1998 MARKET CLEARING PRICE FORECAST FOR THE CALIFORNIA ENERGY MARKET: Forecast Methodology and Analytical Issues

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I. INTRODUCTION

The Market Clearing Price (MCP) refers to the price of electricity sold into the California Power Exchange (PX). The California PX accepts and creates a balanced schedule of supply and demand bids from generators and consumers in a day-ahead market. The last bid accepted for providing generation in a particular hour sets the MCP that the PX pays to all generators providing electricity in that hour. [1]

This MCP Forecast updates Staff's December 10, 1997 Interim Forecast.[2] The December 10, 1997 Forecast was designated as "interim" since it relied on the **Interim** 1997 Fuels Report (FR 97) Gas Price Forecast. The present forecast uses the **Final** FR 97 Gas Price Forecast. Although gas prices have not changed significantly, a number of other modeling inputs were revised and are described in the report.

Section II summarizes our findings with respect to a comparison of our interim and final forecasts to the actual PX prices to date; the factors that contribute to major uncertainty in the forecast; and the income earning prospects for in-state gas-fired generators.

Section III provides the new MCP Forecast and the methodology used. This section also provides a comparison of actual PX prices to our forecasted values, and examines the factors that we believe contributed to actual prices deviating from our forecasted values. Section IV describes market uncertainties and assumptions. Staff recommends reviewing both these sections carefully before using this forecast for any investment-related or revenue-forecasting purpose. Section V identifies personnel whom you can contact regarding questions about the MCP Forecast, including their phone and fax numbers and e-mail addresses. Section V also provides a list of vendors whose models were used in this and the previous forecast.

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[1] The California PX also conducts an hour ahead market to secure additional electricity given revisions in demand and unit availability. This forecast reflects the constrained hour ahead market. The modeling assumes no demand uncertainty and no forced outages after unit commitment.

[2] *Interim Staff Market Clearing Price Forecast for the California Energy Market: Forecast Methodology and Analytical Issues*, by Joel B. Klein. This is available on the Energy Commission's Web site: www.energy.ca.gov/papers (67 pages) or upon request as explained in Section V of this document.

II. SUMMARY OF FINDINGS

Staff's 1998 forecast differs only slightly from the 1997 forecast. The forecasted annual MCP for 1999 is 5 percent lower in the new forecast. For all other years, the difference between the two forecasts of the annual MCP is no more than 1.2 percent.

In 1999, the forecasted MCP declines in real dollars from its 1998 level (from $26.1 to $24.1 per megawatt-hour (MWh)) due to lower gas prices. The MCP doesn't return to 1998 levels until 2002, primarily because of the need to add new capacity. In 2002, the cost of a new market entrant sets the MCP. The real price of gas to electric generators in California does not return to 1998 levels until about 2012.

In May and June 1998, actual PX MCPs were significantly lower than those forecasted by staff. In the months of July, August, and September 1998 the PX MCPs were significantly higher than those forecast. The principal reason for these differences is that staff's modeling assumes average or expected conditions in terms of temperature, demand and hydro resource availability. In 1998, hydro availability was higher than expected and summer peak temperatures greater than average. These extreme conditions help to define both the levels of risk and opportunity that generators face in terms of revenue.

Other modeling assumptions that contributed to forecasted MCPs differing from the actual PX MCP include the following:

- Staff's modeling of the California PX market assumes a mature market with full participation by generators in-state and by generators out-of-state to the extent that unused generation and transmission capacity are available.

- The modeling also assumes that all available generation and Investor Owned Utility (IOU) load is bid into the PX day-ahead energy market. In reality not all generation and IOU load is bid into the PX day-ahead market. Direct access load and generation is not part of the PX market. Generation and demand can be bid into the ISO imbalance market. Generators also have other revenue making opportunities in the ISO's ancillary services market. The presence of price caps in some of these markets influences where generation and load is bid.

- Staff's modeling relies on historical utility load shapes. These historical shapes include the demand of industrial customers that is now being met through direct access contracts. Because direct access loads are not part of the PX market, the load factor of the actual PX market will be lower than the load factor implicit in the historical utility loads. This means that the load shape of demand in the PX market should have a more pronounced peak.

Two factors contributing a great deal of uncertainty to forecasting MCPs are: the extent to which the ISO relies upon and utilizes reliability must-run (RMR) contracts, and the future pace and extent of deregulation for states outside of California.

- RMR contracts directly affect when a fairly significant amount of capacity, currently 16,200 megawatts (MW), will be bid into the PX energy market. The longer these agreements stay in place, the less transparency there is in the market, and the more ambiguous the price signals that it conveys.

- As long as out-of-state generators remain under traditional regulation, they will have a competitive advantage in the California PX because they can bid their incremental cost of generation, which recovers just their variable O&M costs, while their fixed capital costs are recovered in their regulated rates. This has the effect of placing a ceiling on the bids of generators that have to recover their fixed capital costs from the PX energy market. The impact of this assumption is especially strong during the low load spring and autumn months when the amount of surplus capacity outside California is greatest.

From observing both the actual PX prices and our forecasted prices, it is clear that during the spring-runoff months and low-load autumn months it will be extremely difficult for in-state gas-fired generators to make money. These generators can hope to make up for these losses by earning more than their operating cost during the peak summer periods and the low hydro availability winter months, as well as by earning additional revenue in the ISO real-time balancing and ancillary services markets.

III. MARKET CLEARING PRICE FORECAST

Table 1 presents the Energy Commission Staff's 1998 and 1997 Annual Average MCP Forecasts, in both nominal (current) and real (constant) 1998 dollars. Figures 1A and 1B summarize the 1998 data in graphical format.

Table 1: MCP FORECAST

ANNUAL MCP ($/MWh)					
	December 1998 Forecast		December 1997 Forecast		
YEAR	NOMINAL	1998$	NOMINAL	1998$	% DIFF
1998	26.1	26.1	27.2	27.2	4.2
1999	24.7	24.1	25.9	25.3	5.0
2000	26.5	25.2	26.6	25.3	0.4
2001	27.8	25.6	27.3	25.3	-1.2
2002	29.6	26.6	29.3	26.3	-1.1
2003	30.6	26.7	30.3	26.4	-1.1
2004	31.9	26.9	31.6	26.7	-0.7
2005	33.1	27.0	32.8	26.8	-0.7
2006	34.5	27.3	34.3	27.1	-0.7
2007	36.0	27.4	35.7	27.2	-0.7
2008	37.5	27.6	37.3	27.4	-0.7

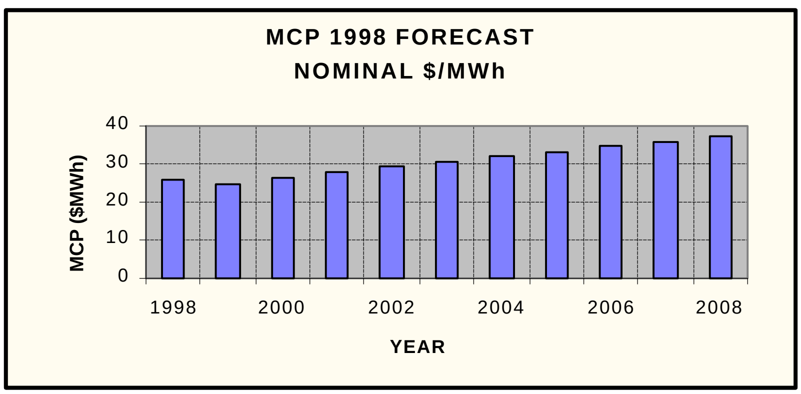

Figure 1A

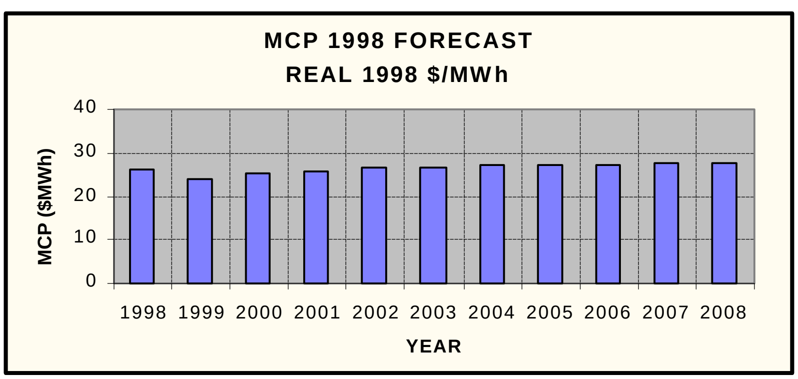

Figure 1B

As is shown in Table 1, the MCP starts in 1998 at about 26 $/MWh, reflecting actual market PX market data for April through November and UPLAN forecasted data for December. The MCP then falls in 1999, reflecting the effect of declining natural gas prices, as transportation facilities become available for the vast gas resources of the Gulf of Mexico. In real terms, gas prices do not return to their 1998 level until 2012.

Monthly and Sub-Period MCPs

Table 2 provides monthly sub-period data for the Energy Commission Staff's 1998 MCP Forecast. This data is provided for the years 1998 through 2001, the years for which UPLAN data is used. The MCPs for April through November of 1998 are actual PX data. On-peak is defined as 8 a.m. to 10 p.m.. Off-peak is defined as 11 p.m. to 7 a.m..

This MCP Forecast is an average for the entire state. We have not provided separate MCPs for the two Independent System Operator (ISO) congestion management zones (Northern California and Southern California). Zonal price differences are a complex function of both fuel prices -- most importantly gas prices -- and transmission congestion, in and out-of-state. Staff believes that, even if there are different MCPs for the two zones during certain hours, the difference will disappear over time. If prices are temporarily higher in one zone, then new entrants will enter that zone, thus reducing the MCP until it is essentially equal to that of the other zone. Staff, therefore, has elected to forecast one statewide MCP. Hourly MCPs for the years 1998-2001 for each month and for an average weekday and weekend day are provided in Appendix B. Monthly and hourly MCP prices for the entire forecast period of 1998-2008 are available in an EXCEL spreadsheet format that can be downloaded from the Commission website.

Table 2
MARKET CLEARING PRICE
By Time Period
Average Weekday and Weekend Day
(Nominal $/MWh)

Year	January		February		March		April (actual)		May (actual)		June (actual)	
1998	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**
AVG							23.7	19.8	13.9	6.8	13.0	9.2
Pk							27.5	21.9	18.4	8.6	18.3	12.7
OP							17.4	16.4	6.5	3.9	4.3	3.4
Year	**July (actual)**		**August (actual)**		**September (actual)**		**October (actual)**		**November (actual)**		**December (forecast)**	
1998	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**
AVG	34.9	26.7	44.5	28.7	36.1	27.6	28.1	23.1	26.7	23.3	30.2	26.2
Pk	43.6	32.0	56.5	32.6	43.4	30.3	31.4	25.8	29.6	25.8	33.6	29.1
OP	20.5	17.7	24.5	22.1	24.0	23.1	22.6	18.6	22.0	19.3	24.5	21.5

Year	January		February		March		April		May		June	
1999	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**
AVG	28.6	24.9	25.7	22.4	24.5	21.4	22.7	17.9	22.6	13.0	21.0	11.8
Pk	31.8	27.6	28.6	24.8	27.3	23.7	26.1	20.3	30.3	16.9	29.2	16.5
OP	23.2	20.3	20.9	18.3	19.9	17.5	17.0	13.8	9.9	6.5	7.4	4.1
Year	**July**		**August**		**September**		**October**		**November**		**December**	
1999	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**	**Week -day**	**Week -end**
AVG	27.3	18.6	36.7	24.0	32.5	23.0	23.7	20.3	24.6	21.4	27.7	24.1
Pk	34.2	22.2	46.5	27.7	39.0	24.9	26.6	22.8	27.4	23.8	30.9	26.8
OP	15.7	12.6	20.5	17.7	21.6	19.9	18.9	16.0	20.0	17.6	22.5	19.8

On-peak hours (8a.m. to 10p.m.)
Off-peak hours (11p.m. to 7a.m.)

Table 2 (cont.)
MARKET CLEARING PRICE
By Time Period
Average Weekday and Weekend Day
(Nominal $/MWh)

Year	January		February		March		April		May		June	
2000	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end
AVG	28.7	25.0	28.4	24.7	24.8	21.6	22.7	17.9	22.7	13.0	21.9	12.4
Pk	32.0	27.7	31.6	27.4	27.6	23.9	26.1	20.4	30.3	16.9	30.5	17.2
OP	23.3	20.5	23.0	20.2	20.1	17.7	17.0	13.9	9.9	6.5	7.7	4.3
Year	July		August		September		October		November		December	
2000	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end
AVG	27.6	18.8	44.6	29.1	38.8	27.5	26.4	22.6	26.6	23.1	27.9	24.3
Pk	34.6	22.5	56.4	33.6	46.7	29.8	29.6	25.4	29.6	25.7	31.1	26.9
OP	15.9	12.7	24.9	21.5	25.8	23.7	21.0	17.8	21.6	18.9	22.6	19.9

Year	January		February		March		April		May		June	
2001	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end
AVG	29.8	25.9	27.8	24.2	26.4	23.0	23.3	18.4	23.9	13.7	23.8	13.4
Pk	33.1	28.7	30.9	26.8	29.4	25.5	26.8	20.9	31.9	17.8	33.1	18.7
OP	24.1	21.2	22.5	19.8	21.4	18.8	17.4	14.2	10.4	6.8	8.3	4.7
Year	July		August		September		October		November		December	
2001	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end	Week -day	Week -end
AVG	31.1	21.2	49.1	32.0	38.3	27.2	27.4	23.4	27.6	24.0	28.9	25.2
Pk	39.0	25.3	62.1	37.0	46.0	29.4	30.8	26.3	30.7	26.6	32.2	27.9
OP	17.9	14.3	27.4	23.7	25.5	23.4	21.8	18.5	22.3	19.6	23.4	20.6

On-peak hours (8a.m. to 10p.m.)
Off-peak hours (11p.m. to 7a.m.)

The MCP in Perspective

On March 30, 1998, the PX began accepting bids from generators in California and out-of-state on an hourly basis to meet electricity demand primarily that of the customers of IOUs.[3] The last bid accepted for a particular hour sets the price that the PX pays all generators for electricity provided in that hour. That price is the MCP.[4] The MCP, along with ancillary service payments, must-run costs and grid management costs, determines the energy (variable) cost component of the electricity bills for most Californians.[5] Some customers, instead of purchasing their electricity from the PX, obtain their electricity directly from generators through individual contracts, alternatively referred to as direct access or bilateral contracts. These contracts are in some cases indexed to the MCP of the PX. The MCP, therefore, can affect the price that direct access customers pay for electricity.

On December 10, 1997, staff produced its first forecast of annual MCPs, based on the combined results of computer simulations using the UPLAN[6] model and exogenous calculations based on the cost of a new market entrant. As a check on the reasonableness of the forecast, staff also reviewed price results from General Electric's MAPS Model, the Environmental Defense Fund's Elfin Model, and the Altos NARE model.

This 1998 MCP Forecast uses the same approach of relying on results from the UPLAN Model and the cost of a new entrant to put an upper limit on the MCP. From 1998 to 2001 the forecasted annual MCP reflects the results of the UPLAN model combined with known historical data. After 2001, the annual MCP is set equal to the annual revenue requirement of a new entrant. This is one year earlier that the 1997 forecast. We've taken this approach based on the belief that as the MCP rises in response to increased load, it will ultimately reach a level that sends a favorable price signal to attract new entrants. In this forecast we also provide hourly MCPs by month and year using the forecasted monthly MCPs from UPLAN and a scaling routine based on historical hourly PX prices and demand. (See Appendix D for additional detail.)

There are shortcomings to using the annual revenue requirement of a new entrant to set the post-2001 MCPs. For instance, a new entrant will not operate in all the hours of the year and therefore will not be paid the annual average MCP. The new entrant could actually operate predominantly in the higher MCP hours and therefore be more profitable. Generators also have other revenue-making opportunities in the ancillary services markets and through reliability must run contracts with the ISO. They need not rely solely on the PX energy market for all their revenue. These factors suggest that the MCP may be too high. There are other factors at work, however, that would indicate that using the estimate of the annual revenue requirement of a new entrant to set the MCP is too conservative. The operating hours of the new entrant will be limited by maintenance requirements, forced outages and minimum load conditions. Also, during low-load, off-peak hours the new entrant may have to

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[3] California's municipal utilities are not required to participate in the PX although some may be using the PX for spot purchases.

[4] The seller's MCP is equal to the buyer's MCP as the generators are required to be responsible for transmission losses.

[5] The energy rate for consumers will be the seller's/buyer's MCP adjusted for distribution losses.

[6] UPLAN is an electric utility simulation model, owned by LCG Consulting of Los Altos, California, that combines an emulation of the generation and transmission of electricity for the Western Systems Coordinating Council (WSCC) region with the bidding protocols of the California Power Exchange.

operate at a loss, if it is a slow-start unit -- one that takes several hours to come on-line -- in order to be available during the high-load peak hours. Taking all these factors into consideration, staff believes that its MCP forecast for the years after 2001 is reasonably close to the level necessary to attract new entrants.

If the annual average MCP falls short of this -- as it may -- then the viability of the market is questionable. The ISO would have to take remedial action to attract new entrants. This could take the form of a capacity payment or other forms of remuneration such as must-run contracts. To the extent that a generator's costs are recovered outside of the PX energy market, the generator can afford to bid its energy into the market at lower levels -- perhaps approaching incremental cost. While payments outside of the energy market may be a more cost-effective way to ensure the reliability of the system, they are counterproductive to the goal of sending the correct market signal needed to attract new entrants.

Forecast vs. Actual 1998

Tables 3A-C below compare the actual unweighted PX price to the previous 1997 and current 1998 Energy Commission forecasts. One obvious conclusion drawn from this comparison is that the cost-based bidding used in our modeling, which assumes average market demand/supply conditions, cannot mimic actual market bids, which reflect the unique conditions of the moment. During the first few months of the market, the MCP underwent fluctuations in bidding levels as the participants attempted to understand the market. This normal learning process was complicated, however, first by record high hydro conditions that drove prices dramatically downward - and later by record heat storm and high demand conditions that drove prices skyward in both the PX energy and the ISO ancillary services markets.

For the month of April, staff's interim and revised forecasts and the actual PX energy price were comparable because higher than expected gas prices offset the effect of higher than average hydro availability. But by May and June, gas prices returned to expected levels, and the abundance of hydro generation, combined with the large amount of must-take and must-run generation, resulted in MCPs being at zero for approximately129 hours for these two months (9 percent of the time). The MCPs on average for these months were significantly below the incremental operating cost of most units.

Staff estimated that this year's high hydro conditions led to May and June MCPs that were less than half of what could be expected under average hydro conditions. In July, August, and September higher than expected prices occurred, driven primarily by record high temperatures. The August PX average price was $10 per MWh higher than that expected for an average year.

While we expected this first year to be volatile, as participants honed their bidding skills, the market to date has shown both the extreme upside and downside risk in terms of expected revenue. Staff's forecasts -- this and the previous forecast -- do not attempt to capture these perturbations. Our forecasts reflect normalized (average) conditions, in terms of temperature, expected load, and hydro availability. Using these normalized market conditions leads to an average expected MCP suitable for analysis that involves a time horizon beyond one year.

Table 3A
Monthly Average
(Nominal $/MWh)

1998	Nov. 1998 Forecast	Actual PX Price	Dec. 1997 Forecast
Apr	21.0	22.6	22.1
May	20.0	11.9	24.1
June	19.2	11.9	23.9
July	27.3	32.6	30.5
Aug	30.1	40.0	29.6
Sept	30.5	33.7	28.4
Oct	24.8	26.7	27.2
Nov	26.0	25.8	28.1
Dec	29.0	NA	31.2
Annual	25.3	NA	27.3

Table 3B
Monthly On-Peak Average
(Nominal $/MWh)

1998	Nov. 1998 Forecast	Actual PX Price	Dec. 1997 Forecast
Apr	24.1	25.9	24.3
May	26.6	15.6	27.1
June	26.6	16.7	28.4
July	33.9	40.3	34.3
Aug	37.4	49.6	33.3
Sept	35.9	39.6	31.5
Oct	27.8	29.8	29.1
Nov	28.9	28.5	30.3
Dec	32.3	NA	34.1
Annual	30.4	NA	30.3

Table 3C
Monthly Off-Peak Average
(Nominal $/MWh)

1998	Nov. 1998 Forecast	Actual PX Price	Dec. 1997 Forecast
Apr	15.9	17.1	18.5
May	9.0	5.8	18.9
June	6.7	4.0	16.4
July	16.3	19.7	24.3
Aug	17.9	23.8	23.5
Sept	21.6	23.8	23.2
Oct	19.7	21.5	24.0
Nov	21.1	21.3	24.5
Dec	23.6	NA	26.4
Annual	16.9	NA	22.0

While the forecasted and actual prices shown in Tables 3A-C are not identical, the pattern of monthly variation in prices is comparable. We believe that our forecasted prices reasonably approximate the trend in PX prices. Actual PX prices reflect the deviation from the expected trend due to market imperfections and volatility in key market factors, such as resource availability, temperature, and demand.

The one significant reservation that we have about our forecast from the UPLAN model is that the hourly prices were relatively flat during the peak hours, whereas the hourly trend in actual PX MCPs shows a close correlation with demand. We believe that the flatness in hourly prices from UPLAN can be largely attributed to two factors. One is that our bidding of generation in the UPLAN model does not vary on an hourly basis. This modeling approach will not capture the opportunity bidding taking place in the PX market in the peak hour periods. Likewise, it will be unable to accurately mimic the bidding behavior in off-peak periods in some months where generators are clearly bidding less than their incremental cost in order to be available during the peak periods. (We provide a more detailed explanation of how we bid generation under the Model Assumptions portion of Section IV: Market Uncertainty and Assumptions).

The other factor that we believe is contributing to flat hourly prices from the UPLAN model is its dispatch routine that uses the combined loads of all the regions in the WSCC to perform an optimal dispatch for the entire WSCC. Because peak load conditions occur during different hours and months within the various regions of the WSCC, their combined loads will have a relatively flat load shape when compared to the load shape for each individual region.

Another concern is that the model is using historical load shapes based on the loads of the previously regulated utilities. The utilities' historical load shapes include the demands of industrial customers that are, or will most likely be, served through direct access contracts. These industrial customers have a relatively flat demand profile. To the extent that this industrial demand is met outside of the PX market means that the remaining customer load served through the PX will have a lower load factor, and that the load shape of demand in the PX market should have a more pronounced peak.

