Attachment A

CALIFORNIA ISO

Department of Market Analysis
P.O. Box 639014
Folsom, CA 95630-9014

Price Cap Policy for Summer 2000

Prepared by the
Department of Market Analysis
California ISO

March 2000

Table of Contents

1. Executive Summary

1.1 Purpose of this report

The primary purpose of this Report is to assess whether the structural features of the California electricity markets promote workable competition. The ISO Governing Board requested this assessment be made as part of their determination of the appropriate level of price caps in the ISO markets for Summer 2000.

In addition, this Report looks beyond Summer 2000 and provides some longer-term price cap policy options.

1.2 Summary of DMA recommendations

> *The DMA recommends that the Board maintain price caps at the $750 level for Summer 2000.*

Given that price cap authority expires on November 15, 2000, the DMA recommends that the ISO initiate a stakeholder process to consider alternatives to price caps for the long-term. The precise design of a price cap policy for the post-November period should be developed using Summer 2000 experience and in coordination with congestion management reform. This may require requesting a limited extension of the current price cap authority to provide protection against market power abuse. The extension would allow the ISO to review the Summer 2000 experience and develop effective permanent measures to mitigate market power that are integrated with congestion management reforms. The ISO will be reviewing the merits of requesting a price cap extension and discussing other options with stakeholders and anticipates requesting some type of Board action on this issue in April 2000.

The remainder of this Executive Summary provides the rationale for the $750 price cap recommendation, as well as a brief overview of price cap policy options for implementation after Summer 2000.

1.3 Findings and recommendation for Summer 2000

The Board's August 1999 resolution on price caps identified three criteria to be evaluated in March 2000, and specified that the level of prices caps for Summer 2000 should either stay at $750 or be lowered to $500, effective June 1, if the Board determines that: (1) the markets are not workably competitive; (2) there are not practicable demand side management options in place; or (3) the IOU Utility Distribution Companies have sought and not obtained practicable options to self-provide ancillary services and applicable hedging products in the Power Exchange consistent with the California Public Utilities Commission Preferred Policy Decisions.

To summarize our assessment of these three criteria, the DMA believes that progress in these areas has been meaningful. That is, the risks of uneconomic price spikes are reduced in comparison to the market structure of one year ago, but the risks have not yet been eliminated. Our findings are summarized below, with greater detail in subsequent sections of this Report.

Regarding the following criterion —

1) *While the markets are workably competitive during most hours, there is clearly market power during hours in which system loads are the highest. Historical prices suggest that market power is most significant when ISO system loads exceed 40GW. This occurred in 121 hours in 1998 (approximately 1.4% of the total hours per year) and in 57 hours in 1999 (less than 1% of the total hour per year]. In these hours, individual suppliers run little or no risk of not being called if their bid prices are too high, and thus there is no constraint on how high they might raise their prices in the absence of price caps. On the one hand, the need to call upon all suppliers at extremely high load levels is not a problem we can expect to go away. The restructured industry is not likely to overbuild capacity to the extent that we can depend on an abundance of competitive supply at even the highest peak hours. Nor can we ever expect, given the capital-intensive nature of this industry, to have textbook "perfect competition" with large numbers of competing suppliers who are all price takers. Rather, ownership of resources is likely to remain fairly concentrated among a small number of suppliers. In addition, some degree of locational market power will probably be a permanent feature of competitive electricity markets, deriving from the configuration of the network, the varying capacities of transmission facilities, the locations of resources, the patterns of energy flows, and the inevitability of outages and derates at various times. We return to these considerations later in discussing policy options for the post-Summer 2000 period.*

   One of the main ways buyers can mitigate market power is through price responsive demand. Right now the degree of workable competition is limited by the fact that most end-use load is subject to the rate freeze and has no incentive to reduce consumption in response to high prices. The AB 1890 rate freeze that insulates end-use customers from high hourly prices will come to an end, perhaps before Summer 2001. Once this artificial constraint is eliminated and load can respond, those suppliers who try to bid high prices will risk reduced sales volumes and reduced profits. This is, fundamentally, how greater demand responsiveness reduces the ability of suppliers to exercise market power.

For Summer 2000, the UDCs and the ISO have developed several new programs for facilitating load price responsiveness. While these programs are relatively small in scale compared to the level of demand responsiveness that may be possible under a long-term, post rate freeze environment, they do provide an opportunity to develop more price responsive demand than existed last year. In addition, the CalPX has expanded its block forward market to include a number of new energy and ancillary service products. These new products provide new opportunities for UDC's to hedge against high energy and ancillary service prices in the day-ahead market.

In summary, this report provides empirical evidence indicating that in 1999, markets were workably competitive in most hours but market power persisted during periods of high peak loads. DMA believes similar conditions will exist for Summer 2000. However, new load responsiveness programs and hedging products will provide new opportunities for load service providers to mitigate and hedge against market power.

2) *Addressed in 3.*

3)

4) *The new programs being established for Summer 2000 — for load curtailment, load participation in the ISO markets, and hedging for energy and ancillary services through the PX — will be helpful in mitigating high prices. This Report provides descriptions of these programs and their potential impact on the markets. Though these programs are relatively small in scale, we believe that, collectively, they provide load providers with significantly more opportunity to protect against high prices than was available last summer. The new UDC demand responsiveness programs and the ISO's Summer 2000 trial program for load participation will provide new opportunities for load to respond to market prices, which will help to mitigate market power. The hedging programs that are either currently in place or will be available by May 2000 in the CalPX are in the form of block forward market futures contracts for energy and ancillary services. These products provide UDCs with an opportunity to hedge some of their load and ancillary service obligations against high prices in the day-ahead market.*

While these three criteria are important considerations, DMA believes there are additional criteria that the Board should consider in making its decision. When these additional criteria are viewed in combination with the improvements achieved on the first three, we believe they tip the balance in favor of leaving the caps at $750 for Summer 2000. These other criteria are:

5) The adequacy of import supply to the ISO system during peak hours of Summer 2000. *Given the likelihood that we will have a hotter* *summer than 1999, we need to consider the possibility of coincident peaks occurring in the Southwestern region, forcing the ISO to compete for supply with neighboring control areas. In such situations the $750 cap will be more effective than the $500 cap in attracting supply to the California markets.*

6) *The need for empirical evidence on market performance at high load levels, in view of the impending expiration of price cap authority on November 15. Such evidence will be critical for assessing appropriate ISO policy to pursue after Summer 2000. (Later in this Report we discuss some of the options.) Unless the Board decides to do nothing and simply allow all price cap authority to expire, which we recommend against, it will be necessary to file at FERC for some form of mitigation. To support such a filing, the ISO should have the strongest possible evidence on how the markets will perform in the absence of binding price caps. The $750 cap level will allow more room for demand and supply to reach equilibrium, and thus will provide stronger evidence than the $500 level.*

7) The incentive effect of consistent long-term policy. *Although the Summer 2000 level of price caps may not directly affect the revenue expectations for potential investment in new capacity, it will send the market a signal about the ISO's long-term policy objective. The DMA believes it is important to provide strong incentives to the market for new investment in generating capacity, demand price responsiveness, and transmission capacity, and that maintaining the $750 level of price caps will demonstrate the ISO's commitment to the long-term policy objective of achieving a workably competitive market and eliminating dependence on price caps to mitigate market power.*

8)

9) A $750 cap will provide a greater incentive for participation in the load responsiveness programs developed for Summer 2000. *Greater participation in these programs will provide useful information on the extent to which different types of load will respond to market prices. This information will be very useful in developing future load participation programs and will also help the ISO in developing a market power mitigation policy after Summer 2000*

10) Potential impact of a lower price cap level on more rapid ending of CTC collection and the rate freeze. *While we agree with the logic of this effect, we do not expect its magnitude to be significant enough to make it a major factor in the Board's decision.*

11) Distributional effects of the price cap level. *Given the limited ability and incentives for load to respond to prices, the choice of a higher price cap level rather than a lower level will result in higher costs for loads and higher revenues for suppliers. This is predominately a*

distributional effect, a transfer from one side of the market to the other. The DMA does not have a recommendation on how the Board should weigh this item, as it is not an economic consideration.

