tompkins County
Commission expires July 2, 2003

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