In order to provide a reasonable forecast of hourly peak and off-peak prices from the PX, we created a scaling routine using actual PX MCPs and demand data that is then applied to the monthly MCP forecast from UPLAN. The methodology for creating this scaling routine is described in Appendix D. The Energy Commission forecast shown in Figures C1 through C4 of Appendix C is the product of the scaling routine.

Because of the interest in minimizing market risk we provide in Appendix E a graphical comparison of the historical PX prices for the months of April through September to the Palo Verde and the California Oregon Border (COB) Hub Prices. These Hub prices are for firm delivered electricity and are based on survey data which reports the high and low price for the peak and off-peak period for each day of the month. We have averaged this data into an average week for each month. These graphs provide some indication of the extent to which suppliers and consumers could have lowered their exposure to market volatility through futures contracts at these locations. In general, the Hub prices tended to be higher than the PX price during off-peak hours and lower during peak hours. Because of the volatility in the PX market, we would expect that our forecasted hourly values would more closely approximate these Hub prices.

Comparing the two Hub prices reveals, as expected, that the COB price is significantly lower than the Palo Verde price during the spring runoff months because of the substantial amount of hydro in the Northwest. During the summer months the Palo Verde Hub price is still higher than the COB price, but only slightly so. In the winter, when the Pacific Northwest has its peak season, and hydro availability is limited, the COB price should be higher than the Palo Verde.

IV. MARKET UNCERTAINTY AND ASSUMPTIONS

This section discusses some of the factors contributing to future market uncertainty and provides additional information on the inputs and assumptions used in the UPLAN model.

Market Uncertainty

There are numerous factors that make modeling of the competitive market a challenging exercise. The interaction of these factors and their influence on the MCP is not easily understood. The current competitive market actually consists of several markets. These include the PX's day-ahead and hour-ahead markets, and the ISO's real-time balancing and ancillary services markets. The terms and conditions of these markets (especially the presence of price caps) have had a strong influence on how generators bid and into which markets they bid.

Further complicating the picture is the presence of the reliability must-run (RMR) contracts. The terms of these contracts and how often the ISO calls upon them also directly affect how and when participants will bid into the PX energy market. The extent to which the ISO continues to rely on and utilize reliability must-run contracts perhaps has the largest influence on how competitive the market will ultimately be. The longer these agreements stay in place, the less transparency there is in the market and the more ambiguous the price signals that it sends.

RMR contracts are necessary to satisfy local reliability concerns, such as providing voltage support. There are approximately 16,200 MWs of generation under RMR contracts.[7] This represents about 27 percent of statewide existing and committed capacity. These units are providing a service, different from energy, at specific locations where competition is believed to be absent. However, the reliance of the ISO on these contracts directly affects the competitiveness of the market. It may be in the unit's best interest not to bid into the energy and ancillary services markets when there is a substantial likelihood of being called upon to provide electricity under an RMR contract at a higher price. There are also conditions within some RMR contracts that prohibit a generator from bidding into the market.

The pace and extent of deregulation of electric utilities outside of California is also uncertain and will directly influence the MCP. The early years of this forecast presume that out-of-state generators remain under traditional regulation. This gives them a competitive advantage since they are able to bid their incremental cost of generation, which recovers just their variable costs (fuel + variable O&M), while their fixed capital costs are recovered in their regulated rates. This has the effect of placing a ceiling on the bids of generators that have to recover their fixed capital costs from the PX energy market. The impact of this assumption is especially strong during the low load spring and autumn months when the amount of surplus energy outside California is greatest.

Another factor that adds uncertainty to forecasting the MCP, more so in the long run, is the role of demand-side bidding. Demand in the current PX market is still relatively inelastic. In order to increase demand elasticity in the PX market, there would have to be a significant penetration of time-of-use meters and other technologies, such as direct end-use load control devices programmed to

[7] Reliability Must-Run Unit list for 1998 is available at the ISO website: www.caiso.com

respond to price signals. However, we do not expect demand-side bidding to have a significant moderating influence on PX prices in the 1999 to 2001 time frame.

On the supply side, the two most significant unknowns are the future role of divested units and the commercial viability of existing nuclear units. Many of the divested facilities were sold at a price considerably more than their book value. Without substantial modification and improvements to these units' efficiency, it will be difficult for them to recover their fixed capital and operation and maintenance (O&M) costs once new, more efficient generators enter the market. Improvements in new generation technology efficiency will also affect future MCPs.

As for the nuclear units, even under the most optimistic forecasts of MCP, it will be difficult for them to be profitable based on revenue from the PX alone. Should these units be unable to operate profitably after the competition transition charge (CTC) recovery period ends on March 31, 2002, they would most likely be shut down. However, if the ISO determines that supply is inadequate to meet demand without these units, or that they play a critical role in maintaining the stability of the transmission network, it may choose to execute supply sufficiency contracts and/or reliability must-run contracts to keep them operating.

Model Assumptions

All forecasts are driven by the assumptions therein. In this new competitive market, the assumptions used in the forecasting of MCPs define the risk exposure of market participants. The modeling assumptions used in this forecast describe the underlying market conditions in terms of resource availability, market demand, and production cost. Actual market conditions may vary little, or widely, from the assumption used in this forecast. If they differ significantly from what is assumed in this forecast, then the forecast can help quantify the magnitude of risk that the market participant faces.

The assumed gas prices for in-state gas-fired units are attached as Appendix A and represent the Energy Commission's most recent forecast, as presented in the *1997 Fuels Report* (FR 97). FR 97 was prepared by the Commission's Fuels Office and approved by the full Commission at their March 18, 1998 Business Meeting. The associated general escalation forecast that was used is also in Appendix A. Questions about the gas price forecast should be addressed to Bill Wood (Phone numbers, FAX numbers and EMAIL addresses are available in Section V). The FR 97 gas prices are based on pre-divestiture ownership -- as are most of the assumptions in this MCP. The gas prices are significantly lower than those of FR 95 but essentially the same as those used in the December 10, 1997 Forecast. Both of these MCP forecasts are significantly lower than that of the October 1996 LCG Report[8] which had estimated that the 1998 MCP would be 29 - 30 $/MWh in Northern and Southern California, respectively. The lower forecast MCPs are traceable -- at least in part -- to the lower gas prices.[9]

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[8] Modeling the Competitive Energy Market in California: Analysis of Restructuring, dated October 1996. Prepared by Rajat K. Deb, Richard S. Albert and Lie-Long Hsue of LCG Consulting, available at the Energy Commission's Internet Site: http://www.energy.ca.gov/energy.

[9] Also contributing to the decrease in MCP from the October 1996 report is the change from 3-Part bidding to 1-Part bidding.

UPLAN loads, supply and transmission representation have been revised since the December 10, 1997 MCP Forecast. Both forecasts assumed loads for California based on the Energy Commission's adopted *ER 96 Load Forecast*.[10] Questions about the *ER 96 Load Forecast* should be directed to Mike Jaske. The previous forecast used the 1996 WSCC load forecast for regions outside of California. The new forecast uses the revised load forecast from the 1997 WSCC 10-Year Plan.[11] The model also uses historical hourly load profiles developed from EEI load data filed by utilities in the WSCC with the Federal Energy Regulatory Commission (FERC). The historical hourly load data is used to create a load shape for a typical week (168 hours) to represent each month for 15 different load zones. The load for each zone is then allocated to nodes in the transmission network.

The previous MCP forecast relied on a more aggregated level of information in terms of how resources and transmission were represented in the WSCC. This new forecast uses a greater level of detail in the representation of generation, demand and transmission in the WSCC. The representation of the WSCC in the UPLAN model was greatly expanded from the previous forecast. The number of power plants modeled was increased from 314 to 561. The number of load nodes was expanded from 15 to 260, and the number of transmission lines increased from 210 to 1225 lines.

The supply data for the WSCC region outside of California was updated using the North American Electric Reliability Council (NERC) 1997 Electricity Supply & Demand database. The representation of hydro in the Northwest was revised using updated information obtained from the Northwest Power Planning Council. The resource data was significantly modified to increase the amount of detail on the generating units. Most out-of-state thermal plants and in-state municipal-owned thermal units in the previous forecast were represented as either one or two capacity blocks. In this new forecast all gas- and coal-fired units, with the exception of combustion turbines, are represented as having three blocks. The non-economic constraints (including ramp-rates, warm-up costs & times -- both for cold-starts and warm-starts) for California units that had Master Must-Run Agreements were updated using the information contained in the utility October 1997 Master Must-Run Agreement filings with the FERC.

Transmission in the UPLAN model can be emulated using as a contract path algorithm (transport), or a more detailed D.C. or A.C. power flow simulation. The A.C. simulation takes the most computer run time. The previous forecast used the A.C. power flow method; however, because of the increase in the number of lines modeled in the new forecast, it was necessary to use the model's D.C. power flow emulation to keep the simulation run times reasonable. Questions regarding the development of the equivalent transmission network used in the model can be directed to Mark Hesters or Ean O'Neill.

This MCP Forecast - as with the earlier December 1997 Forecast - assumes a normalized year. The weather pattern and hydro availability and demand patterns are assumed to be average.

The modeling also presumes the existence of a less complex, more mature/competitive market. In the model, all available IOU generation and load is bid into the PX energy market. In reality not all generation and IOU load is bid into the PX market. Direct access load and generation is not part of the PX market. Generators and demand can be bid into the ISO imbalance market. Generators also

[10] *California Energy Commission Electricity Report,* Appendix A, dated November 1997, P300-97-001.
[11] 10-Year Coordinated Plan Summary 1997-2006, dated May 1997 (www.wscc.com).

have other revenue making opportunities in the ISO's ancillary services market, as well as through RMR contracts. As mentioned earlier, the presence of price caps in some of these markets influences where generation and load is bid, and the terms of the RMR contracts influence when the generator is likely to bid into the PX energy market.

Maximum participation by out-of-state generators is also assumed in the model. These generators are bidding into the market to extent that they have unused capacity and transmission is available.

We also assume that these out-of-state generators are bidding their incremental cost in the PX market for the reason stated in the Market Uncertainty portion of this section. This assumption has the effect of limiting what generators in-state can bid during certain months.

In terms of how in-state generators are assumed to bid into the market, the PX requires that market participants bid each unit (or group of units) monotonically; that is, the price must increase with each subsequent capacity block offered. Given these rules, bidding a generator into the market based on its cost is problematic because a generator's cost decreases as its generation increases. To model this paradox accurately would involve iterative runs of the model. From these runs, we would determine the exact capacity level of the unit for each hour of operation in order to construct a bidding curve that would allow for full cost recovery. The alternative approach, used for this forecast, involves adjusting bids based on knowledge of a unit's heat rate and the prevailing market conditions in terms of available supply and demand, while allowing for bids to be lower in the off-peak hours, but higher during on-peak hours. As discussed below, the use of UPLAN's bidding heat rate option allows for this approach.

The UPLAN model results used in the early years of this forecast assume a bidding strategy based on three different runs based on different seasons of the year and market opportunities. Each run assumes a different bidding strategy for the gas-fired steam turbine and combined-cycle generating units in the State.

Staff’s UPLAN modeling assumes that in-state units owned by IOUs or others who are also dependent on the energy market for their total revenue cannot be profitable bidding only their incremental costs. Bidding solely the plant's incremental costs -- reflecting incremental heat rates (plus variable O&M) -- would be equivalent to the marginal cost dispatch procedure of traditional production cost modeling, and would result in a MCP that would not allow the plant to survive the market. In support of this position, staff demonstrated in previous documents that the MCP should on average be about 30 percent higher than marginal cost.[12]

For in-state gas-fired steam turbine and combined-cycle units, staff's forecast relies on a default bidding option within the model that allows the user to specify bids that are based on the unit's heat rate. Each of these units is modeled with three capacity blocks. Each capacity block has an associated heat rate. While the UPLAN model does allow the user to specify an hourly bidding schedule for every hour of the year for each of the unit's capacity blocks, specifying hourly bids would have been

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[12] See the December 10, 1997 *Interim Staff Market Clearing Price Forecast for the California Energy Market: Forecast Methodology and Analytical Issues* and the April 7, 1998 *The Use of Heat Rates in Production Cost Modeling and Market Modeling*. Both are available at the Energy Commission’s WEB site; http://www.energy.ca.gov/papers.

extremely time consuming and involved an elaborate guessing exercise on the part of the modeler. As described below, using the default bidding heat rate option allowed for a reasonable approximation of bidding behavior.

The MCP forecast from UPLAN is the combination of three separate runs using the default bidding heat rate mechanism. One run assumes that during the winter months of December and January a generator's peak-hour bids are based on the unit's fuel cost times the average heat rate at the unit's second block plus variable O&M and start-up costs. Off-peak hour bids use the average best heat rate times the fuel cost. Another run for the months of July, August, and September assumes generators bid the cost of operating at the first block level (their highest operating cost) during the peak hours and the unit's average best heat rate during off-peak hours. For all other months, the model is run with generators bidding at their incremental operating cost. Table 4 summarizes the bidding scheme used in the UPLAN modeling.

Table 4
Bidding Heat Rates Used in the UPLAN Model

	Off-peak (11pm-7am)	On-Peak (8am-10pm)
January	Best Heat Rate	Block 2 Heat Rate
February	Incremental Heat Rate	Incremental Heat Rate
March	Incremental Heat Rate	Incremental Heat Rate
April	Incremental Heat Rate	Incremental Heat Rate
May	Incremental Heat Rate	Incremental Heat Rate
June	Incremental Heat Rate	Incremental Heat Rate
July	Best Heat Rate	Block 1 Heat Rate
August	Best Heat Rate	Block 1 Heat Rate
September	Best Heat Rate	Block 1 Heat Rate
October	Incremental Heat Rate	Incremental Heat Rate
November	Incremental Heat Rate	Incremental Heat Rate
December	Best Heat Rate	Block 2 Heat Rate

Bid($/MWh) = Heat Rate (Btu/kWh) * Fuel Cost ($/MMBtu)/1000 + VOM ($/MWh)
+ Start-up ($)/Energy Produced (MWh)

We clearly recognize that during some months many bidders will, as the results from actual market have shown, bid less than their costs off-peak in order to remain on-line, and bid significantly higher than cost during on-peak periods when demand is high and supply limited. This forecast, however, assumes no significant market power, consistent with FERC and California Public Utilities Commission (CPUC) guidelines, but at the same time recognizes that some participants may very well be able to control the MCP during some limited times of the year. This behavior may be akin to market power but is not necessarily an abuse, as this limited control of the MCP might very well be necessary to compensate for losses during other periods, and may be necessary for economic survival.

There will be periods during the year where bids momentarily rise significantly above a generator's variable costs. These periods of "opportunity bidding" will occur when demand is high, typically a hot summer day or cold winter day, and starts to exceed available resources. Maintenance and forced-outages of generators or transmission lines will also contribute to shortages in supply. Because the IOUs have divested most of their generation, it will be more difficult to coordinate outages among plant owners. We expect that occurrences of tight supply due to outages may occur more frequently despite the ISO's efforts to coordinate resource availability.

As loads increase and reserve margins decrease, periods of "opportunity bidding" will be more frequent, until new resources begin to enter the market. In the post 2001 period, when reserve margins diminish, the MCP will start to rise more sharply. By 2002 the MCP will be sufficient to attract new entrants at a cost of about 26.6 $/MWh (1998$). We base this assumption on the need for the market to send an appropriate price signal to attract a new entrant.

Our estimated cost of a new entrant reflects the perception by entrepreneurs of what market price signal is necessary to encourage entry. Staff believes that new developers may be over-estimating the probable capacity factors and therefore the average heat rate and underestimating the capital and fixed O&M costs. The economics of new entrants is covered in more detail in Appendix F.

Staff expects that between 1998 and 2000, existing reserve margins are sufficient to meet additional load. Between then and 2002, when the new entrants come on line, staff assumes that additional load will be served by out-of-state generators that will see the California PX market as an economic opportunity for off-system sales. From 2002 onward it is assumed that the MCP will remain essentially at the cost of new entrants, as each time the MCP starts to rise above this level, a new entrant will come into the market, resetting the MCP at approximately its former level.

This MCP forecast assumes that all IOU Combustion Turbines (CTs) will have type C must-run contracts, and will not be allowed to set the MCP. The forecast also assumes that the slow-start units shown in Table 5 will have type A or B contracts and will be allowed to set the MCP when not dedicated to the ISO for reliability dispatch.

In all of staff's simulations with the UPLAN model, some generators are consistently unable to recover all of their variable and fixed O&M costs. Most of these same generators have been identified as necessary for the reliability of the system and will most likely receive sufficient remuneration from must-run contracts with the ISO. The remaining units that do not have must-run contracts and do not appear viable without them are the Highgrove and Long Beach plants.

TABLE 5: TYPE A & B MUST-RUN CONTRACTS

PG&E	SCE	SDG&E
Contra Costa 6 & 7	Alamitos 1 - 6	Encina 1 - 5
Humboldt 1 & 2	El Segundo 1 - 4	South Bay 1 - 4
Hunters Point 2 - 4	Etiwanda 1 - 4	
Moss Landing 6 & 7	Huntington Beach 1 & 2	
Pittsburg 1 - 7	Mandalay 1& 2	
Potrero 3	Redondo 5 - 8	

V. ENERGY COMMISSION CONTACTS

The following is a list of the Energy Commission personnel who were involved directly or indirectly in the MCP Forecast, along with their phone numbers, FAX numbers and EMAIL addresses. This list is intended to facilitate your information requests related to this study. If you are in doubt as to whom to contact, you can contact the authors, who will direct you to the appropriate source. Copies of this report, as well as EXCEL spreadsheets, which contain all of the data and graphs, contained in the report, are available from the Energy Commission's Web Site:

http://www.energy.ca.gov/papers.

TABLE 6: ENERGY COMMISSION CONTACTS

SUBJECT	PERSONNEL	PHONE	FAX	EMAIL
Authors	Joel B. Klein	(916) 654-4822	(916) 654-4559	jklein@energy.state.ca.us
	Richard Grix	(916) 654-4859	(916) 654-4559	rgrix@energy.state.ca.us
UPLAN Modeler	Richard Grix	(916) 654-4859	(916) 654-4559	rgrix@energy.state.ca.us
New Entrant Costs	Richard Grix	(916) 654-4859	(916) 654-4559	rgrix@energy.state.ca.us
Transmission	Mark Hesters	(916) 654-5049	(916) 654-4421	mhesters@energy.state.ca.us
	Ean O'Neill	(916) 657-0535	(916) 654-4421	eoneill@energy.state.ca.us
Demand Forecast	Mike Jaske	(916) 654-4777	(916) 654-4901	mjaske@energy.state.ca.us
Fuel Price Forecast	Bill Wood	(916) 654-4882	(916) 654-4753	bwood@energy.state.ca.us
	Jairam Gopal	(916) 654-4880	(916) 654-4753	jgopal@energy.state.ca.us

Table 7 provides a summary of the model vendors whose models were used in either the present MCP Forecast or the earlier December 10, 1997 MCP Forecast.

TABLE 7: MODEL VENDOR CONTACTS

MODEL	PERSONNEL	PHONE	FAX	EMAIL
UPLAN	Dr. Rajat K. Deb	(415) 962-9670	(415) 962-9615	deb@energyonline.com
MAPS	Rana Mukerji	(518) 385-9336	(415) 385-3165	mukerja@psedmail.sch.ge.com
	Gary Jordon	(518) 385-2640	(415) 385-3165	jordon@psedmail.sch.ge.com
ELFIN	Dan Kirshner	(510) 658-8008	(510) 658-0630	elfin@edf.org
NARE	Dale Nesbit	(408) 275-0789	(408) 275-0799	
	Richard White	(408) 275-0789	(408) 275-0799	

APPENDIX A
FINAL FR 97 GAS PRICE FORECAST

Table A-1 summarizes the in-state natural gas prices used in this 1998 Staff MCP Forecast, in both nominal (current) and real 1998 dollars. The columns marked “Disp” give the dispatch (variable) cost of component. The columns titled “Total” give the total price of gas (dispatch plus fixed). Figures A-1 through A-4 provide this same data in graphical format. Figures A-1 and A-2 present the nominal values and A-3 and A-4 present the real 1998-dollar values.

The irregular transition from 1998 to 2000 represents the price drop that is expected when the extensive reserves of the Gulf of Mexico enter the market, once the transportation facilities are complete. The effect of this in real dollars is that prices do not rise to their 1998 values until about 2112.