Based on the factors discussed above, particularly criteria (1)-(7), the DMA recommends that the Board retain the $750 level of price caps on the ISO markets for Summer 2000.

1.4 Post-Summer 2000 options and recommendation

Looking toward the expiration of price cap authority on November 15, 2000, DMA is concerned that some impediments to workable competition remain. We recommend, therefore, that the Board begin now to consider the various policy options that would be effective in protecting the ISO markets against the exercise of market power beyond that date. Some such capability will be needed both on a temporary basis – i.e., until the ISO implements congestion management reforms as ordered by FERC and the 10-minute dispatch and settlement provisions, and the retail rate freeze comes to an end – and on a permanent basis to mitigate market power in certain instances where specific resources would be able to drive up the market clearing price or the payment they receive in a way that is not connected to meaningful investment incentives.

Without going into great detail on the options at this time, this section will just identify the main policy options the Board might pursue. These are:

- Do nothing. Allow all price cap authority to expire on November 15, 2000. For reasons noted above, the DMA recommends against this option.

- Apply to FERC for "safety net" authority only. The ISO could implement a safety net either in the form of a very high backstop price cap (in the range of $2,500 to $5,000, for example), or as a provision for discretionary authority of the CEO to act quickly to limit prices under extreme circumstances, with rapid follow-up consultation with the Board.

- Apply to FERC for more general authority that would allow the ISO to maintain a moderate level of price caps for a certain time period while certain remaining impediments to workable competition are being eliminated, at which time the ISO would retain only the safety net. The conditions for moving to the safety-net-only regime could include presently anticipated reforms to the ISO markets as well as external conditions, particularly the termination of the rate freeze and the CTC, which will impede demand responsiveness as long as they are in effect.

- Implement an alternative to market-wide price caps to mitigate market power in both the near term and the long term. For example, the Board could consider the mechanism used by the PJM ISO — an individual bid cap for each generator based on its costs, which would provide a basis for payment when that generator is called for local reliability or congestion mitigation, and there is no way to meet these needs through the competitive bid process.

- Some form of Price Volatility Limit. Although the Board and stakeholders considered such a mechanism and found them to be unnecessarily cumbersome, DMA would like to keep this as an alternative since it is a mechanism used in mature markets, and does provide a warning to demand to get ready for possible price spikes, thus introducing some demand elasticity into the market.

The DMA intends to explore these options further and will report to the Board at a later date on their pros and cons. We point out, however, that if the ISO were to file at FERC 60 days before the November 15 expiration date to extend its price cap authority, there would not be adequate time to fully assess Summer 2000 market performance and develop a policy recommendation based on that analysis. One option for the Board to consider is the possibility of filing for a limited extension, say to February 15, 2001, for the purpose of fully assessing Summer 2000 and developing a long-term approach in coordination with the congestion management reform process. Taking this approach, a long-term policy for market power mitigation could be filed as part of the congestion management reform filing in October, 2000. The ISO will be reviewing the merits of requesting a price cap extension and discussing other options with stakeholders and anticipates requesting some type of Board action on this issue in April 2000.

2. Background

In August 1999 the ISO Board of Governors passed a resolution that raised price caps on the ISO ancillary services and real time energy markets from the level of $250 (per MW of capacity or per MWh of energy) to $750, effective September 30, with the provision that the Board would reduce the cap to $500 effective June 1, 2000 if it determined that:

- the markets are not workably competitive,
- there are not practicable demand side management options in place, or
- the IOU Utility Distribution Companies have sought and not obtained practicable options to self-provide ancillary services and applicable hedging products in the Power Exchange consistent with California Public Utilities Commission Preferred Policy Decisions.

The same resolution also:

- directed ISO management to report to the Board no later than March 2000 on its review of whether any of the conditions above have been met;
- adopted a "safety net" provision whereby management would be authorized to lower price caps without Board action upon management's assessment that the affected market is not workably competitive, with follow-up notification and analysis to be presented to the Board;
- directed management, after completion of the summer of 2000, to analyze the results and recommend to the Board an implementation plan to eliminate price caps; and
- directed management to file the necessary Tariff language with FERC to implement the policy adopted in the resolution.

On September 17, 1999 ISO management filed Amendment 21 to the ISO Tariff to implement the policy adopted by the Board. Rather than asking FERC to approve the specific elements of the Board's adopted price cap policy, Amendment 21 followed the approach of previous filings and FERC rulings on price caps by simply asking for an extension of current price cap authority, which was due to expire on November 15, 1999, for one additional year. The ISO did, of course, fully describe the Board's resolution and explain the rationale behind it. On November 12, 1999 FERC issued an Order accepting Amendment 21, with the result that the ISO's present authority to impose price caps on its markets is now due to expire on November 15, 2000.

The ISO's filing of Amendment 21 provided the full rationale for the extension of price cap authority. The fact that (1) the effectiveness of the ancillary service market reforms to maintain competitive conditions had not been established through practical experience and that (2) RMR contracts have not yet been reformed in a manner consistent with the recommendations of the MSC and the MMC were two of the main reasons given for requesting an extension of price cap authority. In addition, it was also noted that entities serving demand were limited in their ability to protect against high prices through demand management and hedging products. Many of these points are still quite relevant for the present discussion of both the level of price caps for Summer 2000 and the options for Board policy subsequent to Summer 2000.

In the Order on Amendment 21 the Commission made an important clarification which bears reiterating for the present discussion, as it has implications for the ISO's ability to procure adequate supplies when its markets are subject to price caps. FERC noted that the "proposed cap is not a cap on what a *seller* of ancillary services may charge to the ISO but rather is a cap on what the ISO as *purchaser* is willing to pay [emphasis in original]. The ISO has no more, or less, discretion than any other buyer of services. If the ISO is unable to elicit sufficient supplies at or below its announced purchase price ceiling, it will have to raise its purchase price to the level necessary to meet its needs." Furthermore, "Intervenors' concerns about the ISO retaining excessive discretion are unsupported. Sellers of ancillary services and imbalance energy who are dissatisfied with the ISO's purchase price cap can choose instead to sell these services in the California Power Exchange or the bilateral markets. They are not required to sell to the ISO, and thus the ISO cannot dictate their prices." [Order at 9]

3. Assessment of Market Competitiveness

3.1 Review Summer 1998 and Summer 1999 energy and ancillary services market performance

By many measures, California's energy and ancillary service markets have improved significantly in 1999 compared to 1998. This success has been due in large part to the many market reforms the ISO has implemented, and because generation that was previously limited to FERC imposed cost-based bid caps for ancillary services was eligible for market based rates in 1999. Some of the more promising trends observed in 1999 include:

- Substantial increase in bid sufficiency in the ancillary service markets

- Substantial reductions in ancillary service costs both as a percent of energy costs and in $ per MW of load.

- Market prices for energy and ancillary services that are more reflective of the relative quality of each commodity (i.e., energy prices are generally higher than ancillary service prices, regulation prices are generally higher than spinning reserve prices etc.).

- Significant decreases in the number of price spikes in both the energy and ancillary services (Figure 1).

Though these trends are encouraging, they need to be tempered by the fact that California experienced a cool summer in 1999. Unlike 1998, there were no sustained periods of extremely high loads and simultaneous peak loads with the Southwest that would truly test the robustness of California's wholesale energy and ancillary service markets. Historical prices suggest that market power is most significant when ISO system loads exceed 40GW. This occurred in 121 hours in 1998 (approximately 1.4% of the total hours per year) and in 57 hours in 1999 (less than 1% of the total hour per year].

In those hours where high loads occurred in 1999, there was a strong tendency for prices to hit or approach the price cap. This is shown in Figures 2-4. Figure 2 shows, in columns, the frequency of system loads by GWs and also shows the corresponding average energy prices (in lines). This figure demonstrates that under high load conditions (i.e., loads greater than 40 GWh), the ISO's average real time energy price (NP15) increases toward the $250 price cap, and included in these averages are a number of incidences of prices at $250/MWh. The high prices can be compared with the system marginal cost of meeting the demand. It is shown that during these peak hours that the price is higher than the system marginal cost. This price cost mark-up analysis is contained in Borenstein, S., Bushnell, J.B., and F. Wolak (2000). "Diagnosing Market Power in California's Restructured Wholesale Electricity Market." The PX day-ahead unconstrained energy price follows a similar pattern, but rather than approaching the price cap, average PX prices tend to approach $150/MWh. In fact there is a very consistent divergence in the ISO's average real time energy price and the average PX day-ahead energy price when loads exceed 37 GWh. This difference is largely attributable to a tendency for loads to hedge against high energy prices in the PX by bidding price-responsive demand. Since there is very little "actual" price responsive demand, most demand that does not clear the PX market has to be met in the ISO's real time market. During peak-periods, load serving entities are able to lower their energy costs by bidding in a way that ensures most of their demand is met in the PX market at a price below $150/MWh, with the residual load being met in the ISO real time market at a price at or near $250/MWh.

Figure 1. Spikes When Price Hit Cap

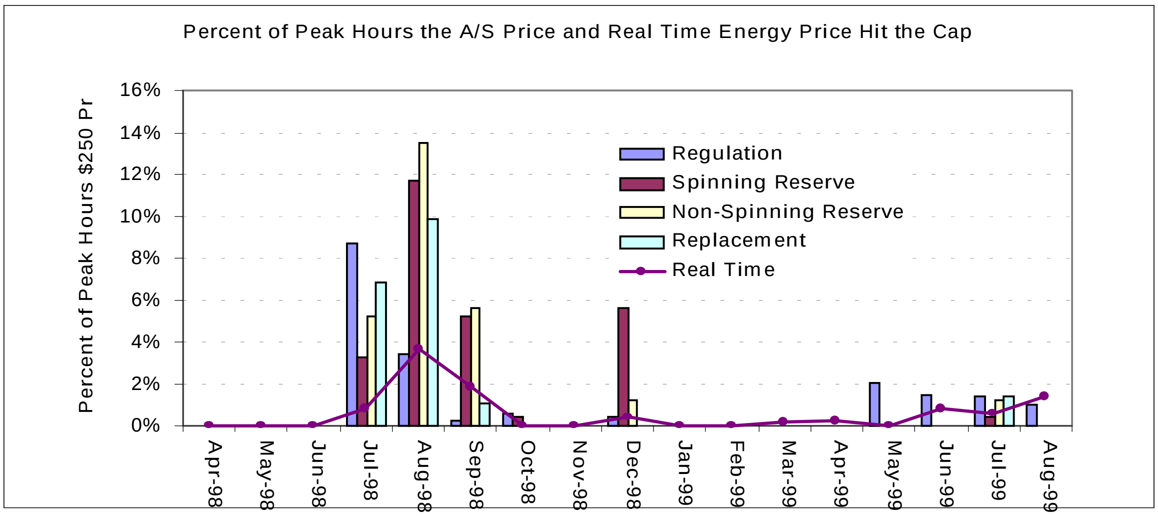


Figure 2. Total System Loads and Energy Prices

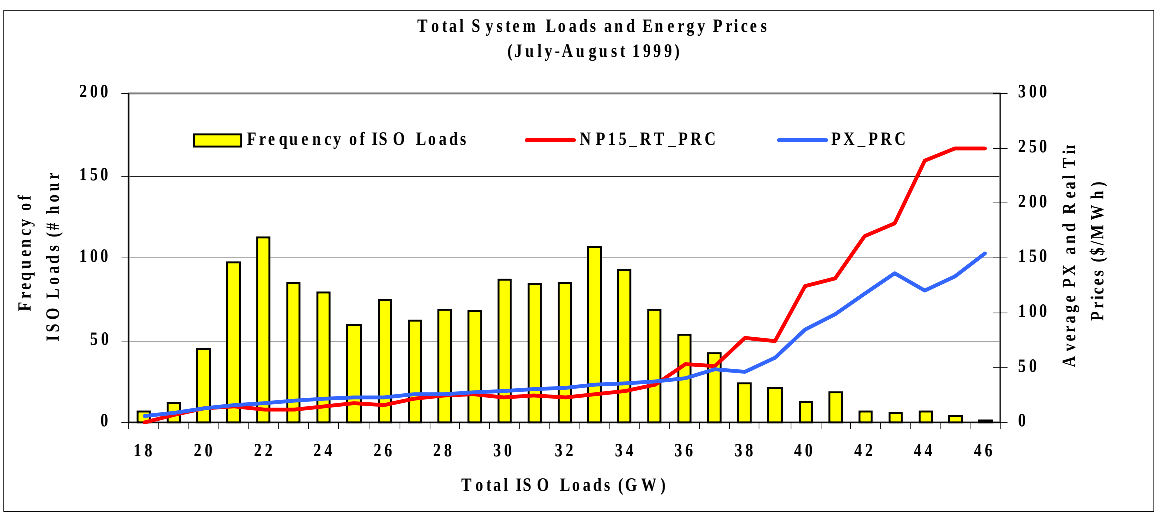


Figure 3 is a similar graph to Figure 2 but includes the average day-ahead capacity price of upward regulation. This figure demonstrates that price patterns in the ancillary service market are very similar to the energy market. Under high load conditions, average regulation prices increase significantly, and included in those averages are a number of prices at $250/MW.