TABLE A-1

FINAL FR 97 GAS PRICE FORECAST (MARCH 18, 1998)

Nominal $/MMBtu

	PG&E		SCE		Cool Water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total
1998	2.31	2.51	2.43	2.61	2.24	2.34	2.34	2.91
1999	2.04	2.24	2.08	2.27	1.90	2.00	2.04	2.56
2000	1.98	2.19	1.97	2.17	1.98	2.08	2.07	2.61
2001	2.07	2.28	2.09	2.29	2.08	2.18	2.18	2.73
2002	2.17	2.38	2.20	2.40	2.17	2.27	2.29	2.85
2003	2.28	2.50	2.34	2.55	2.28	2.38	2.42	2.98
2004	2.40	2.62	2.48	2.69	2.41	2.51	2.56	3.13
2005	2.53	2.75	2.63	2.85	2.55	2.65	2.70	3.28
2006	2.66	2.89	2.78	3.00	2.70	2.80	2.84	3.43
2007	2.80	3.03	2.95	3.17	2.85	2.95	3.01	3.61
2008	2.94	3.18	3.15	3.38	3.01	3.11	3.21	3.81
2009	3.09	3.34	3.33	3.57	3.18	3.28	3.38	3.99
2010	3.25	3.51	3.45	3.69	3.34	3.44	3.51	4.14
2011	3.44	3.70	3.65	3.90	3.52	3.62	3.72	4.36
2012	3.64	3.91	3.87	4.12	3.70	3.80	3.94	4.58
2013	3.86	4.13	4.09	4.35	3.89	3.99	4.16	4.82
2014	4.08	4.36	4.32	4.59	4.09	4.19	4.39	5.06
2015	4.30	4.59	4.55	4.83	4.30	4.40	4.63	5.31
2016	4.54	4.83	4.81	5.10	4.51	4.61	4.89	5.59
2017	4.79	5.09	5.07	5.37	4.74	4.84	5.15	5.86

Apr 16, 1997	
Deflators	
1998	1.00
1999	1.02
2000	1.05
2001	1.08
2002	1.11
2003	1.15
2004	1.18
2005	1.22
2006	1.27
2007	1.31
2008	1.36
2009	1.41
2010	1.46
2011	1.51
2012	1.56
2013	1.62
2014	1.68
2015	1.74
2016	1.80
2017	1.87

1998 $/MMBtu

	PG&E		SCE		Cool Water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total
1998	2.31	2.51	2.43	2.61	2.24	2.34	2.34	2.91
1999	1.99	2.19	2.03	2.21	1.85	1.95	1.99	2.49
2000	1.88	2.08	1.88	2.06	1.88	1.98	1.96	2.48
2001	1.91	2.11	1.93	2.11	1.92	2.01	2.01	2.52
2002	1.95	2.14	1.98	2.16	1.95	2.04	2.05	2.56
2003	1.99	2.18	2.04	2.22	1.98	2.07	2.11	2.59
2004	2.03	2.21	2.10	2.28	2.04	2.12	2.16	2.64
2005	2.06	2.25	2.15	2.32	2.09	2.17	2.20	2.68
2006	2.10	2.28	2.19	2.36	2.13	2.21	2.25	2.71
2007	2.13	2.31	2.25	2.42	2.17	2.25	2.29	2.75
2008	2.16	2.34	2.32	2.49	2.22	2.29	2.36	2.81
2009	2.19	2.37	2.36	2.53	2.26	2.33	2.40	2.84
2010	2.23	2.41	2.37	2.53	2.29	2.36	2.41	2.84
2011	2.28	2.45	2.42	2.59	2.33	2.40	2.47	2.89
2012	2.33	2.50	2.47	2.64	2.37	2.43	2.52	2.93
2013	2.38	2.55	2.53	2.69	2.40	2.47	2.57	2.98
2014	2.43	2.60	2.58	2.74	2.44	2.50	2.62	3.02
2015	2.48	2.64	2.62	2.78	2.47	2.53	2.67	3.06
2016	2.52	2.69	2.67	2.83	2.51	2.56	2.72	3.10
2017	2.57	2.73	2.72	2.88	2.54	2.60	2.76	3.14

FR 97 Compared to FR 95

Table A-2 compares the Final FR 97 Gas Price Forecast (3/18/98) used in this Forecast to the Interim FR 97 Gas Price Forecast (11/17/98) used in the December 10, 1997 Interim MCP Forecast. Although the dispatch gas prices have changed significantly, the total gas prices which are applicable to the MCP Forecasts have not changed significantly -- with the exception of the Coolwater facilities, which do not have a significant impact on the MCPs.

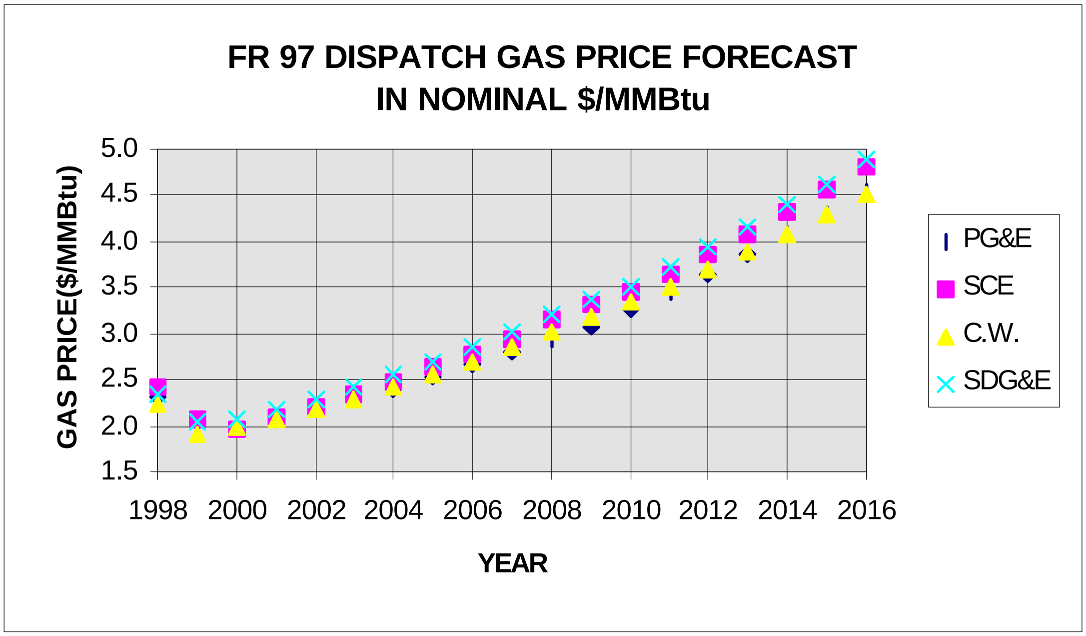


Figure A-1

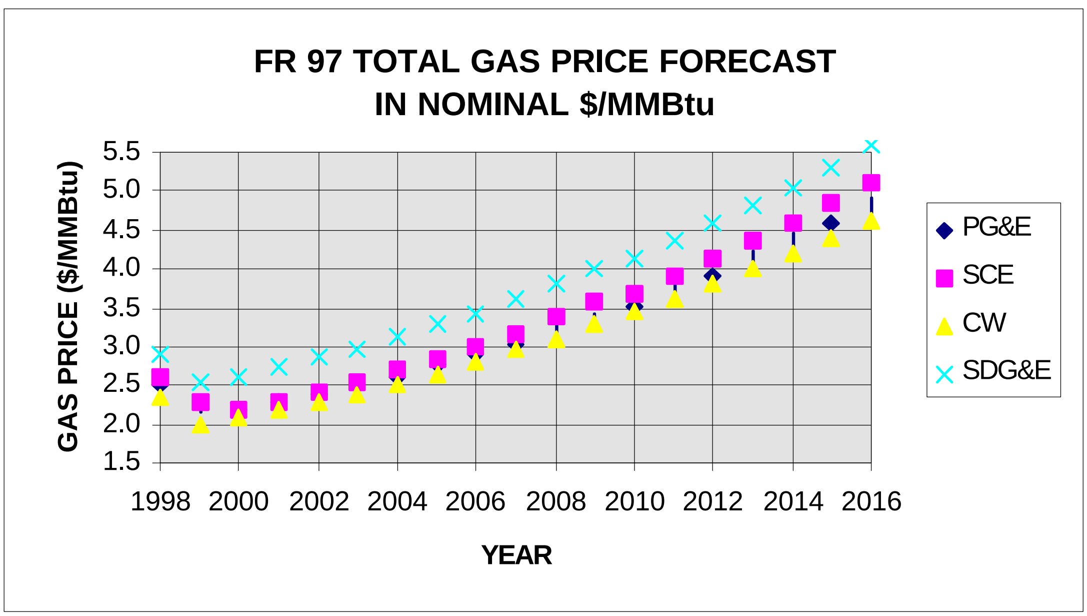


Figure A-2

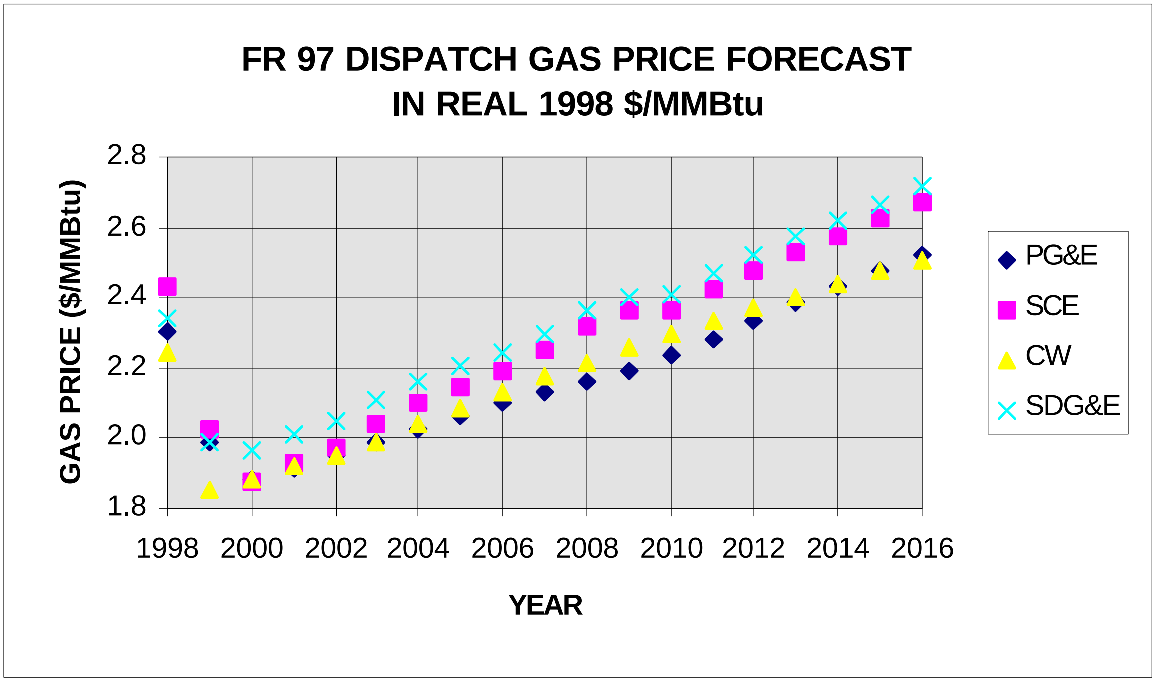


Figure A-3

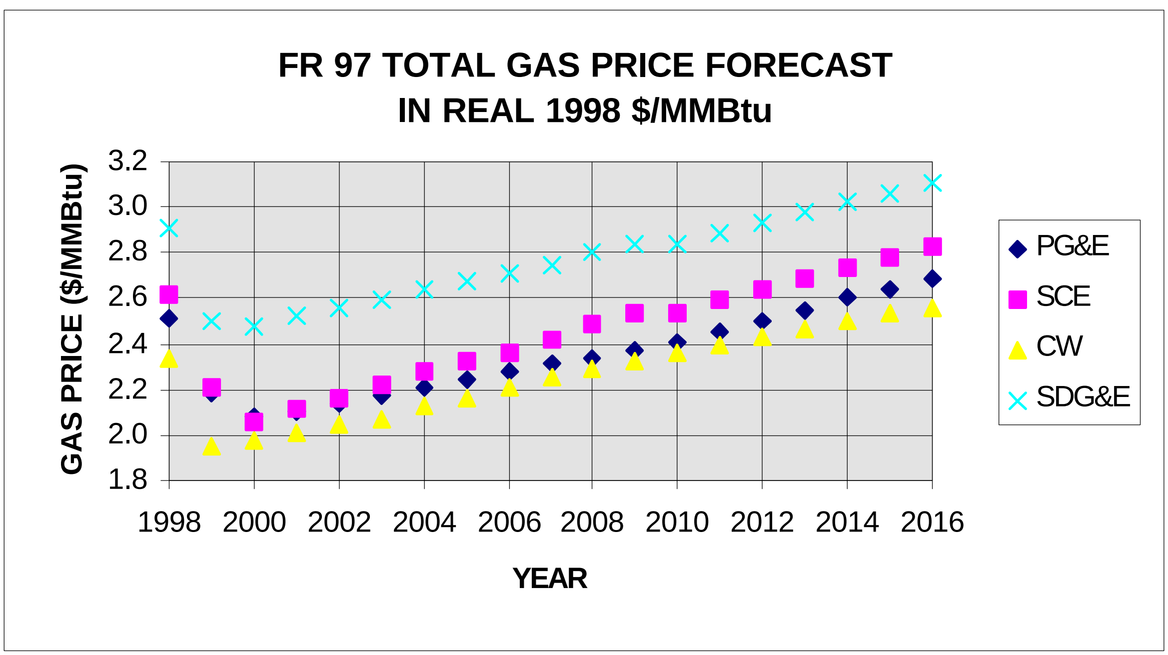


Figure A-4

TABLE A-2

COMPARISON OF FINAL FR 97 GAS FORECAST TO INTERIM FORECAST

FINAL FR 97 GAS PRICE FORECAST
(Used for the Revised MCP Forecast)
Nominal $/MMBtu

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total

1998	2.31	2.51	2.43	2.61	2.24	2.34	2.34	2.91
1999	2.04	2.24	2.08	2.27	1.90	2.00	2.04	2.56
2000	1.98	2.19	1.97	2.17	1.98	2.08	2.07	2.61
2001	2.07	2.28	2.09	2.29	2.08	2.18	2.18	2.73
2002	2.17	2.38	2.20	2.40	2.17	2.27	2.29	2.85
2003	2.28	2.50	2.34	2.55	2.28	2.38	2.42	2.98
2004	2.40	2.62	2.48	2.69	2.41	2.51	2.56	3.13
2005	2.53	2.75	2.63	2.85	2.55	2.65	2.70	3.28
2006	2.66	2.89	2.78	3.00	2.70	2.80	2.84	3.43
2007	2.80	3.03	2.95	3.17	2.85	2.95	3.01	3.61
2008	2.94	3.18	3.15	3.38	3.01	3.11	3.21	3.81
2009	3.09	3.34	3.33	3.57	3.18	3.28	3.38	3.99
2010	3.25	3.51	3.45	3.69	3.34	3.44	3.51	4.14
2011	3.44	3.70	3.65	3.90	3.52	3.62	3.72	4.36
2012	3.64	3.91	3.87	4.12	3.70	3.80	3.94	4.58
2013	3.86	4.13	4.09	4.35	3.89	3.99	4.16	4.82
2014	4.08	4.36	4.32	4.59	4.09	4.19	4.39	5.06
2015	4.30	4.59	4.55	4.83	4.30	4.40	4.63	5.31

INTERIM FR 97 GAS PRICE FORECAST
(December 10, 1997 MCP Forecast)
Nominal $/MMBtu

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total
1998	2.03	2.50	2.58	2.58	1.67	2.11	2.22	2.86
1999	1.79	2.27	2.27	2.27	1.70	2.15	1.96	2.51
2000	1.71	2.20	2.31	2.31	1.77	2.23	1.99	2.64
2001	1.78	2.29	2.31	2.31	1.84	2.32	2.07	2.80
2002	1.86	2.38	2.42	2.42	1.92	2.41	2.17	2.93
2003	1.94	2.48	2.55	2.55	2.00	2.50	2.27	2.91
2004	2.03	2.60	2.68	2.68	2.09	2.63	2.37	3.12
2005	2.12	2.72	2.80	2.80	2.19	2.75	2.49	3.19
2006	2.22	2.85	2.96	2.96	2.30	2.89	2.62	3.42
2007	2.33	2.98	3.12	3.12	2.41	3.02	2.75	3.57
2008	2.47	3.12	3.29	3.29	2.54	3.17	2.89	3.73
2009	2.60	3.27	3.47	3.47	2.66	3.32	3.04	3.86
2010	2.75	3.44	3.66	3.66	2.80	3.49	3.22	4.09
2011	2.90	3.62	3.86	3.86	2.95	3.66	3.40	4.33
2012	3.06	3.80	4.09	4.09	3.10	3.84	3.60	4.54
2013	3.21	4.00	4.34	4.34	3.26	4.02	3.80	4.81
2014	3.39	4.20	4.59	4.59	3.43	4.22	4.01	5.05
2015	3.57	4.41	4.84	4.84	3.60	4.42	4.22	5.30

FINAL FR97 GAS FORECAST COMPARED TO INTERIM)
(REVISED FR 97/INTERIM FR 97 X 100%)
Percent (%)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total
1998	13.7%	0.5%	-5.7%	1.4%	34.1%	11.0%	5.6%	1.8%
1999	14.0%	-1.1%	-8.5%	-0.2%	11.6%	-7.2%	4.0%	1.9%
2000	16.0%	-0.8%	-14.6%	-6.1%	12.2%	-6.7%	4.0%	-1.2%
2001	16.6%	-0.3%	-9.5%	-0.9%	12.8%	-6.1%	5.1%	-2.7%
2002	16.5%	0.1%	-9.0%	-0.6%	13.4%	-5.5%	5.6%	-2.8%
2003	17.7%	0.6%	-8.1%	0.1%	14.0%	-5.0%	6.7%	2.2%
2004	18.2%	0.8%	-7.4%	0.4%	15.7%	-4.3%	8.1%	0.2%
2005	19.0%	1.2%	-6.1%	1.6%	16.6%	-3.6%	8.5%	2.6%
2006	19.8%	1.4%	-6.2%	1.2%	17.5%	-3.0%	8.7%	0.3%
2007	19.8%	1.7%	-5.6%	1.5%	18.1%	-2.5%	9.3%	0.9%
2008	18.8%	1.8%	-4.2%	2.7%	18.7%	-2.0%	10.9%	2.1%
2009	18.8%	1.9%	-4.1%	2.9%	19.3%	-1.4%	11.1%	3.3%
2010	18.5%	1.9%	-5.9%	0.8%	19.2%	-1.3%	9.1%	1.1%
2011	18.6%	2.3%	-5.4%	1.1%	19.3%	-1.1%	9.4%	0.6%
2012	19.2%	2.8%	-5.4%	0.9%	19.2%	-1.0%	9.5%	1.0%
2013	20.0%	3.3%	-5.7%	0.3%	19.1%	-0.9%	9.6%	0.2%
2014	20.4%	3.8%	-6.0%	0.0%	19.1%	-0.7%	9.5%	0.1%
2015	20.6%	4.0%	-5.9%	-0.1%	19.2%	-0.6%	9.6%	0.4%

APPENDIX B
HOURLY MARKET CLEARING PRICES
FOR AN AVERAGE WEEKDAY AND WEEKEND DAY
(1998-2001)

Hourly prices for a typical week representing each month for the years 1998 through 2008 are available in an EXCEL spreadsheet format and can be downloaded from the Commission's website.

MARKET CLEARING PRICE
Year 1998
Hourly Prices

Average Weekday and Weekend Day

($s/MWh)

	January		February		March		April (actual)		May (actual)		June (actual)	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1							15.01	18.46	4.78	5.50	3.85	5.17
2							12.86	15.93	3.51	3.85	2.38	2.96
3							12.20	15.19	2.69	2.32	1.28	2.24
4							12.34	14.65	2.60	2.09	1.17	1.72
5							13.96	13.96	3.80	2.17	2.06	1.73
6							20.39	14.62	8.54	2.42	5.07	1.73
7							24.05	14.52	11.14	1.64	5.31	0.00
8							26.53	16.08	15.36	3.41	9.07	0.88
9							26.81	18.21	16.54	6.40	12.77	3.49
10							27.49	21.41	19.11	8.16	17.98	7.99
11							28.29	22.73	20.46	8.73	19.75	11.00
12							28.34	22.83	19.95	9.33	19.64	13.52
13							28.29	22.20	19.93	8.68	20.76	14.17
14							28.45	21.77	20.47	8.40	22.45	14.92
15							28.25	21.05	19.97	8.23	23.15	15.60
16							27.99	20.87	18.98	7.82	22.99	16.45
17							27.34	21.16	18.03	8.87	21.08	16.89
18							26.42	22.00	16.83	9.31	18.68	16.52
19							26.27	22.52	16.02	8.19	17.39	14.75
20							27.51	24.75	16.52	9.67	14.32	12.26
21							28.63	26.63	20.58	13.19	18.50	16.53
22							26.61	24.13	16.96	10.98	15.87	15.33
23							25.38	21.95	12.93	8.77	10.70	9.67
24							20.48	18.13	8.88	5.98	6.43	5.25

MARKET CLEARING PRICE
Year 1998
Hourly Prices

Average Weekday and Weekend Day
($s/MWh)

	July (actual)		August (actual)		September (actual)		October (actual)		November (actual)		December	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	21.51	21.13	24.45	24.29	23.84	24.60	22.67	22.89	20.68	21.61	22.54	21.31
2	19.21	19.39	23.76	23.24	23.08	23.83	20.18	19.29	19.49	19.71	21.72	20.31
3	17.01	16.95	22.24	21.71	21.90	22.73	18.44	16.18	17.59	18.03	21.06	19.24
4	15.69	15.28	21.53	20.36	21.39	21.46	17.90	14.35	18.32	16.90	21.35	19.05
5	16.60	14.33	22.26	20.39	22.37	20.53	20.31	14.72	21.06	17.41	22.89	19.52
6	19.51	10.37	24.68	17.64	24.45	20.91	24.40	15.36	25.74	17.69	26.48	21.14
7	20.72	9.20	25.90	17.31	26.01	21.37	28.81	17.99	27.37	17.86	29.87	23.56
8	25.85	12.09	28.83	19.77	27.22	22.12	31.56	21.09	29.14	20.77	31.63	25.29
9	27.25	18.07	30.46	23.90	28.87	24.10	31.46	23.13	29.91	24.24	32.87	27.35
10	29.99	22.94	32.73	27.24	31.04	25.71	31.90	25.01	29.57	23.67	33.45	28.19
11	32.19	24.65	43.49	29.17	37.67	27.34	32.14	26.23	29.61	24.36	33.78	28.77
12	36.74	28.85	48.91	29.99	41.05	28.83	31.36	25.77	29.50	25.26	33.52	28.74
13	45.53	31.67	56.88	31.97	46.60	30.02	31.37	25.42	29.33	23.91	33.28	28.39
14	53.14	34.72	71.53	35.29	51.75	32.03	32.01	25.24	29.36	24.66	33.08	27.83
15	60.87	40.41	91.09	37.83	58.18	35.32	31.36	24.50	28.88	24.28	32.68	27.40
16	63.77	43.67	96.44	41.79	59.70	37.08	30.55	24.58	28.38	24.17	32.35	27.40
17	63.04	46.34	95.25	41.89	58.29	37.83	30.55	25.41	29.02	25.86	33.54	29.70
18	54.87	43.94	73.01	39.28	50.60	33.62	29.96	26.56	32.52	30.53	38.00	32.84
19	47.80	37.57	54.45	33.86	45.07	30.78	32.29	28.67	31.65	30.63	36.95	32.83
20	39.37	30.04	44.63	33.44	41.98	30.42	32.37	29.95	30.14	29.48	34.60	32.00
21	40.59	34.16	44.97	33.38	41.32	30.88	31.80	29.03	29.24	28.30	33.20	30.81
22	32.69	31.31	34.37	30.12	31.45	28.12	30.12	27.08	27.06	26.29	30.94	29.05
23	28.93	29.02	29.24	28.55	27.37	27.42	26.95	24.70	26.24	23.48	28.59	25.95
24	25.69	23.93	26.86	25.24	25.72	25.27	23.90	21.89	21.90	20.73	25.62	23.27

MARKET CLEARING PRICE
Year 1999
Hourly Prices

Average Weekday and Weekend Day

($s/MWh)

	January		February		March		April		May		June	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	21.34	20.18	19.22	18.17	18.34	17.34	15.92	14.37	7.72	7.49	5.54	5.09
2	20.57	19.24	18.52	17.32	17.67	16.53	14.41	12.73	5.69	5.29	3.35	3.37
3	19.94	18.22	17.96	16.41	17.13	15.65	13.68	11.57	4.72	3.90	2.36	1.80
4	20.22	18.04	18.21	16.24	17.37	15.50	13.52	11.42	4.56	3.23	2.10	0.87
5	21.67	18.49	19.52	16.65	18.62	15.88	14.41	11.73	5.91	3.52	3.35	0.89
6	25.08	20.02	22.58	18.03	21.54	17.20	17.30	12.65	10.74	4.33	7.23	1.30
7	28.28	22.31	25.47	20.09	24.30	19.17	21.86	14.30	18.10	6.24	13.73	2.05
8	29.95	23.95	26.98	21.57	25.74	20.58	24.22	15.79	22.52	9.51	18.98	6.44
9	31.12	25.90	28.03	23.32	26.74	22.25	25.30	17.52	26.86	12.77	23.11	9.03
10	31.68	26.69	28.53	24.04	27.22	22.94	26.12	19.22	30.43	15.19	27.31	11.96
11	31.99	27.24	28.81	24.53	27.49	23.41	26.57	20.29	32.41	16.77	30.36	15.07
12	31.74	27.22	28.58	24.51	27.27	23.39	26.69	20.67	33.28	17.50	31.64	16.78
13	31.52	26.88	28.38	24.21	27.08	23.10	26.73	20.46	33.56	17.27	32.66	17.48
14	31.32	26.35	28.21	23.73	26.91	22.64	26.70	20.31	33.90	17.13	34.29	18.12
15	30.95	25.95	27.87	23.37	26.59	22.29	26.61	20.06	33.40	16.75	34.75	18.55
16	30.63	25.94	27.59	23.36	26.32	22.29	26.45	19.95	32.47	16.71	34.61	19.18
17	31.76	28.13	28.60	25.33	27.29	24.17	26.10	19.92	31.25	17.45	33.43	20.37
18	35.99	31.10	32.41	28.01	30.92	26.72	25.62	20.32	29.28	17.65	30.89	19.96
19	34.99	31.09	31.51	28.00	30.06	26.71	25.65	21.32	26.99	16.98	27.33	18.19
20	32.77	30.31	29.51	27.29	28.15	26.04	26.41	23.15	28.14	18.27	24.96	16.66
21	31.44	29.17	28.31	26.27	27.01	25.07	26.49	23.88	32.41	23.27	28.84	20.97
22	29.30	27.51	26.38	24.78	25.17	23.64	25.38	22.19	27.08	20.05	24.63	18.47
23	27.08	24.57	24.38	22.13	23.26	21.11	22.97	19.69	18.67	14.65	18.08	13.99
24	24.26	22.04	21.85	19.85	20.84	18.94	18.89	16.18	12.98	9.60	10.46	7.64

MARKET CLEARING PRICE
Year 1999
Hourly Prices

Average Weekday and Weekend Day

($s/MWh)

	July		August		September		October		November		December	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	16.19	15.20	21.07	20.40	21.61	21.26	18.11	17.37	18.42	17.41	20.73	19.60
2	14.06	12.32	19.80	18.15	20.80	20.02	16.29	15.13	17.75	16.60	19.98	18.69
3	12.43	10.00	18.61	16.01	20.08	18.62	15.29	13.37	17.20	15.72	19.37	17.70
4	11.91	8.66	17.98	14.58	19.75	17.71	15.34	12.95	17.44	15.56	19.64	17.52
5	12.83	8.78	18.66	14.27	20.55	17.77	17.16	13.36	18.70	15.95	21.05	17.96
6	15.48	10.05	20.79	15.32	22.01	18.90	20.56	15.27	21.63	17.27	24.36	19.45
7	18.75	11.62	22.33	17.38	23.41	19.87	24.01	17.65	24.40	19.25	27.47	21.67
8	20.34	14.11	23.28	18.80	24.87	20.71	25.05	19.43	25.84	20.66	29.10	23.27
9	21.81	16.43	24.54	20.82	26.95	21.85	25.88	21.07	26.85	22.34	30.23	25.16
10	24.74	18.60	27.19	22.02	29.25	22.61	26.25	21.91	27.33	23.03	30.77	25.93
11	28.86	20.00	32.99	22.70	33.90	23.20	26.68	22.64	27.60	23.50	31.08	26.46
12	32.91	21.24	40.66	23.91	39.15	23.99	27.00	22.85	27.38	23.48	30.83	26.44
13	37.19	22.12	49.58	25.66	44.24	24.71	27.19	22.76	27.19	23.20	30.61	26.12
14	41.95	23.37	60.63	28.87	48.84	25.73	27.47	22.76	27.03	22.73	30.43	25.60
15	45.63	24.90	72.66	32.95	52.32	26.56	27.50	22.66	26.70	22.39	30.06	25.21
16	47.77	26.27	77.79	36.45	53.88	27.33	27.32	22.65	26.43	22.38	29.76	25.20
17	47.55	27.39	75.94	37.83	50.90	27.62	27.05	23.15	27.40	24.27	30.85	27.32
18	43.39	26.95	61.24	35.38	43.04	26.70	26.78	23.67	31.05	26.83	34.96	30.21
19	36.05	24.47	46.74	30.42	37.30	25.85	27.23	24.58	30.19	26.83	33.99	30.20
20	29.30	22.50	38.38	27.74	38.13	26.97	27.01	24.73	28.27	26.15	31.83	29.44
21	30.17	23.24	37.06	27.62	35.03	26.41	26.20	24.26	27.13	25.17	30.54	28.34
22	25.34	21.49	28.36	24.21	27.66	23.88	24.77	22.91	25.28	23.74	28.46	26.72
23	21.38	19.41	23.36	22.10	23.77	22.70	22.76	20.76	23.36	21.20	26.30	23.87
24	18.61	17.02	21.95	21.29	22.54	21.88	20.52	18.46	20.93	19.02	23.57	21.41

MARKET CLEARING PRICE
YEAR 2000
Monthly Hourly Prices
Average Weekday and Weekend Day
($s/MWh)

	January		February		March		April		May		June	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	21.47	20.30	21.19	20.04	18.53	17.52	15.95	14.40	7.74	7.51	5.78	5.31
2	20.69	19.35	20.42	19.10	17.85	16.70	14.44	12.76	5.70	5.30	3.50	3.52
3	20.05	18.32	19.80	18.09	17.31	15.81	13.71	11.59	4.73	3.91	2.46	1.89
4	20.33	18.14	20.07	17.91	17.55	15.66	13.55	11.45	4.56	3.24	2.19	0.91
5	21.80	18.59	21.52	18.36	18.81	16.05	14.44	11.75	5.92	3.52	3.50	0.93
6	25.22	20.14	24.90	19.88	21.77	17.38	17.34	12.68	10.75	4.33	7.56	1.35
7	28.44	22.44	28.08	22.15	24.55	19.36	21.90	14.33	18.13	6.25	14.35	2.14
8	30.13	24.09	29.74	23.78	26.00	20.79	24.27	15.82	22.56	9.52	19.83	6.73
9	31.30	26.05	30.90	25.72	27.02	22.48	25.35	17.56	26.90	12.79	24.14	9.44
10	31.86	26.85	31.45	26.51	27.50	23.17	26.17	19.26	30.48	15.21	28.54	12.50
11	32.18	27.40	31.77	27.05	27.77	23.65	26.63	20.34	32.46	16.80	31.72	15.74
12	31.92	27.37	31.52	27.03	27.55	23.63	26.75	20.71	33.33	17.53	33.06	17.54
13	31.70	27.04	31.29	26.70	27.36	23.34	26.78	20.50	33.61	17.29	34.13	18.27
14	31.50	26.50	31.10	26.17	27.19	22.87	26.75	20.35	33.96	17.16	35.82	18.93
15	31.12	26.10	30.73	25.76	26.86	22.52	26.67	20.10	33.45	16.78	36.31	19.38
16	30.81	26.09	30.42	25.76	26.59	22.52	26.51	19.99	32.52	16.73	36.16	20.04
17	31.94	28.29	31.53	27.93	27.57	24.42	26.15	19.96	31.30	17.48	34.93	21.29
18	36.19	31.28	35.73	30.88	31.24	27.00	25.68	20.36	29.33	17.67	32.28	20.85
19	35.19	31.27	34.75	30.87	30.37	26.99	25.70	21.37	27.03	17.01	28.56	19.01
20	32.96	30.48	32.54	30.09	28.44	26.31	26.46	23.20	28.18	18.30	26.08	17.40
21	31.62	29.34	31.22	28.97	27.29	25.32	26.55	23.93	32.46	23.31	30.13	21.92
22	29.46	27.67	29.09	27.32	25.43	23.88	25.44	22.24	27.13	20.08	25.73	19.30
23	27.23	24.71	26.89	24.40	23.50	21.33	23.02	19.74	18.70	14.67	18.89	14.61
24	24.40	22.17	24.09	21.88	21.06	19.13	18.93	16.21	13.00	9.61	10.93	7.98

MARKET CLEARING PRICE YEAR 2000
Monthly Hourly Prices
Average Weekday and Weekend Day
($s/MWh)

	July		August		September		October		November		December	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	16.39	15.39	25.59	24.77	25.83	25.41	20.16	19.34	19.88	18.79	20.86	19.72
2	14.23	12.48	24.05	22.05	24.86	23.93	18.13	16.83	19.15	17.91	20.10	18.80
3	12.59	10.12	22.60	19.44	24.00	22.26	17.01	14.88	18.57	16.97	19.48	17.80
4	12.06	8.77	21.83	17.71	23.60	21.17	17.08	14.41	18.83	16.80	19.76	17.63
5	12.99	8.89	22.67	17.34	24.56	21.24	19.10	14.88	20.18	17.22	21.18	18.07
6	15.67	10.17	25.25	18.61	26.31	22.59	22.88	17.00	23.35	18.65	24.50	19.57
7	18.98	11.77	27.13	21.11	27.98	23.74	26.73	19.65	26.34	20.77	27.64	21.80
8	20.59	14.29	28.28	22.83	29.72	24.76	27.88	21.63	27.90	22.31	29.27	23.40
9	22.08	16.63	29.80	25.29	32.21	26.12	28.80	23.45	28.98	24.12	30.41	25.31
10	25.05	18.83	33.02	26.74	34.96	27.02	29.21	24.38	29.50	24.86	30.96	26.09
11	29.21	20.25	40.06	27.57	40.51	27.73	29.69	25.20	29.79	25.37	31.26	26.62
12	33.32	21.50	49.38	29.04	46.79	28.67	30.06	25.43	29.56	25.35	31.02	26.60
13	37.65	22.39	60.22	31.17	52.88	29.54	30.27	25.33	29.35	25.04	30.80	26.27
14	42.47	23.65	73.64	35.06	58.38	30.75	30.57	25.33	29.17	24.54	30.61	25.75
15	46.20	25.21	88.25	40.02	62.53	31.74	30.61	25.23	28.82	24.16	30.24	25.36
16	48.36	26.60	94.48	44.26	64.40	32.67	30.41	25.21	28.53	24.16	29.93	25.35
17	48.14	27.73	92.23	45.95	60.84	33.01	30.11	25.76	29.57	26.20	31.03	27.49
18	43.92	27.28	74.38	42.97	51.45	31.91	29.81	26.34	33.51	28.96	35.17	30.39
19	36.50	24.77	56.77	36.95	44.59	30.90	30.31	27.35	32.59	28.96	34.19	30.38
20	29.67	22.78	46.61	33.70	45.58	32.24	30.07	27.52	30.52	28.22	32.02	29.61
21	30.55	23.53	45.01	33.54	41.87	31.57	29.16	27.00	29.28	27.17	30.72	28.51
22	25.65	21.76	34.44	29.41	33.07	28.54	27.57	25.50	27.28	25.62	28.63	26.88
23	21.64	19.65	28.37	26.84	28.41	27.13	25.33	23.10	25.22	22.88	26.46	24.01
24	18.84	17.23	26.66	25.86	26.94	26.15	22.84	20.54	22.59	20.53	23.71	21.54

MARKET CLEARING PRICE
YEAR 2001
Monthly Hourly Prices
Average Weekday and Weekend Day
($s/MWh)

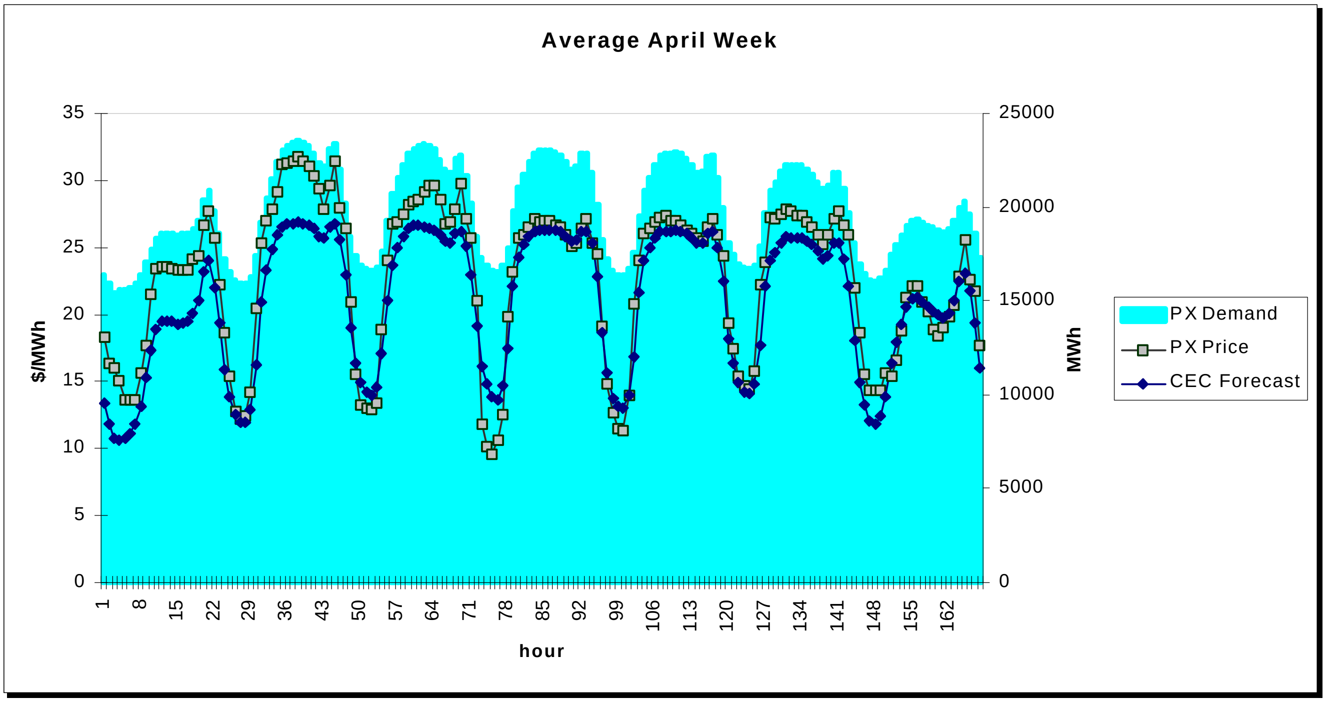
	January		February		March		April		May		June	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	22.24	21.02	20.76	19.63	19.75	18.68	16.33	14.74	8.15	7.91	6.28	5.77
2	21.43	20.04	20.01	18.71	19.04	17.80	14.79	13.06	6.00	5.58	3.80	3.82
3	20.77	18.98	19.39	17.72	18.45	16.86	14.03	11.87	4.98	4.12	2.67	2.05
4	21.06	18.79	19.66	17.55	18.71	16.69	13.87	11.72	4.81	3.41	2.38	0.99
5	22.58	19.26	21.08	17.98	20.06	17.11	14.79	12.04	6.24	3.71	3.81	1.01
6	26.12	20.86	24.39	19.47	23.21	18.53	17.76	12.98	11.33	4.56	8.21	1.47
7	29.46	23.24	27.51	21.70	26.17	20.64	22.43	14.67	19.10	6.59	15.58	2.33
8	31.21	24.95	29.14	23.30	27.72	22.17	24.86	16.20	23.76	10.03	21.53	7.31
9	32.42	26.98	30.27	25.19	28.80	23.97	25.96	17.98	28.34	13.48	26.22	10.25
10	33.00	27.81	30.81	25.97	29.32	24.71	26.80	19.72	32.11	16.03	30.99	13.57
11	33.33	28.38	31.12	26.50	29.61	25.21	27.27	20.83	34.19	17.69	34.45	17.10
12	33.07	28.36	30.87	26.47	29.37	25.19	27.39	21.21	35.11	18.46	35.90	19.04
13	32.83	28.01	30.65	26.15	29.17	24.88	27.43	20.99	35.40	18.22	37.06	19.84
14	32.63	27.45	30.47	25.63	28.99	24.39	27.40	20.84	35.77	18.08	38.90	20.56
15	32.24	27.03	30.10	25.24	28.64	24.01	27.31	20.58	35.24	17.67	39.43	21.05
16	31.91	27.03	29.79	25.23	28.35	24.01	27.14	20.47	34.26	17.63	39.27	21.77
17	33.08	29.30	30.89	27.36	29.39	26.03	26.78	20.44	32.98	18.41	37.93	23.12
18	37.49	32.40	35.00	30.25	33.30	28.78	26.29	20.85	30.89	18.62	35.05	22.64
19	36.45	32.39	34.04	30.24	32.38	28.77	26.32	21.88	28.48	17.92	31.02	20.64
20	34.14	31.57	31.87	29.48	30.33	28.05	27.10	23.75	29.68	19.28	28.32	18.90
21	32.76	30.39	30.58	28.38	29.10	27.00	27.19	24.51	34.19	24.55	32.72	23.80
22	30.52	28.66	28.49	26.76	27.11	25.46	26.05	22.77	28.58	21.16	27.95	20.96
23	28.21	25.60	26.34	23.90	25.06	22.74	23.57	20.21	19.70	15.45	20.51	15.87
24	25.27	22.96	23.60	21.44	22.45	20.40	19.39	16.60	13.70	10.13	11.86	8.67

MARKET CLEARING PRICE
YEAR 2001
Monthly Hourly Prices
Average Weekday and Weekend Day
($s/MWh)

	July		August		September		October		November		December	
Hour	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	18.46	17.33	28.16	27.25	25.49	25.07	20.93	20.07	20.59	19.46	21.61	20.43
2	16.02	14.05	26.46	24.25	24.53	23.61	18.81	17.47	19.84	18.55	20.83	19.48
3	14.17	11.40	24.86	21.39	23.68	21.96	17.66	15.44	19.23	17.57	20.19	18.45
4	13.58	9.87	24.02	19.48	23.29	20.89	17.72	14.96	19.50	17.40	20.47	18.26
5	14.63	10.00	24.94	19.07	24.24	20.95	19.82	15.44	20.90	17.83	21.94	18.72
6	17.64	11.45	27.78	20.47	25.96	22.29	23.75	17.64	24.19	19.31	25.39	20.27
7	21.37	13.25	29.84	23.22	27.61	23.43	27.74	20.39	27.28	21.52	28.63	22.59
8	23.19	16.09	31.11	25.12	29.33	24.43	28.94	22.45	28.89	23.10	30.33	24.25
9	24.86	18.73	32.78	27.82	31.79	25.77	29.90	24.34	30.02	24.98	31.51	26.22
10	28.20	21.20	36.33	29.42	34.50	26.66	30.32	25.31	30.55	25.75	32.07	27.03
11	32.89	22.80	44.07	30.33	39.98	27.36	30.82	26.16	30.86	26.27	32.39	27.58
12	37.52	24.21	54.33	31.95	46.17	28.29	31.20	26.40	30.61	26.25	32.14	27.56
13	42.39	25.22	66.25	34.29	52.18	29.15	31.41	26.29	30.40	25.93	31.91	27.22
14	47.82	26.64	81.02	38.58	57.60	30.34	31.73	26.29	30.21	25.42	31.72	26.68
15	52.02	28.38	97.09	44.03	61.70	31.32	31.77	26.18	29.85	25.03	31.33	26.27
16	54.46	29.95	103.94	48.70	63.54	32.23	31.56	26.16	29.54	25.02	31.02	26.27
17	54.21	31.23	101.47	50.55	60.03	32.57	31.25	26.74	30.63	27.13	32.15	28.48
18	49.46	30.72	81.83	47.27	50.77	31.49	30.94	27.34	34.71	30.00	36.44	31.49
19	41.10	27.89	62.45	40.65	44.00	30.49	31.46	28.39	33.75	29.99	35.43	31.48
20	33.41	25.65	51.28	37.07	44.97	31.81	31.21	28.56	31.61	29.23	33.18	30.69
21	34.40	26.49	49.52	36.90	41.31	31.15	30.26	28.02	30.32	28.14	31.83	29.54
22	28.89	24.50	37.89	32.35	32.63	28.16	28.61	26.46	28.26	26.53	29.66	27.86
23	24.37	22.13	31.21	29.53	28.04	26.77	26.29	23.98	26.12	23.70	27.42	24.88
24	21.22	19.40	29.32	28.45	26.58	25.81	23.71	21.32	23.40	21.26	24.56	22.32

APPENDIX C
COMPARISON OF PX ACTUAL PRICES TO
CEC FORECASTED PRICES

Figure C1


Average April Week
$/MWh
MWh
hour
PX Demand
PX Price
CEC Forecast
0
5
10
15
20
25
30
35
0
5000
10000
15000
20000
25000
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162