Figure 3. Regulation and Energy Prices by Loads

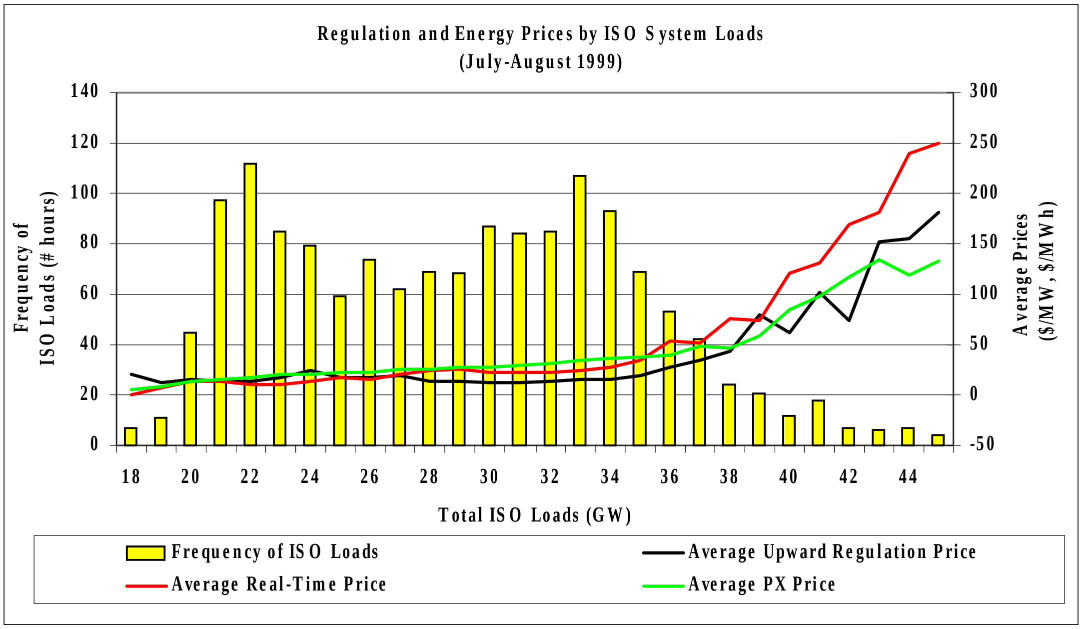
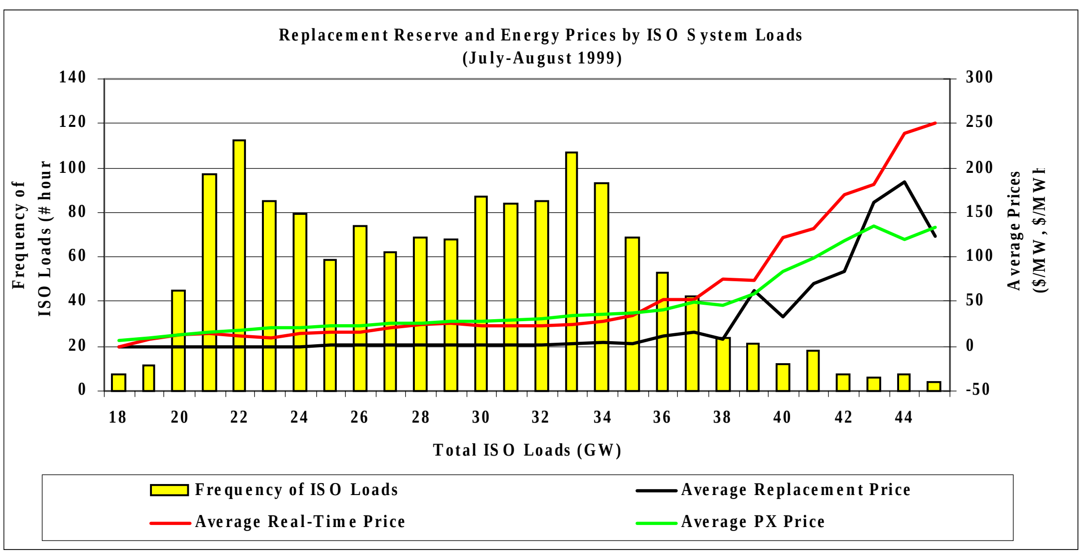


Figure 4 shows a similar trend for replacement reserves and though not show here, these same price patterns can be seen in all ancillary service markets.

Figure 4. Replacement Reserve and Energy Prices by Loads



In summary, while the ISO markets for energy and ancillary services have improved significantly since the ISO began operation in April 1998, some market power problems remain during periods of high demand. During these high demand periods, market prices tend to hit or approach the $250 cap.

3.2 Review DMA's assessment of market competitiveness

Overview

The classical economic definition of a workably competitive market is one in which a large number of firms compete to produce the same product and no firm is able to raise prices significantly above system marginal costs for a sustained time period. There is market power if there is the ability to raise prices significantly above system marginal costs, unimpeded by competition from other suppliers, other substitute products, or demand elasticity.

In a recent paper titled "Diagnosing Market Power in California's Restructured Wholesale Electricity Market"[1], the authors examine the degree of competition in the California wholesale electricity market during the period June 1998 to August 1999. The analysis compared actual market prices with estimates of what prices would have been had in-state fossil fueled generating units behaved as price takers. The study draws the following conclusions:

- There was little evidence of the exercise of market power during the winter and spring of 1999.
- The exercise of market power was most pronounced during periods of high demand (July – September).
- There was significantly less market power exercised during the summer of 1999 compared to the summer of 1998.
- The exercise of market power raised the cost of power purchases by about 13.9% above a competitive level.

In summary, these findings suggest that market power in California wholesale electricity markets is predominately exercised during high demand hours, and that there has been significantly less market power exercised in the summer months of 1999 compared to 1998.

A workably competitive market produces market prices, which are reasonably close to system marginal cost, i.e. the highest cost unit to serve the demand. So far there is no bright line rule from government regulatory agencies as to the

[1] Borenstein, S., Bushnell, J.B., and F. Wolak (2000). "Diagnosing Market Power in California's Restructured Wholesale Electricity Market."

exact threshold of allowable price-cost mark-up. Some analyses have used 5-10% % average price-cost mark-up over a calendar year as a warning line for significant market power. The MSC has recommended DMA use a comprehensive evaluation process, which involves examining a list of qualitative and quantitative indicators of workable competition. Included in this check list are:

Significant quantity bid into market above the current market-clearing price. Under these conditions, if a supplier were to raise its bid, the MCP would change very little if at all: The supplier's electricity (or capacity) would simply be replaced with electricity (or capacity) bid by others at or near the MCP.

Bids at or near marginal cost. The strongest single piece of evidence that a given supplier lacks market power is the observation that this supplier bids its energy and/or capacity into the market at or near its marginal cost. This price-cost mark-up has been done for the California energy markets but does not include an evaluation of the CAISO's ancillary service markets.

Supply is not concentrated. Although this is a common measure used in other industries, it is not the very best available measure of market power in California's electricity markets. This is because the electricity power market demand and supply conditions change from hour to hour, and no concentration measure is going to accurately measure the market power condition for all hours. With the same concentration index value, during the system peak load hours the market supply is very short and price-cost mark-up is very high and during off-peak hours, there is abundant supply and competition keeps the price very close to the system cost. To better measure a large supplier's market power, DMA has developed and applied the residual supply index, which assesses whether a large supplier is pivotal in any hour and be able to set excessive market clearing prices.

Buyers are Flexible. Market power by sellers is inevitably reduced if buyers have the flexibility to reduce their demand in the presence of high prices and/or to turn to other sources of supply (either a substitute product or the same product provided from a different geographic area). Promoting load responsiveness program in the long run will be key feature of a workably competitive market.