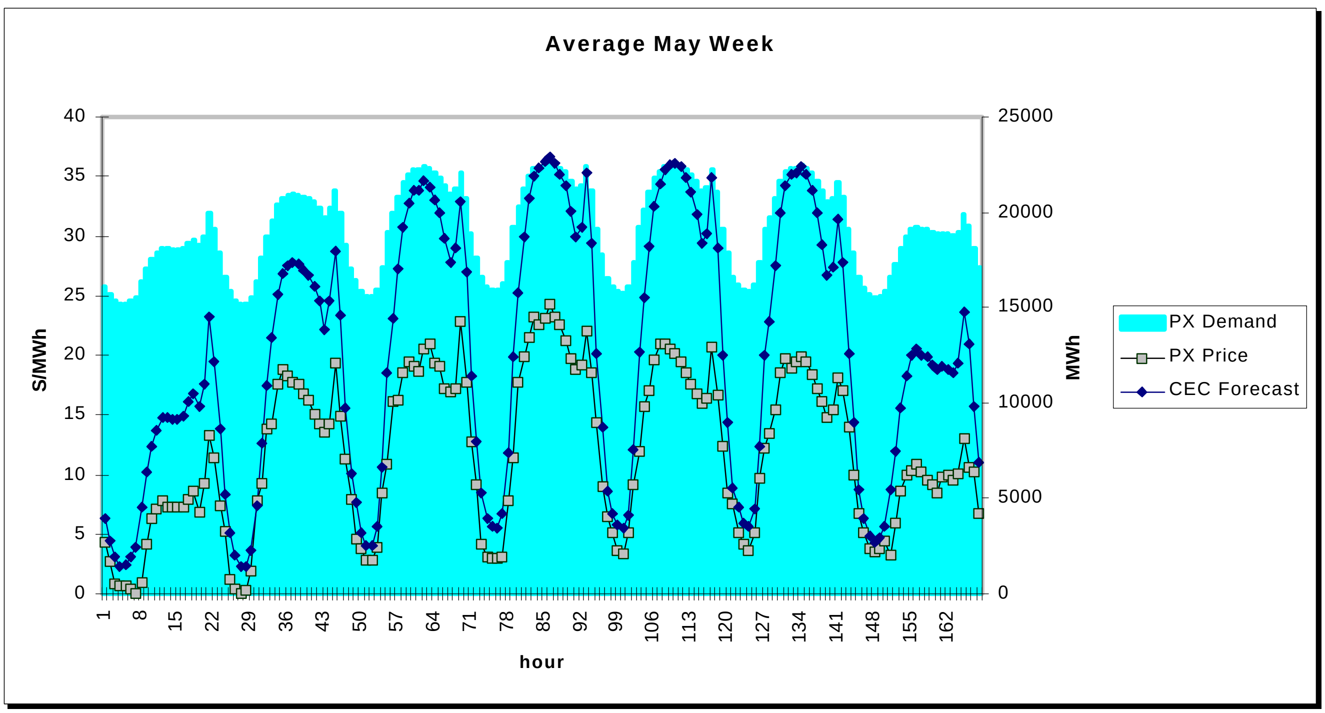
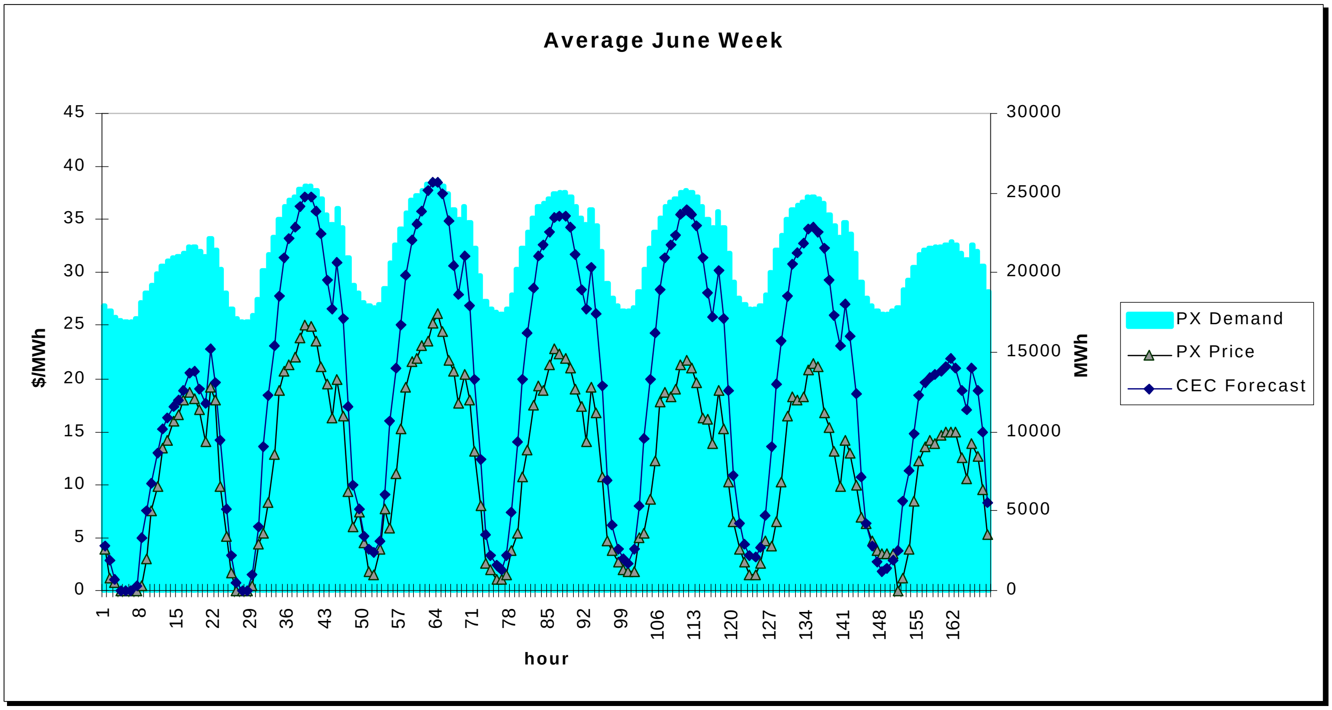

Average May Week
S/MWh
MWh
hour
PX Demand
PX Price
CEC Forecast
0
5
10
15
20
25
30
35
40
0
5000
10000
15000
20000
25000
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162

Figure C2


Average June Week
$/MWh
MWh
hour
PX Demand
PX Price
CEC Forecast
45
40
35
30
25
20
15
10
5
0
30000
25000
20000
15000
10000
5000
0
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162

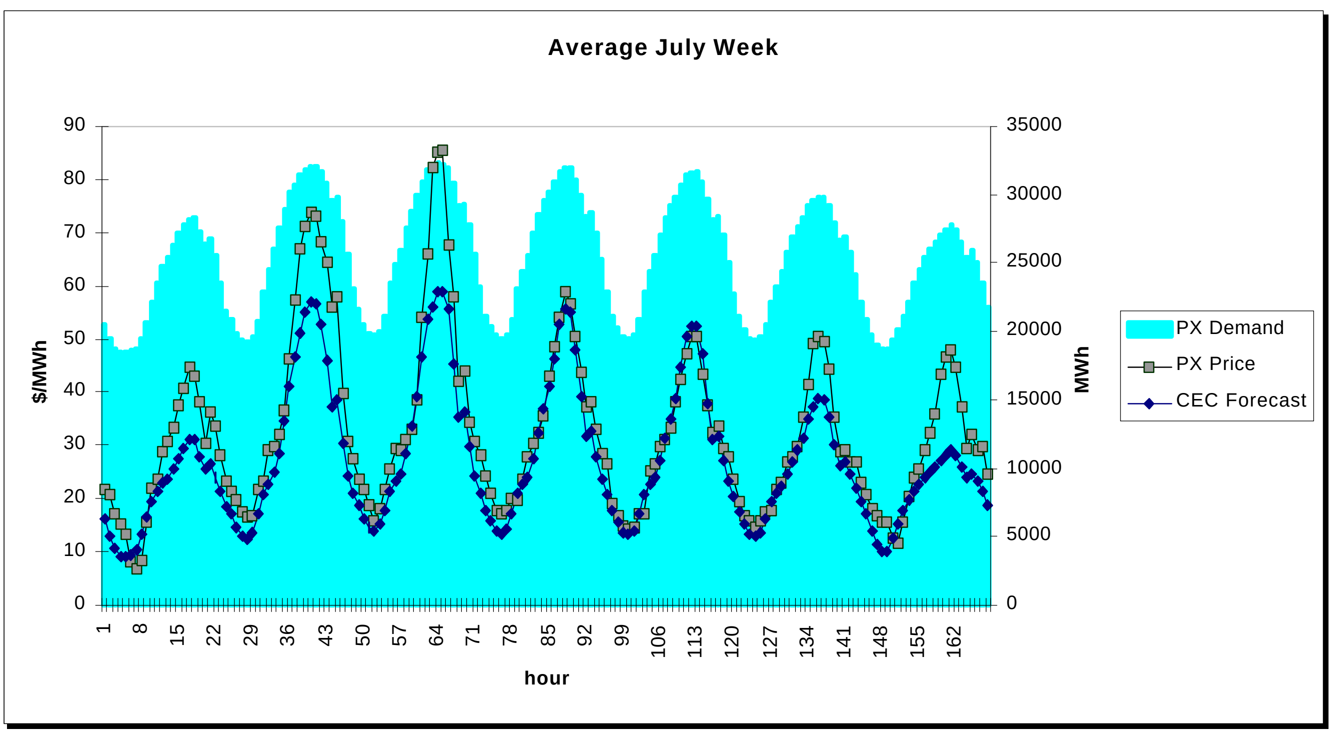
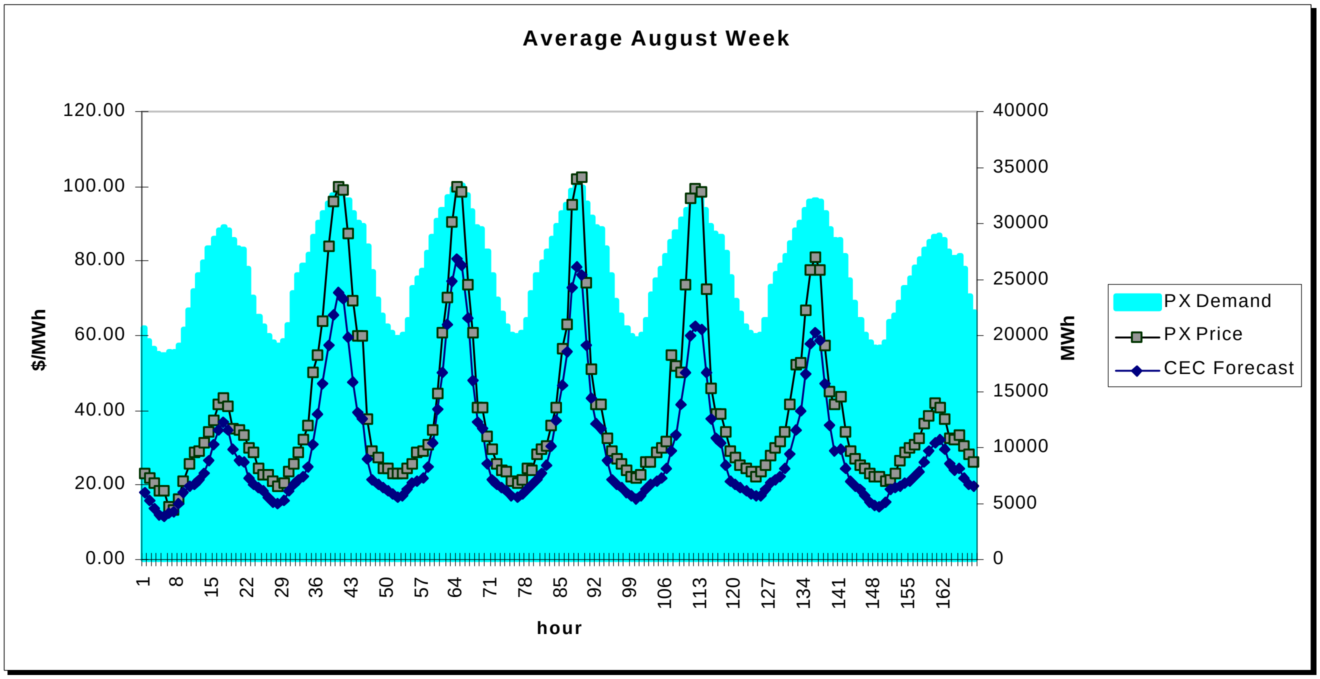
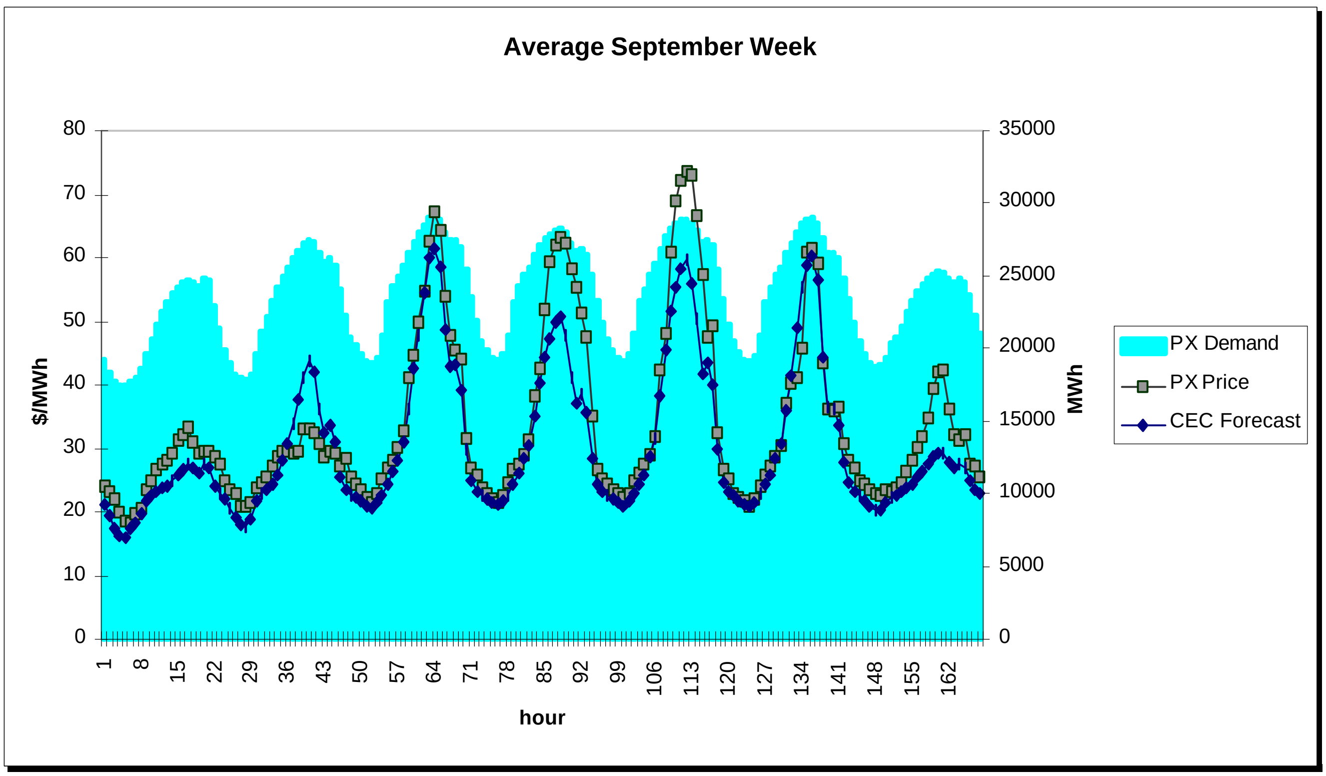

Average July Week
$/MWh
MWh
hour
PX Demand
PX Price
CEC Forecast
90
80
70
60
50
40
30
20
10
0
35000
30000
25000
20000
15000
10000
5000
0
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162

Figure C3

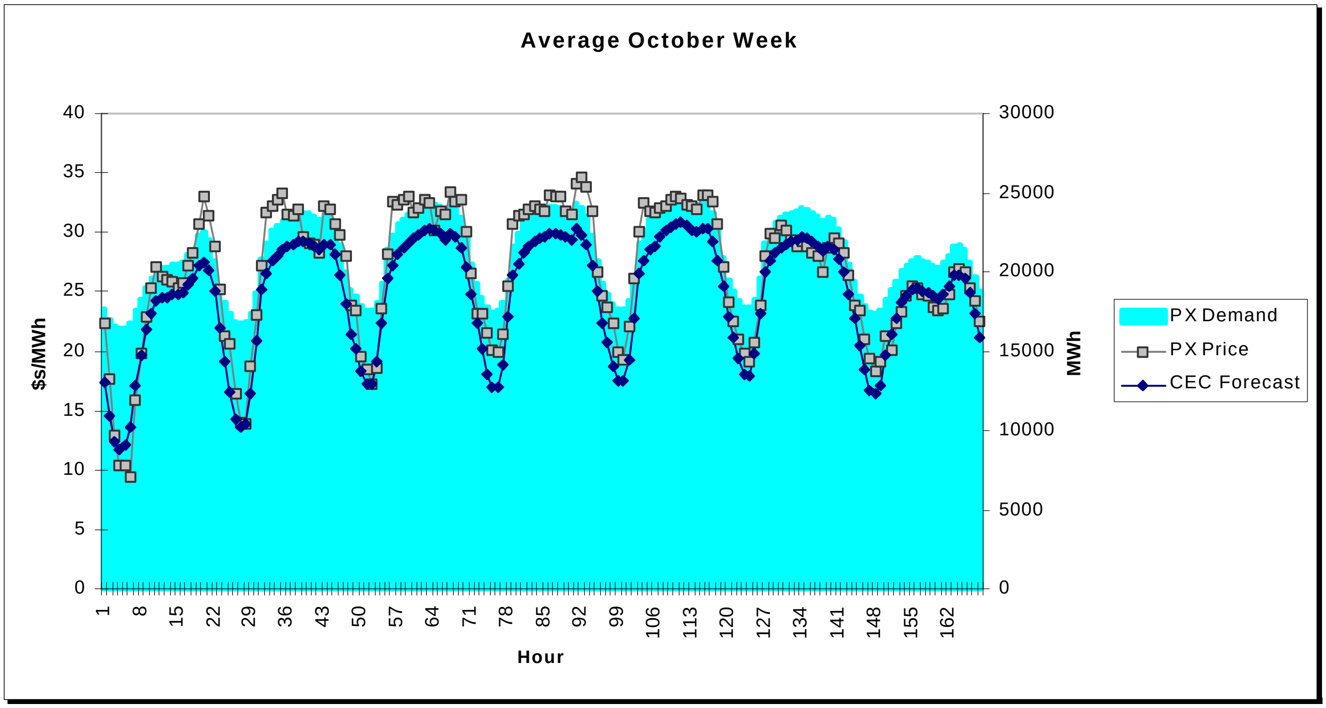


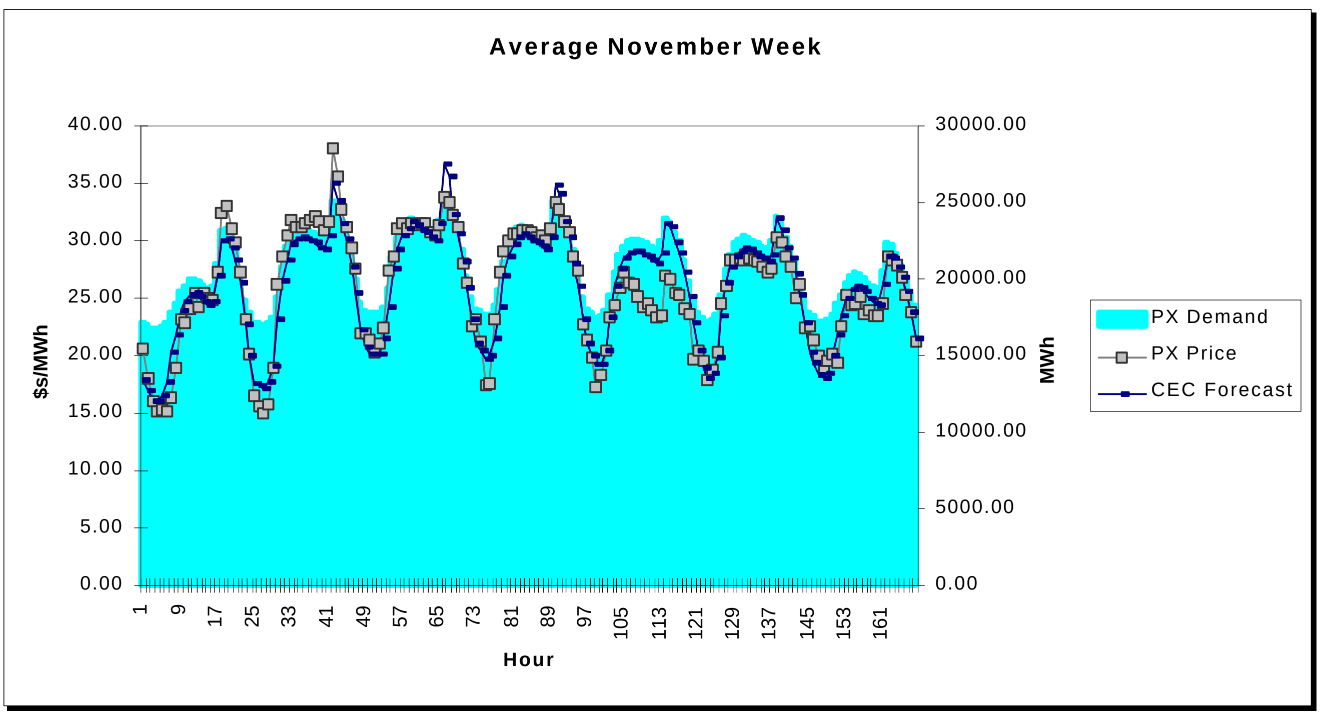
Average August Week
120.00
100.00
80.00
60.00
40.00
20.00
0.00
$/MWh
40000
35000
30000
25000
20000
15000
10000
5000
0
MWh
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
hour
PX Demand
PX Price
CEC Forecast



Average September Week
80
70
60
50
40
30
20
10
0
$/MWh
35000
30000
25000
20000
15000
10000
5000
0
MWh
1 8 15 22 29 36 43 50 57 64 71 78 85 92 99 106 113 120 127 134 141 148 155 162
hour
PX Demand
PX Price
CEC Forecast

Figure C4


Average October Week
40
35
30
25
20
15
10
5
0
$s/MWh
30000
25000
20000
15000
10000
5000
0
MWh
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
Hour
PX Demand
PX Price
CEC Forecast


Average November Week
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
$s/MWh
30000.00
25000.00
20000.00
15000.00
10000.00
5000.00
0.00
MWh
1
9
17
25
33
41
49
57
65
73
81
89
97
105
113
121
129
137
145
153
161
Hour
PX Demand
PX Price
CEC Forecast

APPENDIX D
HOURLY MCP SCALING METHODOLOGY

This Appendix describes staff's methodology for reshaping the UPLAN model's hourly Market Clearing Prices to be more comparable to the actual PX prices.

The hourly shape difference between the UPLAN model and the PX is illustrated in Figure D-1 using the month of April 1998. The actual PX MCPs have a distinctive shape, particularly in the on-peak period, which essentially follows the shape of the PX loads. The unscaled shape of the model output for this month is relatively flat and shapeless through the on-peak period. Also, the off-peak excursions are, for the most part, less pronounced than that indicated by the actual PX prices.

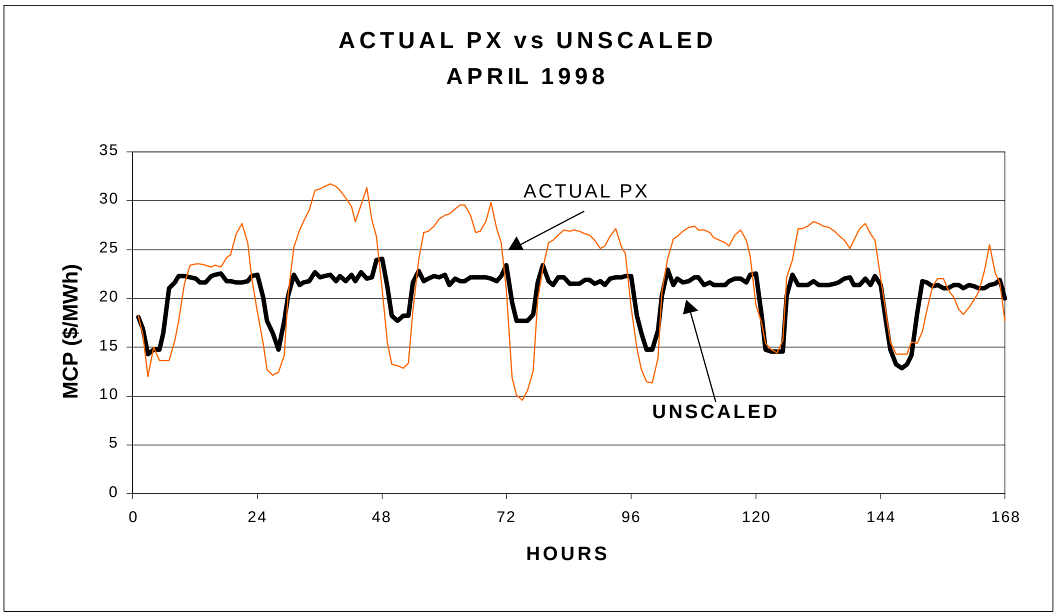


Figure D-1

The Reshaping Methodology

Our methodology for reshaping the UPLAN output, while simplistic, is nevertheless effective in producing hourly MCPs that are more comparable to those of the PX. The process consists of defining the relationship between the actual PX prices and loads as a curve and then linearly scaling that curve to match the average monthly MCPs of the forecasting model. The step-by-step process is as follows.

The first step in the process involves the development of an equivalent week for each month of the PX data so that it is comparable to the data produced by the UPLAN model. This is done by averaging the hourly PX price and load data for each month into one equivalent week of 168 hours. Figure D-2 shows this for the April 1998 PX data. The shaded area shows the average PX loads and the heavy dark line is a plot of average PX prices. Despite minor excursions the PX prices follow the PX loads closely.

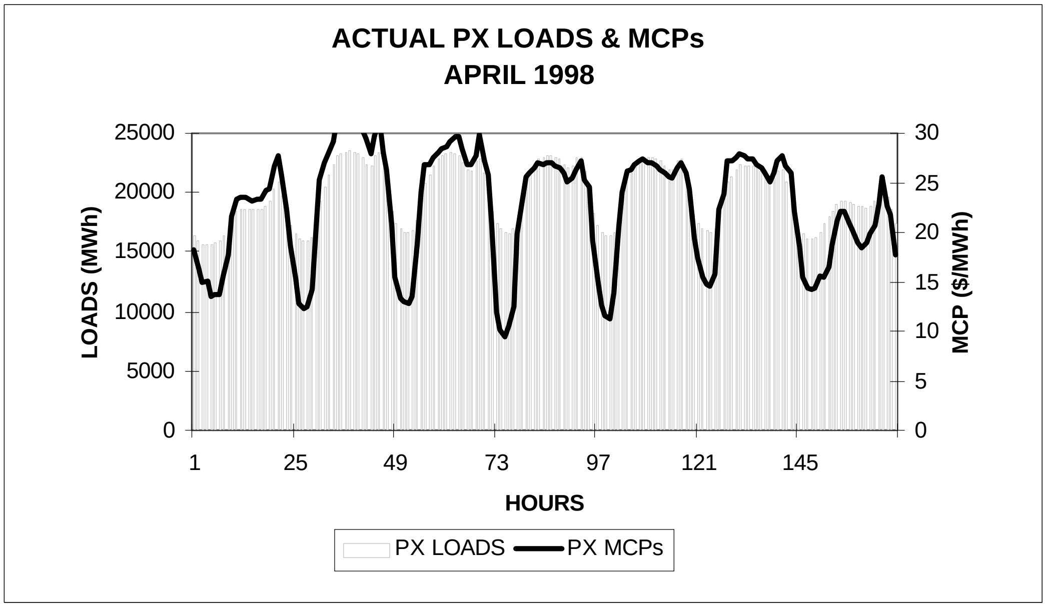


Figure D-2

Figure D-3 shows the same data in a different format: MCPs as a function of increasing loads (MW). An Excel spreadsheet is used to produce this graph and an associated trendline. In this particular month, the trendline is represented by a second order equation, as this was found to provide the best fit. In other months, a first order or third order equation is sufficient.

$$MCP = -1.903x10^{-7} * Load^2 + 0.00963 * Load - 92.451$$

Where: ***MCP = PX Hourly Market Clearing Prices ($/MWh)***

Load = PX Hourly Loads (MWh)

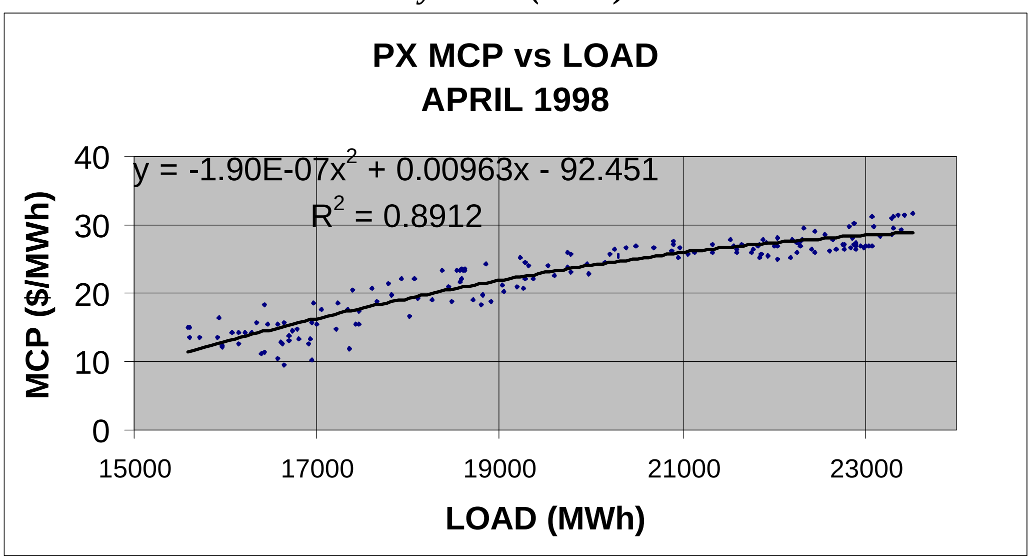


Figure D-3

Figure D-4 is similar to Figure D-2 but in this case compares the shape of the MCPs, as represented by the trendline, to the actual PX loads. As would be expected, this reshaping of the MCPs fits the load's shape even better than the actual PX MCPs.

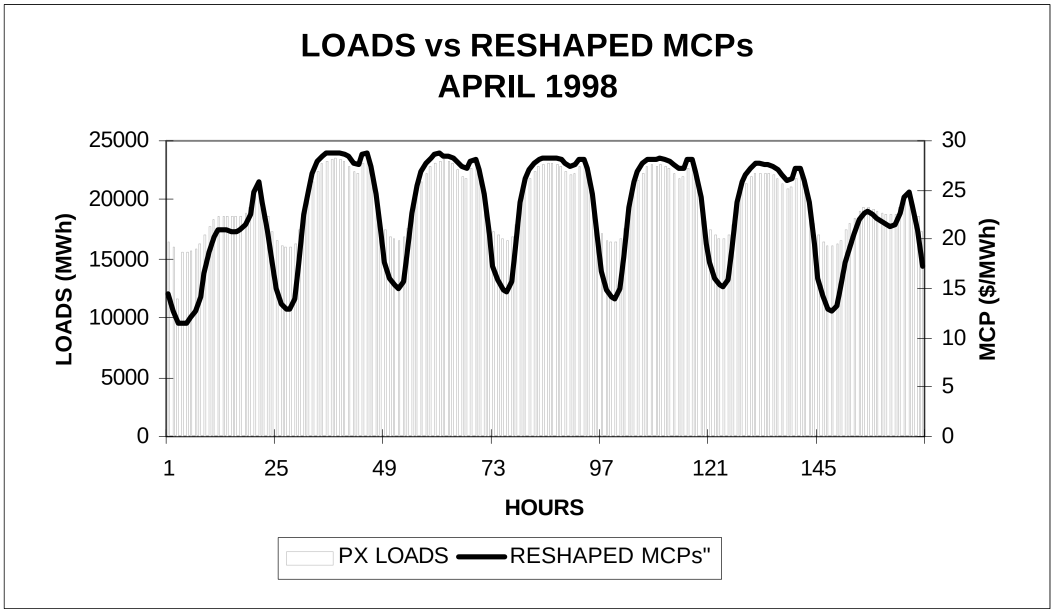


Figure D-4

The final step in this process is to linearly scale the new curve of PX MCPs to match the monthly average MCPs from the UPLAN model. Figure D-5 shows the scaled values (CEC Scaled) compared to the unscaled output of the UPLAN model. The "CEC Scaled" values become the California Energy Commission official hourly forecast.

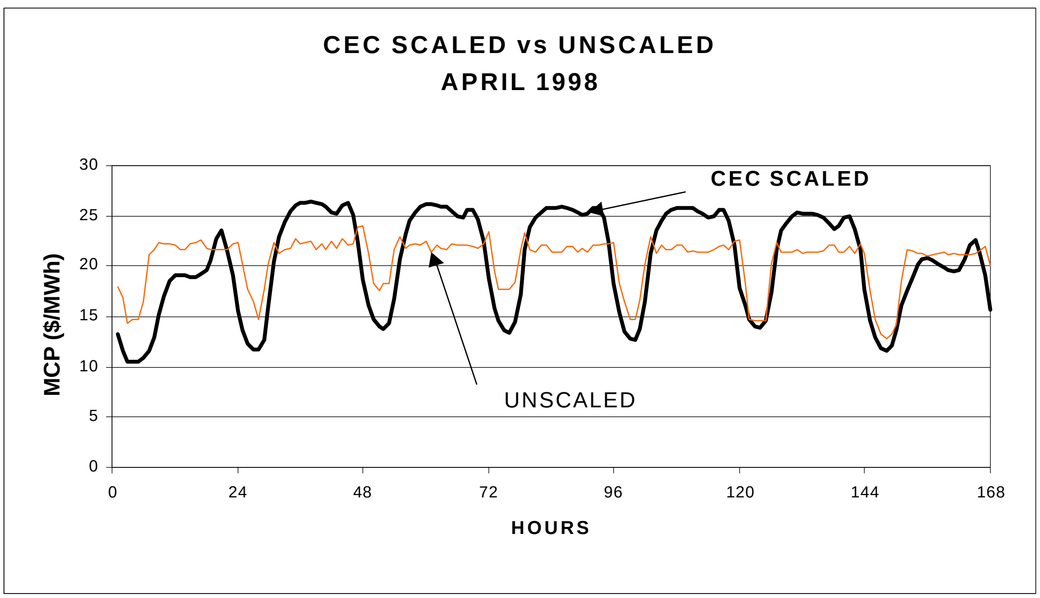


Figure D-5

Figure D-6 compares the "CEC scaled" MCPs to those of the PX. While the UPLAN forecasted average April MCP is about 8 percent lower than the actual PX value, it is clear that the scaled hourly MCPs, and therefore the on-peak/off-peak numbers, are more comparable to the actual PX values than the unscaled MCPs.

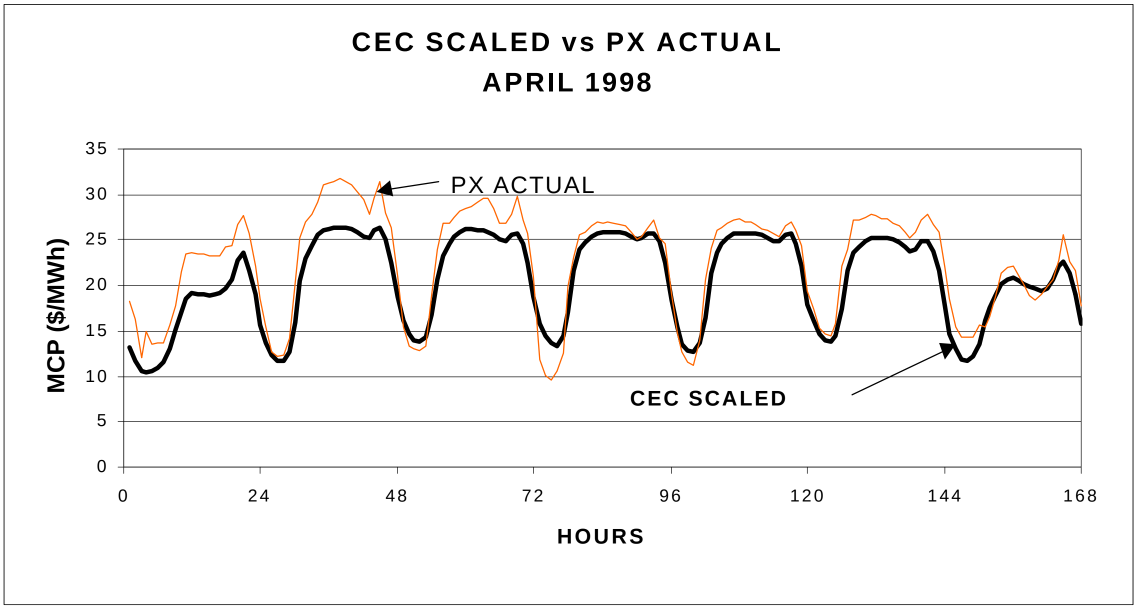


Figure D-6

Since there are no PX MCPs for the months of December through March, November's scaling routine is used as a proxy. We believe using November as a proxy was a reasonable approach to take after comparing the combined loadshapes for the three California IOUs, PG&E, SCE and SDG&E, for November through March.[13] This assumes that the combined IOU loadshapes are a reasonable proxy for the actual PX loadshape. Figure D-7 illustrates that the loadshapes - not the absolute values - for these months are very similar.

[13] The IOU loadshapes are taken from the ER 96 loadshapes, which are then scaled up to match ER 96 forecasted 1998 peak and energy values. The peak and energy values are for the service area – as opposed to planning area.

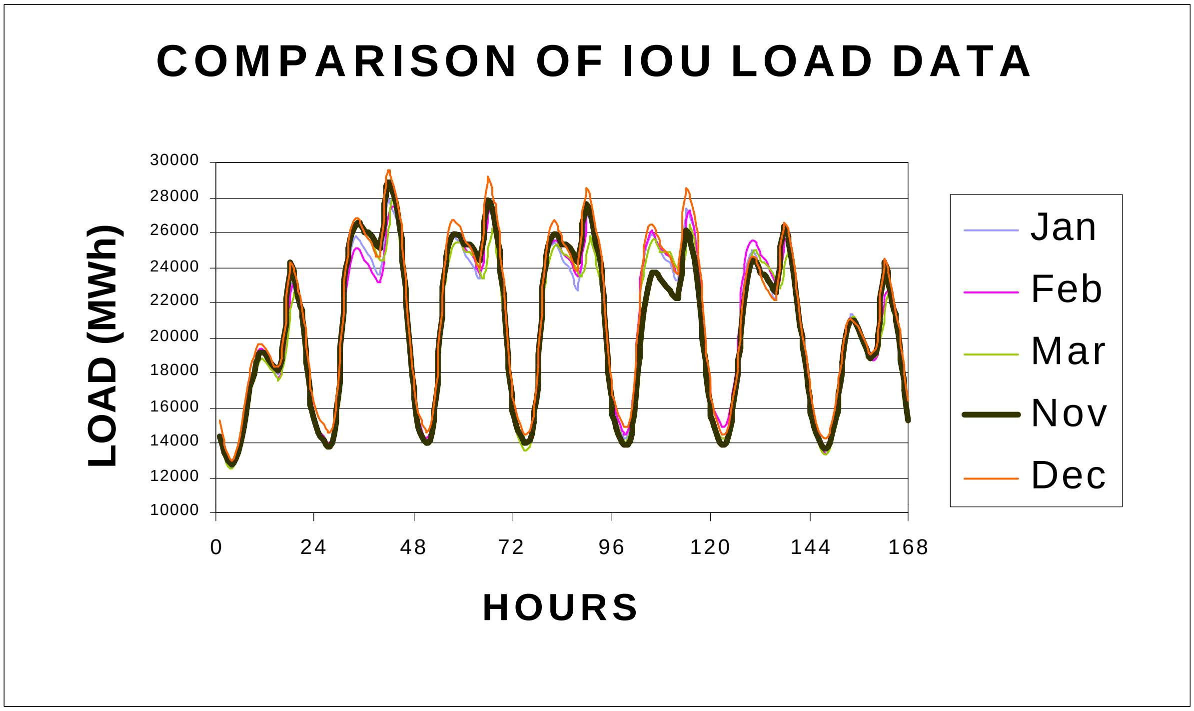
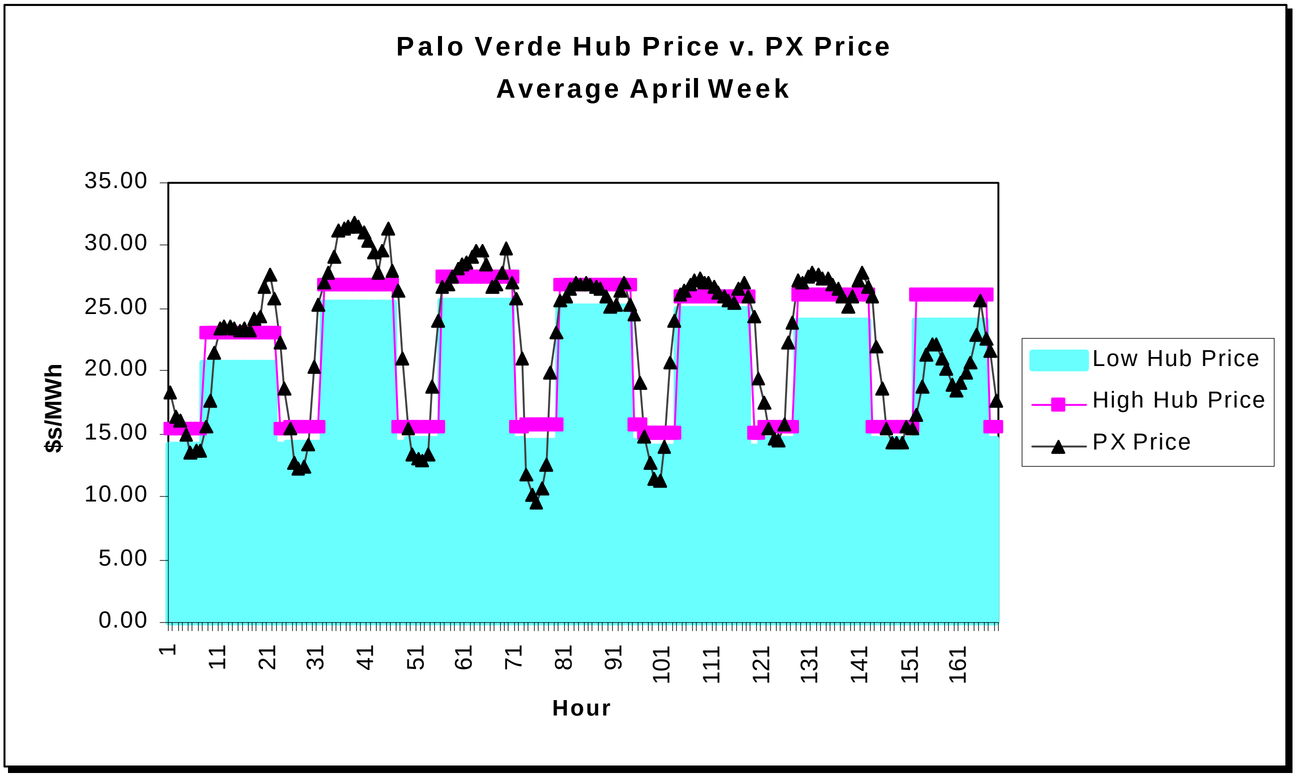

COMPARISON OF IOU LOAD DATA
LOAD (MWh)
30000
28000
26000
24000
22000
20000
18000
16000
14000
12000
10000
0
24
48
72
96
120
144
168
HOURS
Jan
Feb
Mar
Nov
Dec