No Unnecessary Institutional Barriers to Rivalry or to Demand Flexibility. Generally speaking, an assessment of whether a market is "workably competitive" will include an evaluation of whether there are institutional features that reduce rivalry among actual and potential suppliers, or than hinder buyer flexibility. CPUC has move toward allowing greater hedging and demand response programs by investor owned utilities. As the rate freeze and CTC recovery end, there should be greater incentives for more load response and hedging.

Collusion is Difficult. If collusion is easily achieved, or at least a dangerous probability (e.g., because of a concentrated market structure or because the suppliers have ample opportunities to meet and reach illegal agreements), a market may fail to be “workably competitive.”

Entry into the Market is Easy. The final factor that should be considered in evaluating whether a market is “workably competitive” is the ease of entry into that market.

To ensure new entry and therefore adequate supply resources in the market, it is important to allow sufficient price incentive to attract new investment, out of state supply, transmission expansion as well as keeping the existing generation online. There have been extensive debate as to what is the proper balance between two seemingly conflicting goals: the need to keep price as close to system marginal cost as possible to promote competition and the need for high price incentive to attract enough resources to maintain system reliability. To address the issue of whether the current market price provide adequate incentive for supply resources and what impact the price cap levels may have on the incentives, DMA has conducted some additional analysis that uses historical prices to determine whether new generation would find it profitable to locate in California

3.3 New generation investment incentives

This section examines the economics of investment in new supply capacity at recent price levels (for the period from February 1999 through January 2000), as well as under potentially higher prices that could result from a combination of load growth (10% above 1999 levels) and higher price caps.

Two technologies are examined: a 500 MW combined cycle unit, and a 167 MW combustion turbines peaking unit. Table 1 summarizes key plant characteristics and financial assumptions used in the analysis. The operational and scheduling assumptions used for each unit are summarized below:

- Combined Cycle. The unit is assumed to be scheduled at full capacity in the Day Ahead PX market if the PX price exceeds the units variable operating cost at full load. During hours when the PX price is lower than the unit's variable operating costs, it is assumed the unit is scheduled at a minimum level of 140 MW in the Day Ahead PX market, and acts as a price-taker in the Ancillary Services markets (i.e. the unit sells 50 MW of spinning reserve and 250 MW of replacement reserve at the MCP). Additional potential revenues from sales of energy in the real time market when the unit is providing Ancillary Services are calculated, but were found to have a minimal effect on overall annual net revenues.[2] A combined forced and planned outage rate of 5% is represented by decreasing total annual net operating revenues by this amount.

- Combustion Turbine Peaker. The unit is assumed to not be scheduled in the Day Ahead PX market, and instead acts as a price-taker in the market (i.e. each hour the unit sells 167 MW of replacement reserve at the MCP). The unit then supplies energy in the real time price when the real time prices exceeds the unit's variable operating costs plus a $4/MW adder to reflect the need to recover start-up costs in the event the real-time price rises above the unit's variable operating cost for only one or two hours. A real time energy "dispatch factor" of .9 is applied to the unit's capacity to reflect the assumption that the unit would not always be dispatched even though the ex post price exceeded its variable costs. A combined forced and planned outage rate of 5% is represented by decreasing total annual net operating revenues by this amount.

The base case analysis was performed using actual 1999 price data (from February 1999 through January 2000) for the PX Day Ahead energy, Ancillary Services and Real Time energy markets. The price scenarios for price cap levels of $500 and $750 were developed using the same methodology used in Section 3.4 of this report to estimate lower bound potential price impacts of different

[2] The startup decision is based on a seven day look-ahead of revenues in the PX market: if projected net revenues exceed costs, it is assumed the unit is started up. The unit continues to operate as long as any losses incurred over a period of up to three days do not exceed the cost to restart the unit.

price cap levels of total market energy costs. Gas prices were based on average monthly city gate prices for the same period, which average about $2.70 over this period.

Table 1. Generating Unit Assumptions

	Combined Cycle	Combustion Turbine Peaking Unit
Maximum Capacity (MW)	500	167
Minimum Operating Level (MW)	140	n/a
Heat Rates (MBTU/kW)		
Maximum Capacity	7,200	10,500
Minimum Operating Level	8,200	n/a
Installed Capacity Costs ($/kW)	$450 - $550	$375 - $425
Fixed Annual O&M ($/kW-yr)	$10	$7.50
Variable O&M	$2/MWh	$3.50/MWh
Startup Costs ($/start)	$2,500	$1,000

NOTE: Range of values for installed capacity costs indicate low and high values used in sensitivity analysis.

Summary results of this analysis are presented in Table 2. Three indicators of the economics of investment under each scenario are provided:

- Internal-Rate-of-Return (IRR) on the total installed capital costs over a 20 year period.
- Return on Equity (ROE), assuming 50% of the cost of new supply investments is financed at 9% over a 20 year period.
- Net Variable Operating Revenues ($/kW of installed capacity), or revenues less variable fuel and O&M costs. This provides a measure of revenues that may be directly compared to estimates of revenue requirements (fixed annual O&M plus capital recovery).

Key trends illustrated by results presented in Table 2 are summarized below:

- Given prices over recent 12 month period used in this analysis, both types of units would appear to be financially attractive in NP15, but marginal in SP15, due to the lower prices that prevailed in SP15 over the past 12 months. Although the overall price level in SP15 is not as high as in NP15, there are local areas where supply cost is higher and the effective price is higher. The potentially higher price is either reflected as RMR payment or in the form of higher zonal prices if new zones are created in these areas. For these areas where new investment is really needed, the incentive should be adequate for new generation investment.

- The potential increase in prices due to raising of the price caps to either $500 or $750 (combined with higher prices due to load growth) could have a significant impact on the financial attractiveness of new supply in both NP15 and SP15.

- In SP15, investments in new supply appear to become financially attractive at the higher price scenarios used in this analysis.

In summary, this analysis shows a price cap of $750 should be sufficient to attract new investment into California. The price cap at $750 should also help to keep existing units profitable in covering their going forward fixed cost. The continued service from existing unit and the new generation investment will be critical in meeting the growing load in California.

Table 2. Financial Analysis of New Supply Investment

	Combined Cycle			Combustion Turbine Peaking Unit		
	IRR	**ROE**	**NVOR ($/kW)**	**IRR**	**ROE**	**NVOR ($/kW)**
NP15 Prices						
Low Installed Costs						
1999 Prices	16%	22%	$86	20%	31%	$82
$500 Cap	18%	25%	$92	22%	33	$86
$700 Cap	18%	27%	$96	23%	35	$89
High Installed Costs						
1999 Prices	12%	16%	$86	18%	26%	$82
$500 Cap	14%	18%	$92	19%	28%	$86
$700 Cap	15%	20%	$96	20%	30%	$89
SP15 Prices						
Low Installed Costs						
1999 Prices	10%	11%	$63	13%	17%	$59
$500 Cap	12%	14%	$69	14%	19%	$62
$700 Cap	13%	16%	$72	15%	21%	$65
High Installed Costs						
1999 Prices	7%	5%	$63	11%	14%	$59
$500 Cap	<9%	8%	$69	12%	15%	$62
$700 Cap	>9%	10%	$72	13%	17%	$65

NOTES:
Low Installed Costs = $450/kw for combined cycle unit, and $375 for combustion turbine.
High Installed Costs = $550/kw for combined cycle unit, and $425 for combustion turbine.
IRR = Internal rate-of-return on invested capital over 20 years. Range of values represents IRR with low price impact scenario (with 10% load growth over 1999).
ROE = Return on equity, assuming 50% of project financed at 9%. Range of values represents IRR with low price impact scenario (with 10% load growth over 1999)
NVOR = Net Variable Operating Revenues = Revenues minus variable costs (fuel and variable O&M) per kW of installed capacity.