Figure D-7

APPENDIX E
COMPARISON OF PX ACTUAL PRICES TO
PALO VERDE AND COB HUB SPOT PRICES

Figure E1


Palo Verde Hub Price v. PX Price
Average April Week
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
$s/MWh
1
11
21
31
41
51
61
71
81
91
101
111
121
131
141
151
161
Hour
Low Hub Price
High Hub Price
PX Price

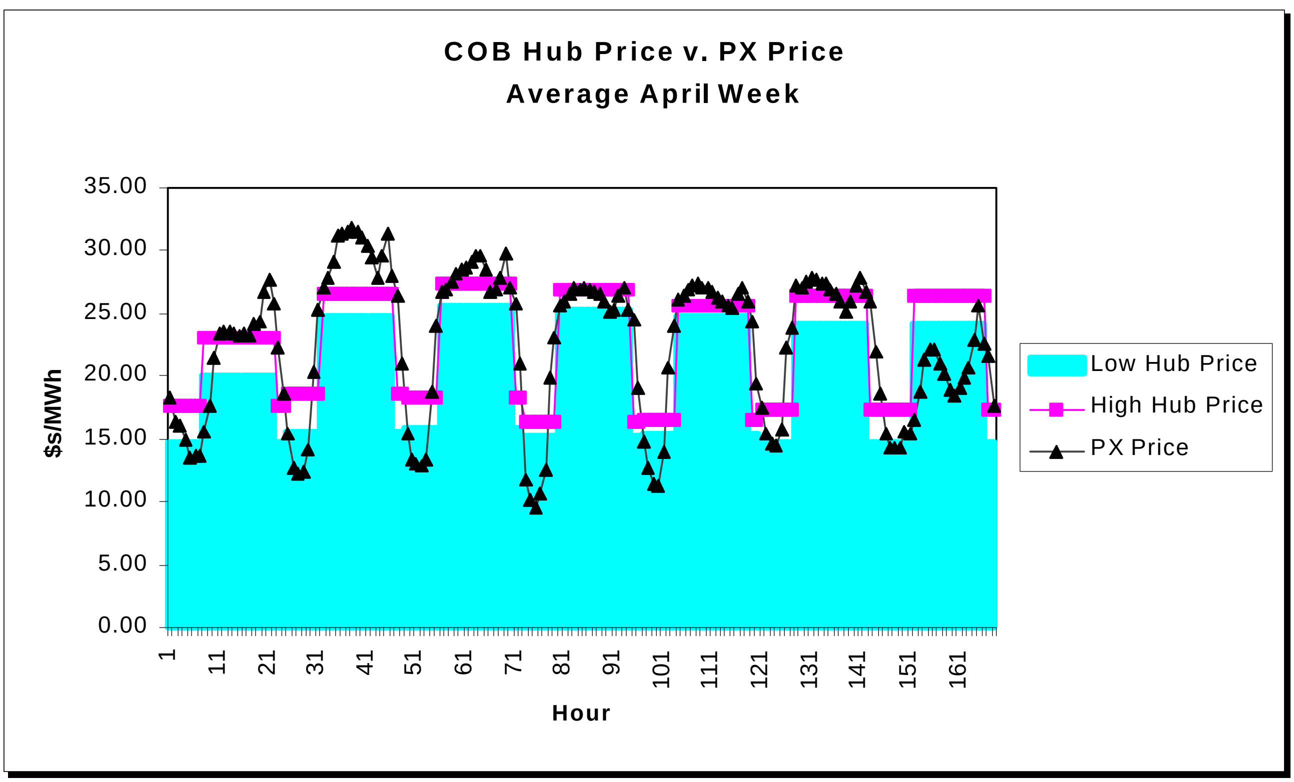
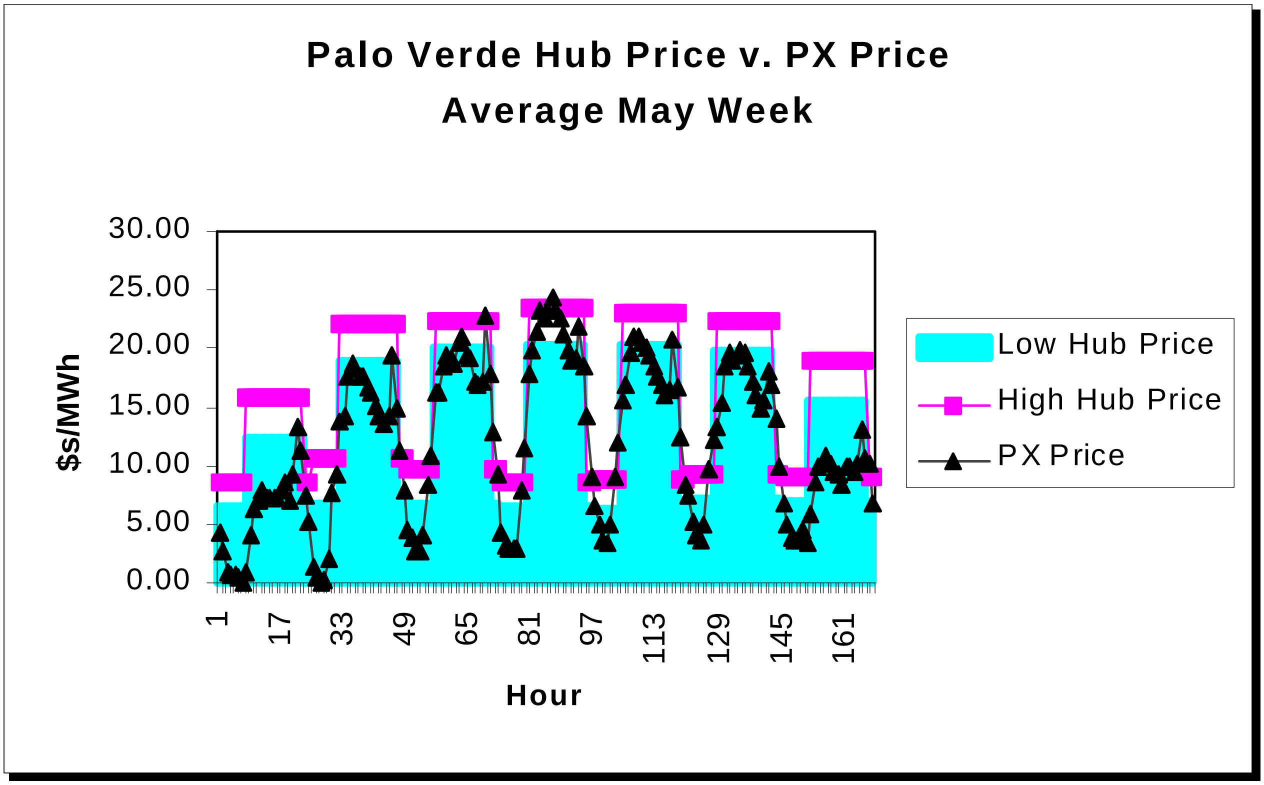

COB Hub Price v. PX Price
Average April Week
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
$s/MWh
1
11
21
31
41
51
61
71
81
91
101
111
121
131
141
151
161
Hour
Low Hub Price
High Hub Price
PX Price

Figure E2


Palo Verde Hub Price v. PX Price
Average May Week
$s/MWh
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1
17
33
49
65
81
97
113
129
145
161
Hour
Low Hub Price
High Hub Price
PX Price

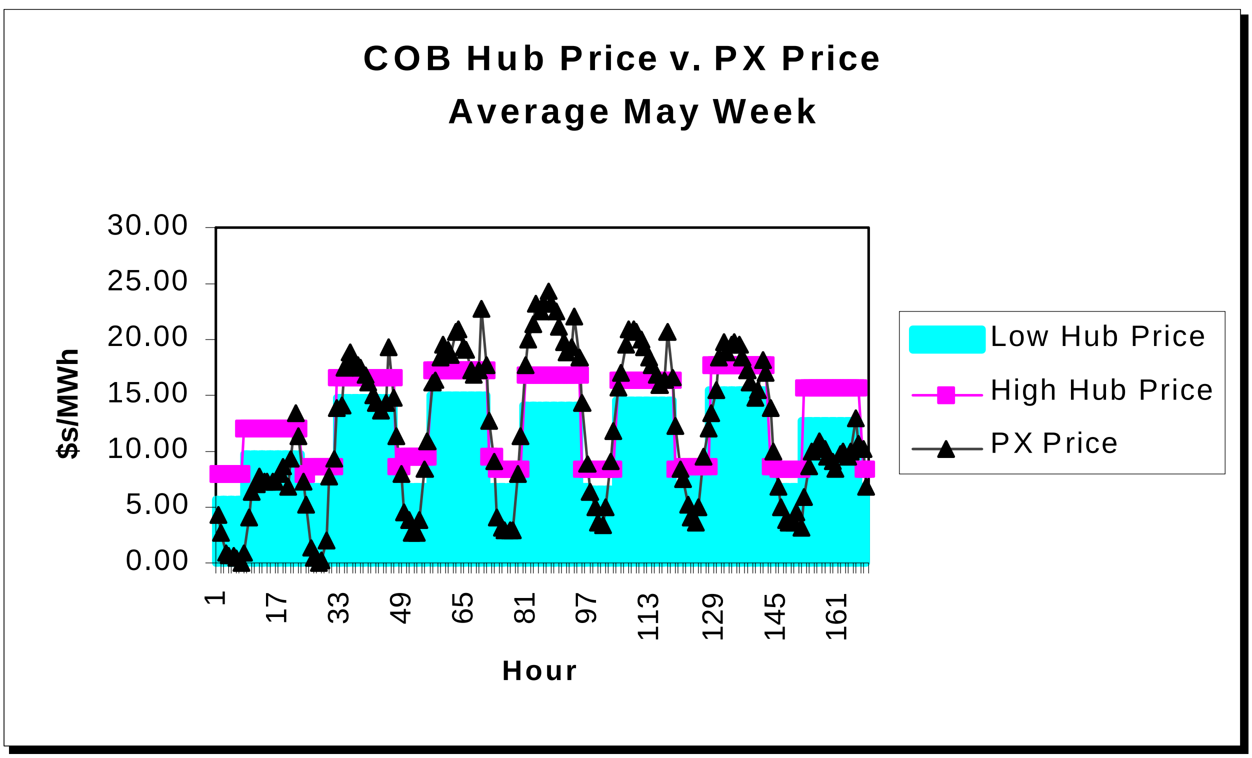
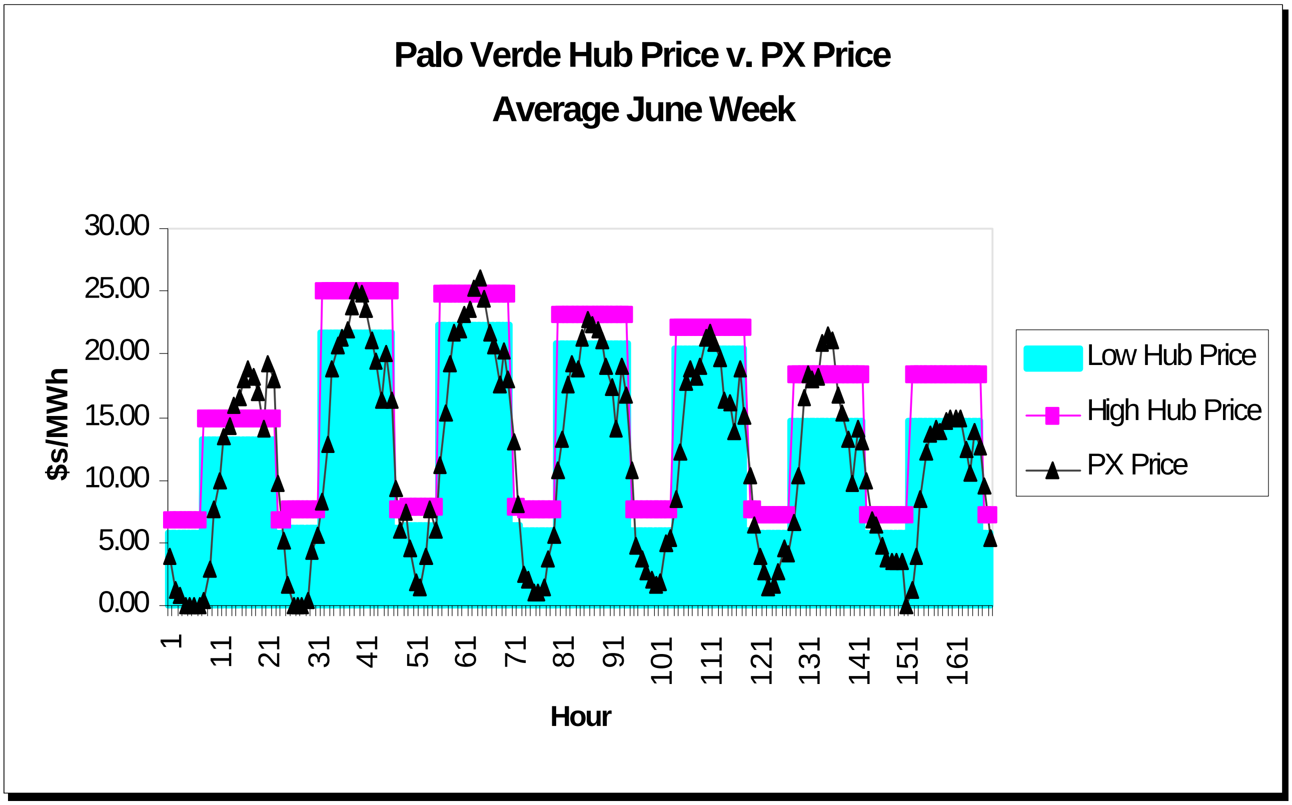

COB Hub Price v. PX Price
Average May Week
$s/MWh
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1
17
33
49
65
81
97
113
129
145
161
Hour
Low Hub Price
High Hub Price
PX Price

Figure E3


Palo Verde Hub Price v. PX Price
Average June Week
$s/MWh
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1
11
21
31
41
51
61
71
81
91
101
111
121
131
141
151
161
Hour
Low Hub Price
High Hub Price
PX Price

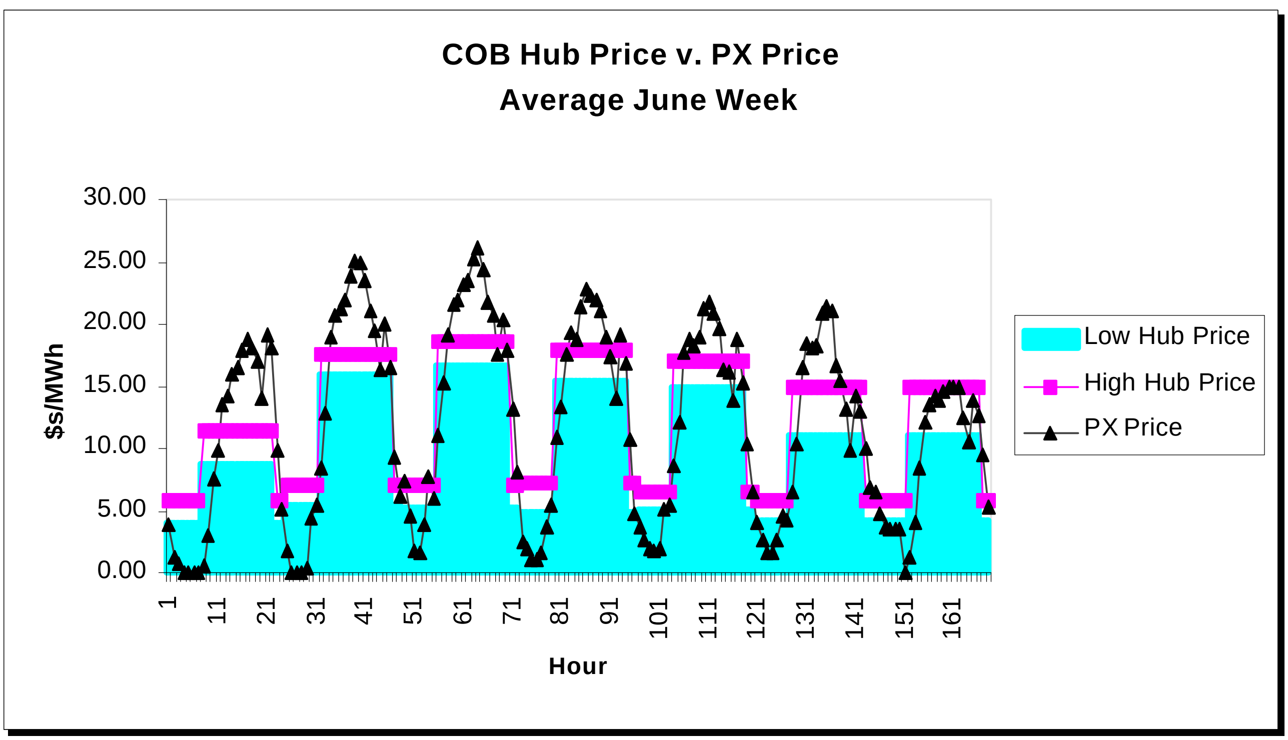
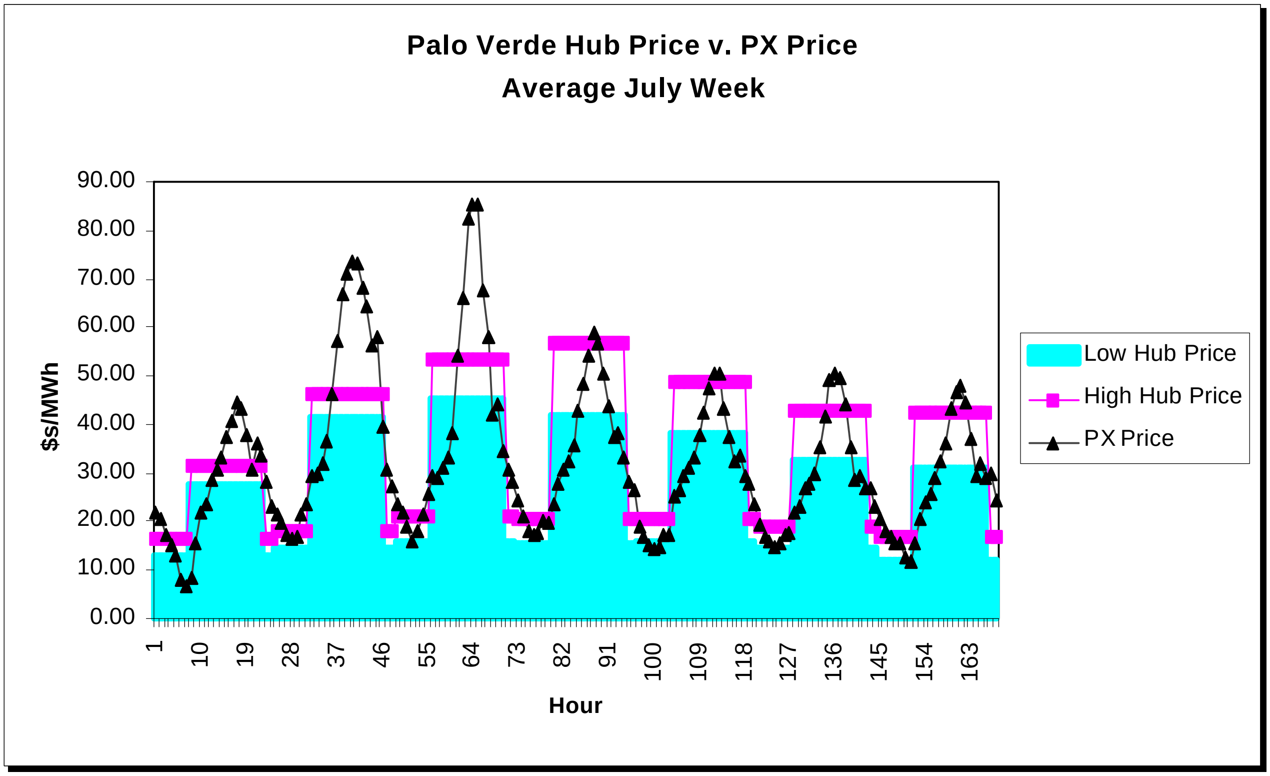
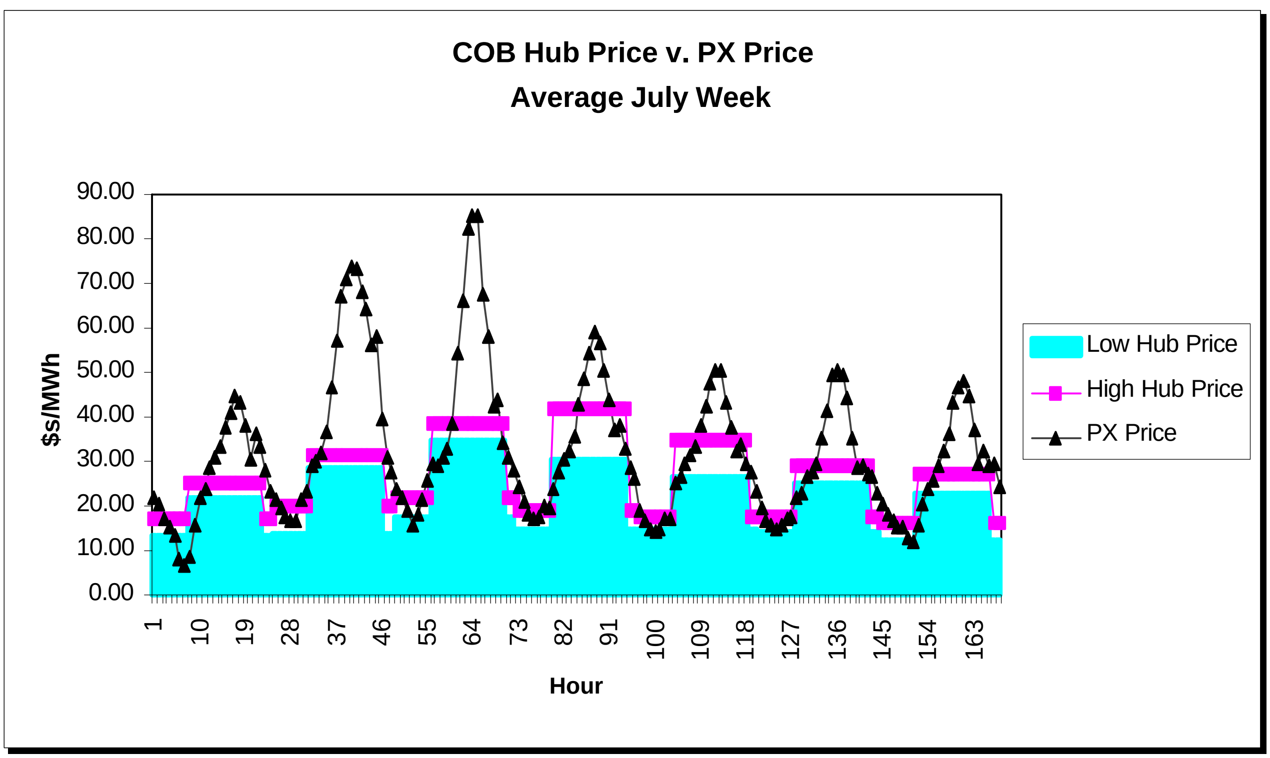