3.4 Potential impact of price cap level on annual energy costs

Leaving the price cap at $750 for Summer 2000 likely will lead to higher annual energy costs than would be incurred if the price cap were lowered to $500. This section provides some estimates of this potential cost. A range of cost impacts are provided based on different assumptions about load conditions and pricing patterns. It is important to note, that a projection of this type requires assumptions about load growth and the likelihood of hitting price caps. While historical data are used to develop these assumptions, we cannot predict with a high degree of certainty what the actual impact will be. Only actual experience will bear that out. However, we do believe these estimates provided a reasonable bound of what the likely impact will be.

3.4.1 Review of Experience with $750 Price Cap

Reviewing price spikes that have already occurred under a $750 price cap provides a limited indication of how markets may perform under higher price cap levels. The ISO's real time energy and ancillary services price cap was raised to $750 on October 1, 1999, following the ISO's second summer of operation. However, in October and early November a series of price spikes occurred due to a combination of unseasonably high loads, decreased hydro supplies, planned and unplanned outages of a significant amount of other supply capacity, and de-rates of transmission capacity into Northern California.

Figures 5 and 6 compare prices in the ISO real time market and the PX day ahead market over the period from October 1 to November 9, 1999, when a series of price spikes above the previous $250 cap occurred in both these markets. Real time energy prices reached or exceeded the $250 level 22 hours in NP15 (Figure 5 1) and just three times in SP15 (Figure 6 2) over this time period. Prices in the PX market hit $725 and $250 during multiple hours on October 1, when, on the first day of the new price caps, transmission capacity into NP15 was limited.

Following price spikes of October 1, more defensive bidding of demand in the PX market kept prices below $150 in the PX day ahead market thereafter. However, the ISO's real time energy prices for NP15 and SP15 rose above $150 about 50 hours during this five-week period. Higher prices in the ISO real time market were due in part to the under-scheduling of loads in the day ahead PX market, which resulted in more demand having to be met in the real time market.

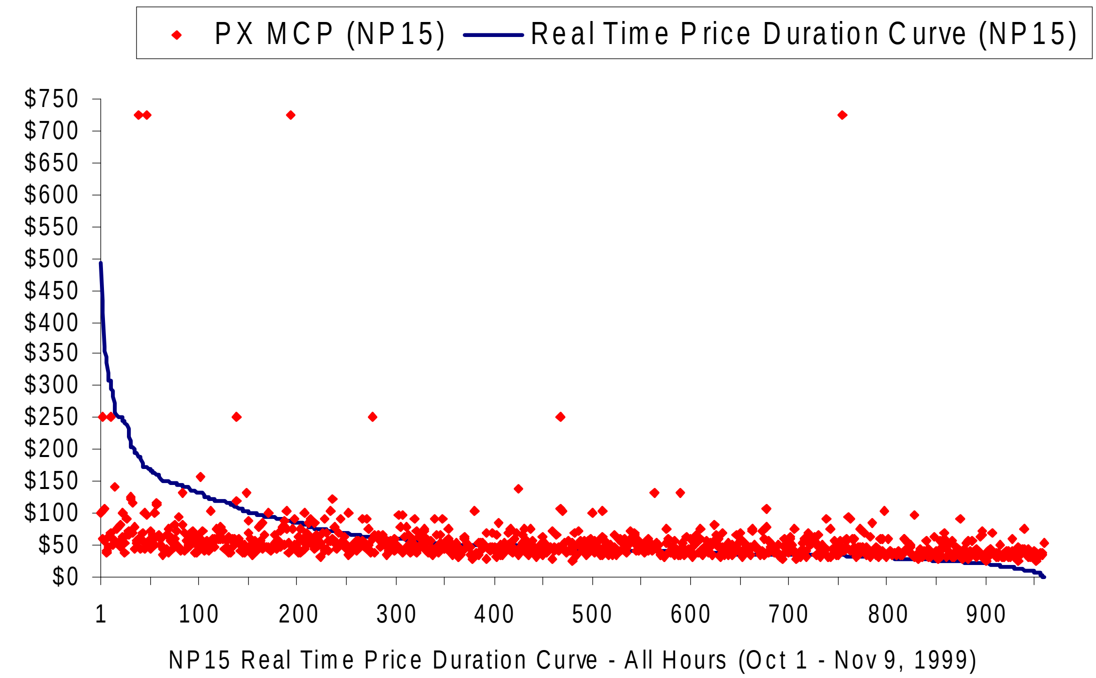
Although this period represents very limited experience of market performance with the $750 price cap, market performance over this five-week period highlights two possible trends that might be expected under higher price caps:

- Buyers in the day ahead market may respond to high prices by shifting larger portions of demand into the real time market when prices rise above the $150 to $250 level.

- When prices in the real time market exceed the $250 level, some degree of competition existed which prevented prices from simply rising from $250 to the new cap of $750. Instead, during these hours prices ranges from $250 to $500.

Both of these observed trends are incorporated into one of the methodologies (*low price scenario*) developed to assess the potential annualized impact of leaving the price cap at $750 versus lowering it to $500.

Figure 5. Real Time and PX Prices in NP 15 under $750 Price Cap (Oct1 – Nov 9, 1999)



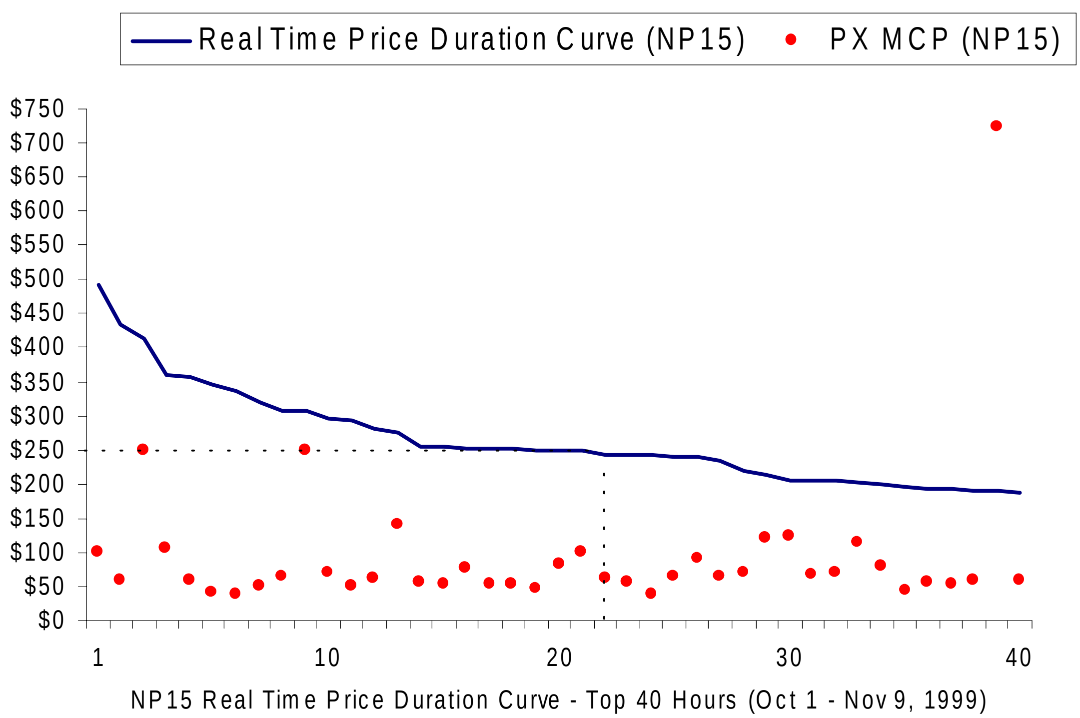
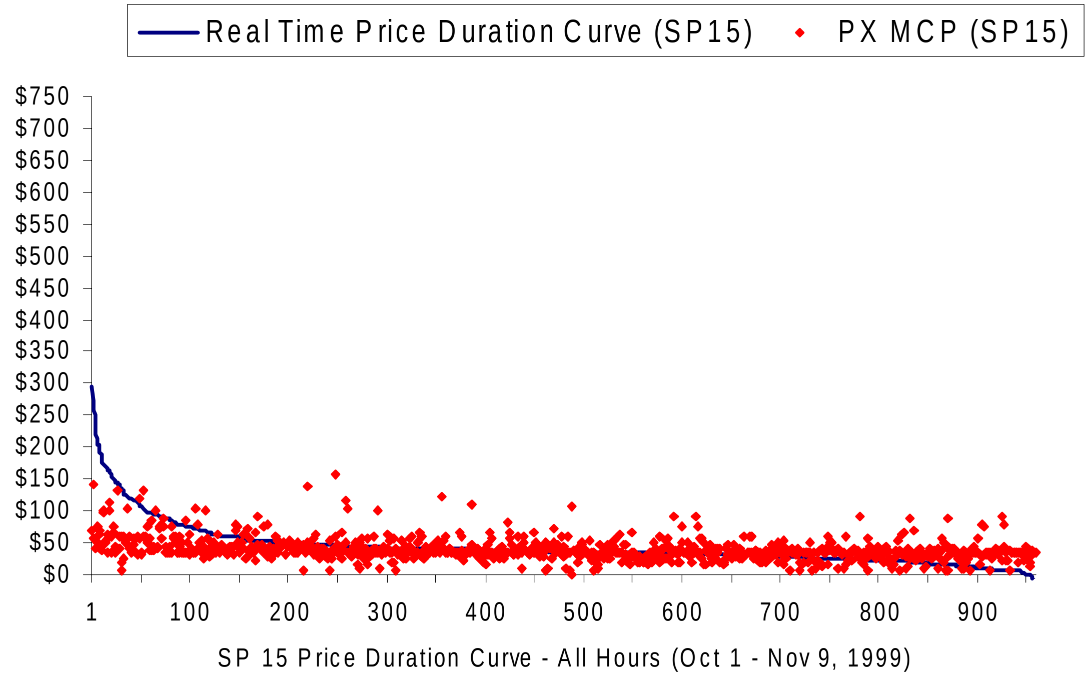
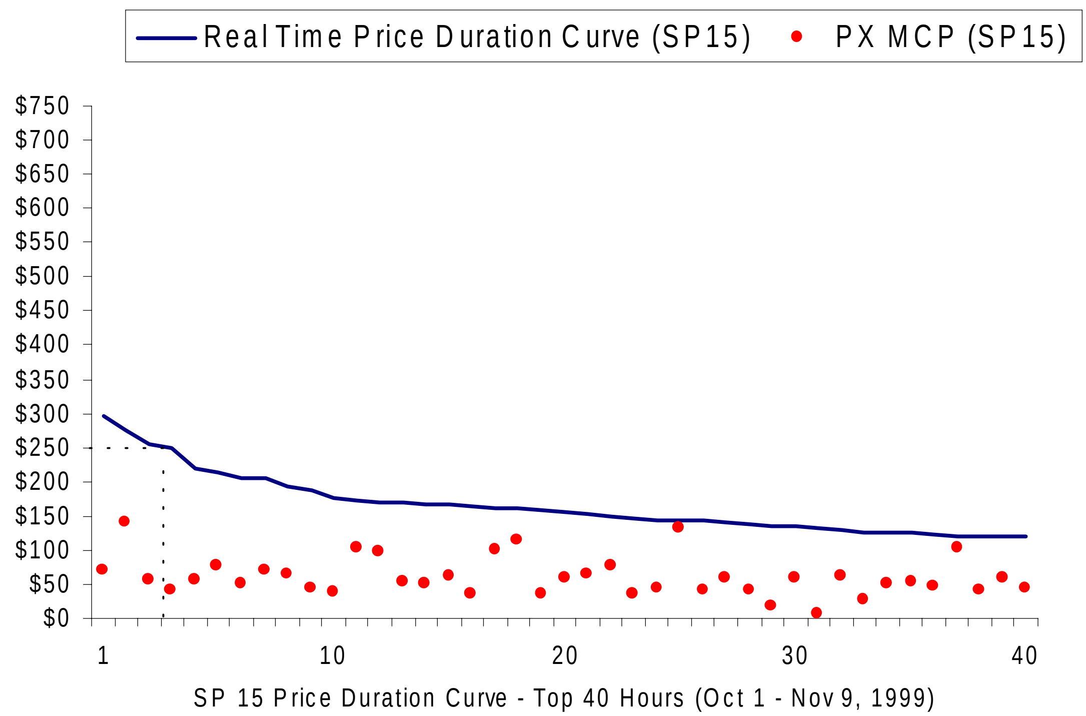


Figure 6. Real Time and PX Prices in SP15 under $750 Price Cap (Oct1 – Nov 9, 1999)





3.4.2 Assessing the potential impact of price cap levels on annual energy costs.

The potential impact of a price cap of either $500 or $750 was assessed using the four-step approach summarized below and is described in more detail in following sections of the report:

1. *Estimate potential impacts of higher price caps of $500 and $750 on real time using both high and low case scenarios that reflect the range of uncertainty surrounding the impact of higher price caps on 1999 price levels.*[3] The high price scenario assumes that for hours when the real time price reached the $250 cap, real time prices would hit the new $500 or $750 price cap instead. The low price scenario assumes that for hours when the real time price reached the $250 cap, real time energy prices would be distributed between $250 and the new price level of $500 or $750 price cap.

2. *Estimate the indirect impacts of higher real time price caps on prices in the forward markets (such as the PX day ahead market).* In this stage of the analysis, it is assumed that higher real time prices have the indirect effect of increasing average PX prices during high load hours. The analysis assumes that average PX prices for hours where loads are above 36,000 MW increase, due to higher price caps, by the same proportion as average real time market prices, subject to a maximum projected PX price of $300/MWh.

3. *Estimate the total impact of higher price caps on total energy costs in both the real time and forward markets.* In this step, the total cost impact of higher energy prices is estimated by multiplying price estimates for the real time and PX markets by the "net" loads in the real time and forward energy markets.[4]

4. *Estimate the total energy price and cost impacts under different demand scenarios.* Two different load scenarios are examined. The two scenarios use actual hourly loads over a 12-month period covering the 1998 summer months plus a 5% growth factor (representing above average weather conditions) and 1999 summer months plus a 5% growth factor (representing below average weather conditions).