COB Hub Price v. PX Price
Average June Week
$s/MWh
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1
11
21
31
41
51
61
71
81
91
101
111
121
131
141
151
161
Hour
Low Hub Price
High Hub Price
PX Price

Figure E4

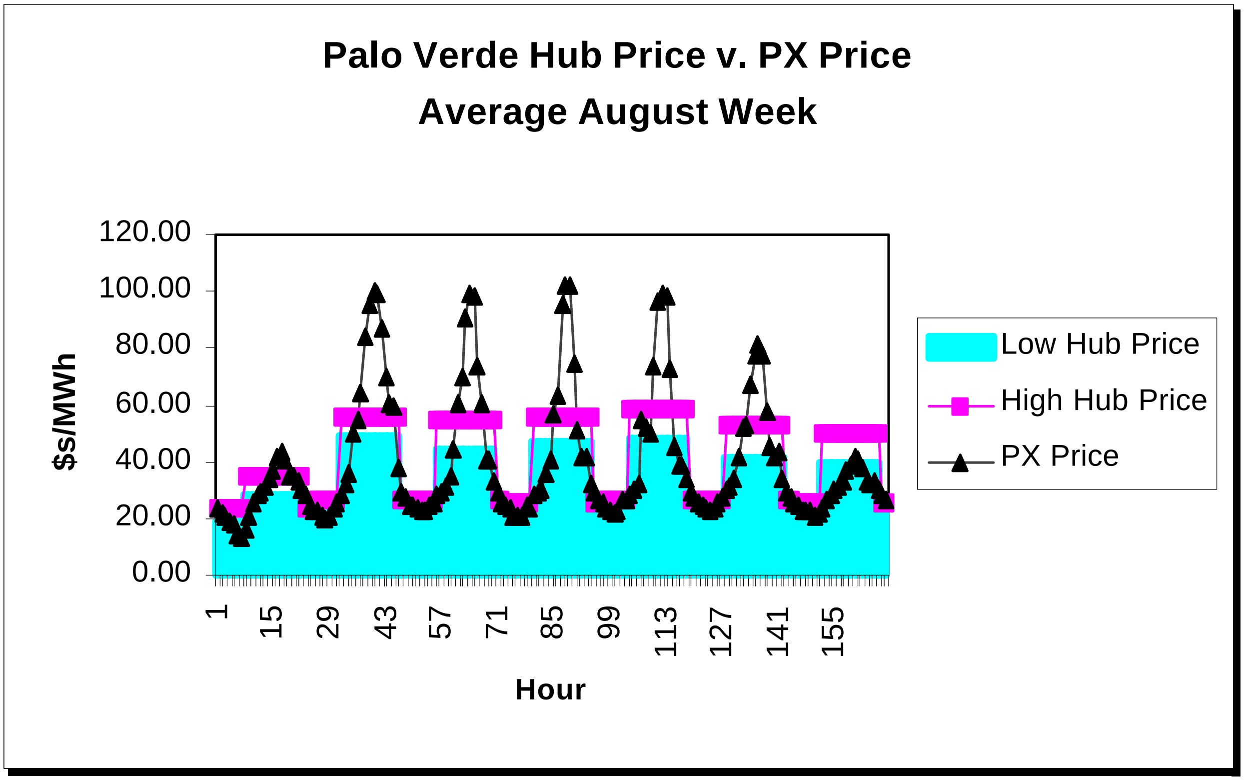


Palo Verde Hub Price v. PX Price
Average July Week
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$s/MWh
1
10
19
28
37
46
55
64
73
82
91
100
109
118
127
136
145
154
163
Hour
Low Hub Price
High Hub Price
PX Price

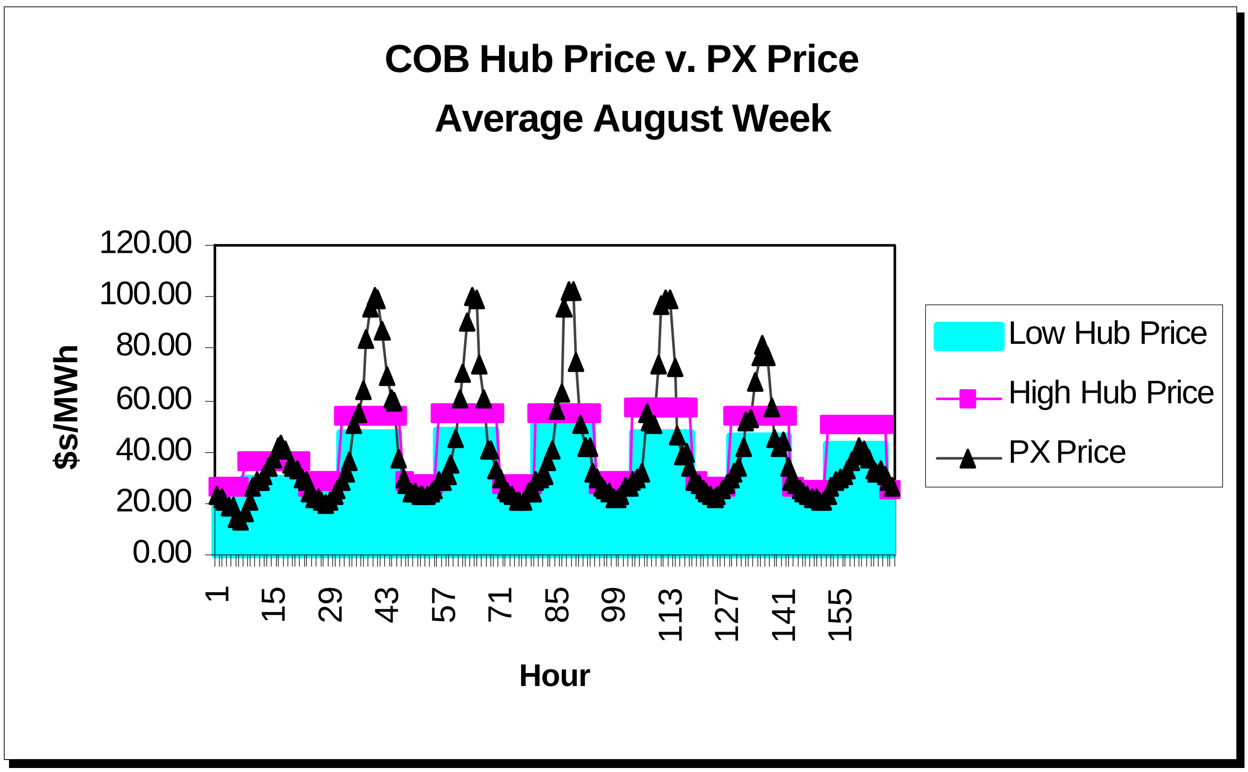


COB Hub Price v. PX Price
Average July Week
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$s/MWh
1
10
19
28
37
46
55
64
73
82
91
100
109
118
127
136
145
154
163
Hour
Low Hub Price
High Hub Price
PX Price

Figure E5

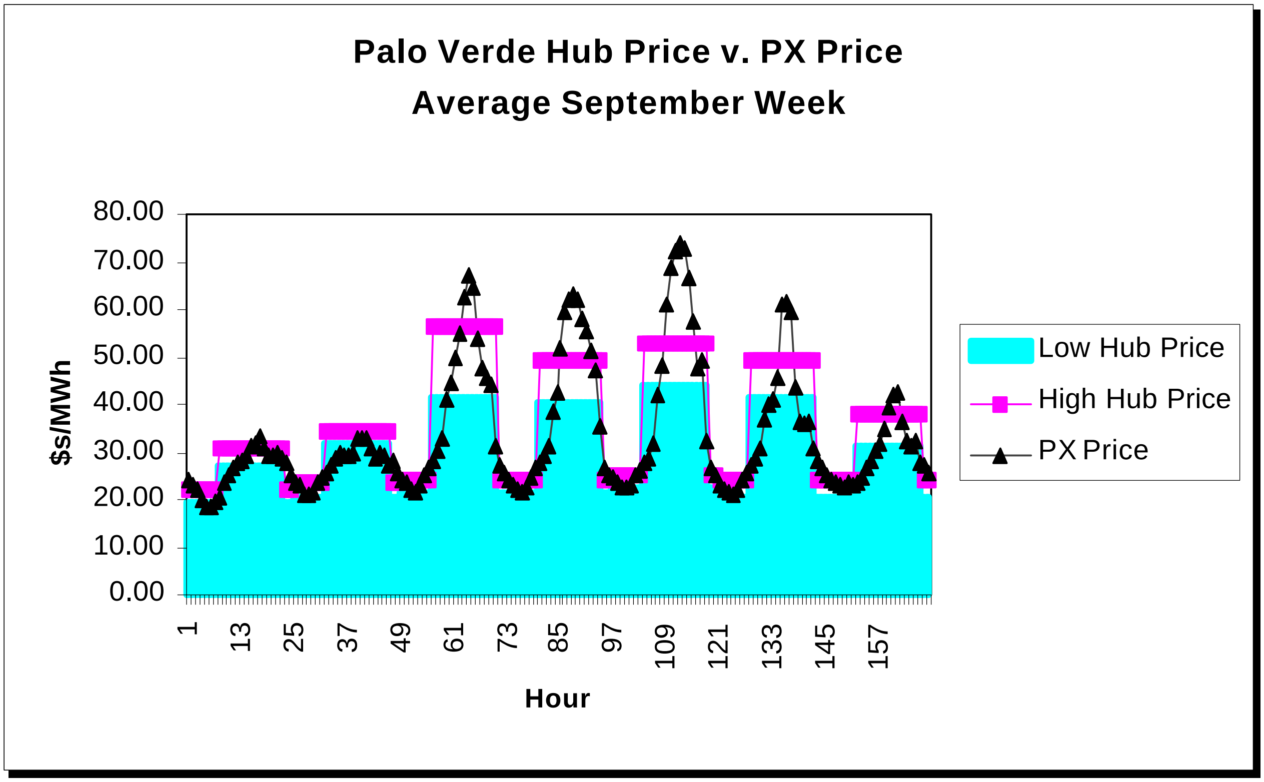


Palo Verde Hub Price v. PX Price
Average August Week
120.00
100.00
80.00
60.00
40.00
20.00
0.00
$s/MWh
1
15
29
43
57
71
85
99
113
127
141
155
Hour
Low Hub Price
High Hub Price
PX Price

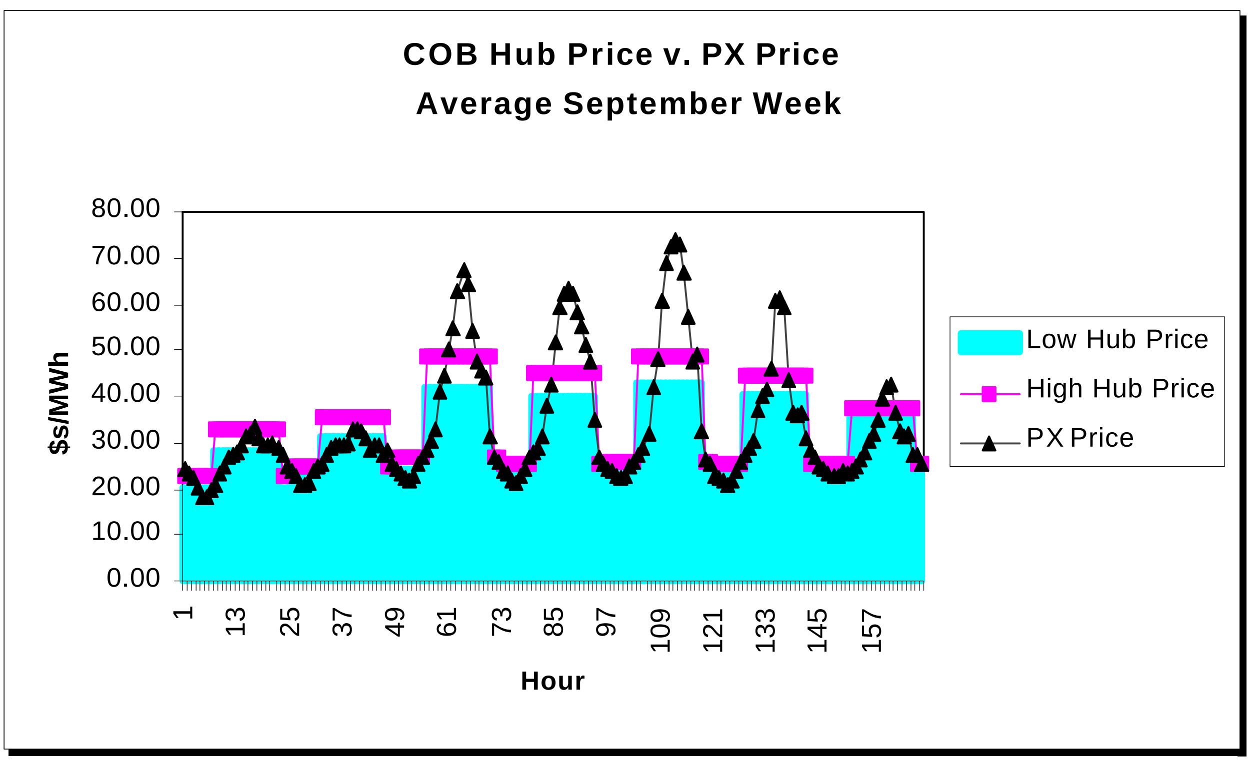


COB Hub Price v. PX Price
Average August Week
120.00
100.00
80.00
60.00
40.00
20.00
0.00
$s/MWh
1
15
29
43
57
71
85
99
113
127
141
155
Hour
Low Hub Price
High Hub Price
PX Price

Figure E6



Palo Verde Hub Price v. PX Price
Average September Week
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$s/MWh
1
13
25
37
49
61
73
85
97
109
121
133
145
157
Hour
Low Hub Price
High Hub Price
PX Price



COB Hub Price v. PX Price
Average September Week
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
$s/MWh
1
13
25
37
49
61
73
85
97
109
121
133
145
157
Hour
Low Hub Price
High Hub Price
PX Price

APPENDIX F
COST OF NEW ENTRANTS

The economic viability of existing and new units will depend on their ability to cover their costs from the income they can earn. For most generators bidding into the PX, their net income will be the difference between their total income, based on the MCP paid for their generation and their fixed and variable costs. Some existing generators will receive additional income under reliability contracts with the ISO. Existing utility-owned generators that are not divested, however, will have the recovery of their remaining fixed capital costs guaranteed through the CTC during the transition period. The only costs that these existing generators have at risk are their fixed O&M costs. The utility generator can either hope that the MCP is sufficient to cover both fixed and variable O&M, or if the generator is designated as needed for reliability purposes, that it can recover its costs through a reliability contract with the ISO. A new generator bidding into the PX does not have its capital costs covered under the CTC, and most likely will not have a reliability must-run contract with the ISO. Its total costs, capital and fixed and variable O&M must be recovered from revenue it receives from bidding into the PX energy market and the ISO's ancillary services market.

Existing generators in California that are not divested or needed for reliability will have recovery of their capital costs guaranteed through either the CTC or through contracts with the ISO. The expectation is that these generators will have a strong incentive to bid close to their variable operating cost and therefore set the MCP for most hours of the day. If this is the case, the MCP during the transition period will closely approximate the variable operating cost of existing utility generators. Even though the efficiency of the new units, such as gas-fired combined cycle plants, is significantly greater than that of the existing utility units, the resulting difference in operating costs may not be enough for new generators to recover all of their costs.[14] As the system needs new capacity, the MCP will have to rise to attract new generators.

What are the costs that a new entrant into the market needs to recover from the MCP? The answer to this is sensitive to several assumptions regarding the plant’s capacity factor, its efficiency, fixed and variable non-fuel operating costs, fuel-related operating costs, and construction cost.

The plant’s capacity factor is typically a function of system demand, and its own availability. Stone & Webster in their work for the Commission’s ***Energy Technology Status Report*** reported that a combined cycle plant operating in the base load mode would have an expected capacity factor of 85 percent. However, it could vary from 50 to 95 percent depending on load conditions and where the plant is in its maintenance cycle. A plant’s availability factor reflects the number of

[14] Recently built combined cycle facilities have an average heat rate of around 7,200 Btu/kWh. This assumes that the plant is operating near full capacity in all hours of operation (i.e. in a base load mode). The system average heat rate for existing utility gas-fired units in California is around 11,000 Btu/kWh.

hours it is available to run. An availability factor of 93 percent is a reasonable expectation, based on a nominal forced outage rate of 2 percent and maintenance outage rate of 5 percent.[15]

The efficiency of the plant is measured by its heat rate. For recently built combined cycle plants, such as the GE 7FA, the Westinghouse 501G, the ABB GT24, and the Siemens V84.3A, the heat rate is around 7,200 Btu/kWh, assuming that they are operating primarily at their full load level. Further heat rate improvements are expected. The GE 7H combined cycle plant, which became available in 1997, is reported to have a heat rate of 6,300 Btu/kWh (high heat rate value).[16]

A plant's non-fuel O&M will vary depending on several factors. For this analysis the fixed and variable non-fuel O&M costs for a typical 220 MW, base-loaded combined cycle plant are estimated to be $22/kW-yr and $1.8/MWh (in 1998 $), respectively. The fixed O&M cost would be approximately $13/kW-yr for an intermediate-duty plant.[17] The plant's fuel-related O&M costs are the product of the assumed heat rate and fuel cost.

The ***instant cost***[18] of building a combined cycle plant or its "lump-sum, turnkey" (LSTK) price at a new site ranges from $553 to $803/kW (1998 dollars)[19]. This includes transmission interconnection costs, but does not include any transmission upgrade costs. The costs of recently installed combined cycle plants suggest that the price is more likely to be in the $800/kW range.[20]

The following assumptions are used to calculate a range of MCPs that would be needed to attract a new combined cycle plant in 1998.

Installed Plant Capacity	220 MW
Instant Plant Cost	$553 - $803/kW
Fixed Charge Rate	15%
Heat Rate	6300 - 7200 Btu/kWh
Fixed Non-fuel O&M	$22/kW-yr
Variable Non-fuel O&M	$1.8/MWh
Gas Price (1998 $s)	$2.20 - $2.50/MMBtu
Capacity Factor	93% - 85%
Annualized Capital Cost	= (Instant Plant Cost)(Fixed Charge Rate)(Plant Capacity)
	= (553-803 $/kW)(0.15)(220 MW)
	= $18.25 - $26.50 Million

[15] According the Commission's Draft *Energy Technology Status Report* (ETSR), March 1996, the availability of a combined cycle plant will vary from year to year because the maintenance outage time varies from year to year. Base-loaded combined cycles have maintenance cycles of three to six years that requires an outage ranging from 20 to 130 days. The impact of maintenance outages on availability over a six-year cycle would be 1.8 to 5.9 percent. Forced outage rates are relatively low, generally ranging from 0.5 to 4.0 percent. For planning purposes a 2 percent forced outage rate is recommended in the ETSR.

[16] Gas Turbine World 1997 Handbook, Vol. 18, p. 56.

[17] Due Diligence Database, Stone & Webster Engineering Corporation.

[18] The instant cost is also referred to as the "overnight" costs because it assumes that plant is built overnight as opposed to the installed cost which incorporates inflation and interest payments incurred during construction.

[19] Based on a compilation of historical costs and estimates for combined cycle projects in the United States by Stone & Webster for the Commission's ETSR, Draft, March 1996.

[20] Stone & Webster has reported in its work for the Commission's Energy Technology Status Report (ETSR) that the information it has gathered on independent power producer projects across the country have total project costs of $834 to $1,981 per kW (1998 dollars). These estimates would be equivalent to the plant's ***installed cost***.

MWh of Generation	= (Capacity Factor x Capacity x 8,760 hrs) = 1,792,296 - 1,638,120 MWh
Capital Cost Recovery Rate	= (Annual Operating Cost/MWh of Generation) = \$10.18/MWh - \$16.18/MWh
Variable Fuel O&M Cost	= (Heat Rate x Gas Price) = \$13.86/MWh - \$18.00/MWh
Fixed Non-fuel O&M Recovery Rate	= (\$22/kW-yr x Plant Capacity)/MWh of Generation = \$2.70/MWh - \$2.95/MWh
MCP Needed for New Entrant	= (Capital Cost RR + Variable Fuel O&M + Fixed + Variable Non-fuel O&M) = (\$28.54/MWh - \$38.93/MWh)

These calculations show that the MCP needed to cover the cost of a new entrant encompasses a wide range. The prevailing optimism among investors is that a new combined cycle plant can be built at the $28 per MWh figure based on 1998 gas prices. There are claims of installed costs as low as $500 per kW and fixed O&M costs as low as $1 per MWh. Staff feels that investors may be too optimistic about the plant's likely capacity factor and the actual costs. The amount of must-run generation in California will exacerbate problems of over-generation, especially during minimum load conditions. This means that a new entrant's expectation of a high capacity factor may not be met. Based on construction cost estimates contained within the Applications for Certification filed by applicants at the Energy Commission seeking approval for siting new gas-fired combined cycle units, $34/MWh appears to be a more reasonable estimate of annual average revenue needed to sustain a new entrant.

Nevertheless, Staff acknowledges what appears to be a very persistent perception that new investments will occur based on the belief that a MCP of $28/MWh (1998$) is sufficient. Looking at the impact of competition on lowering operating costs in other deregulated industries, and recognizing that there are other revenue opportunities outside of the PX energy market, Staff accepts the $28/MWh estimate as plausible and defers to this estimate in developing its MCP Forecast.