[3] In this stage of the analysis, real time prices are projected by adjusting actual prices observed over the recent 12-month period from February 1, 1999 to January 31, 2000. The impact of higher loads on future prices is addressed as part of the final step of the analysis (Step 4).

[4] The quantity of energy met at the real time price is assumed to be the difference between the final hour ahead net load schedules and net actual loads. The quantity met at the PX price is assumed to be equal to the net hour ahead schedule. Net loads are equal to gross loads less generation provided from the UDCs. Net loads reflect the UDC's net position in purchasing energy. All calculations were performed using zonal prices and quantities for SP15 and NP15.

Step 1: Estimate Real Time Market Prices Under $500 and $750 Price Cap

Projected price curves for the real time market under a $500 or $750 price cap were developed by taking the most recent 12 months of data available (February 1, 1999 to January 31, 2000) and adjusting hourly prices during hours when the $250 price cap was reached. Two projected price curves were developed; a high price scenario and a low price scenario. A high price scenario was developed by simply replacing real prices at or near $250, with prices at the new price cap of $500 or $750.[5] A low price scenario was developed by assuming a distribution of prices between the $250 level and the new price cap level of $500 or $750. This scenario assumes that some degree of competition would exist during these hours that would, in some cases, prevent prices from reaching the new price cap. The basic curves used to estimate these price distributions were developed based on the very limited number of hours in October and November 1999 after the price cap was raised to $750, and real time prices reached or exceeded the previous cap of $250 (see Figure 7).

Figure 8 shows how historical hourly price data for the 1999 period were adjusted using the price distribution curves to develop the low price scenario used in this analysis. The price distribution shown in Figure 8, used to estimate prices during hours when historical prices reached the $250 cap, was applied after first sorting hours based on total system loads, so that the higher priced real time energy were estimated to occur during the hours when total system loads were higher. Also, a slight adjustment in the price duration curves was made to reflect the assumption that the new price cap of $500 or $750 would be reached in each of the four highest loads hours (when loads exceeded 45,000 MW).

After the impact of a higher price cap on real time price during individual hours was calculated, the average real time price (for all hours) for different load levels was calculated. For this analysis, hours were first categorized into different load level categories covering 1,000-MW intervals (e.g., 35-36GW, 36-37 GW, 37-38 GW, etc.). Average real time prices were then calculated for each of these load levels under each scenario.[6]

5 All ex post real time prices over $248 were considered cases in which the $250 price cap was reached.

6 All PX and real time price impacts were calculated based on a weighted average of zonal prices (NP15 and SP15). PX prices were assumed to apply to the amount of net-load in the final hour ahead schedules, and the real time prices were applied to the difference between actual net-load loads and the hour ahead net-load schedules.

Figure 7. Estimated Price Distributions

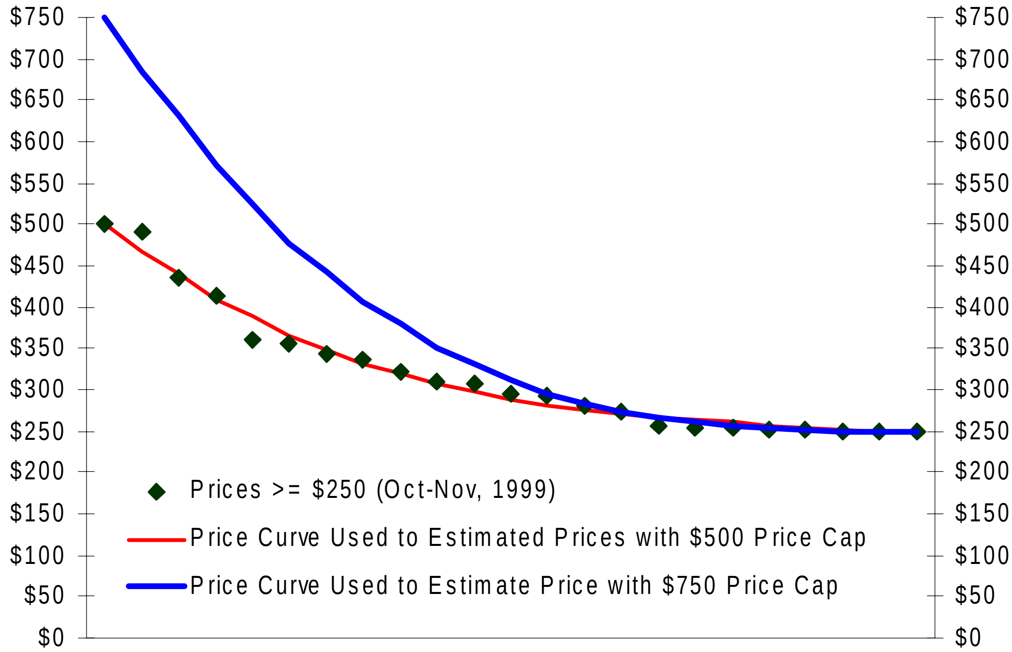
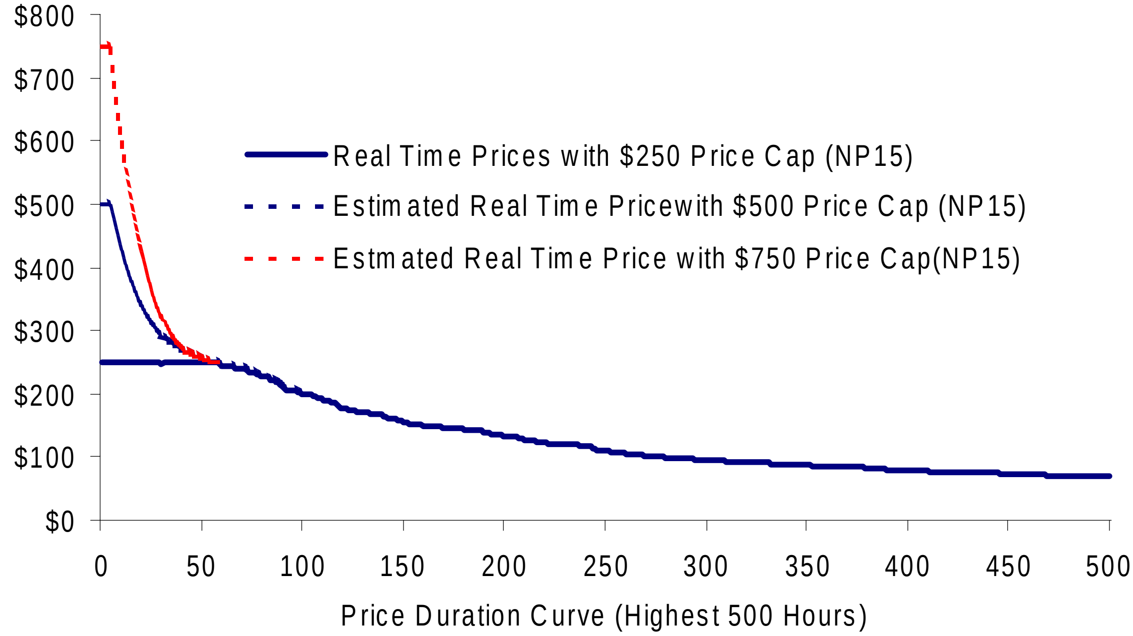
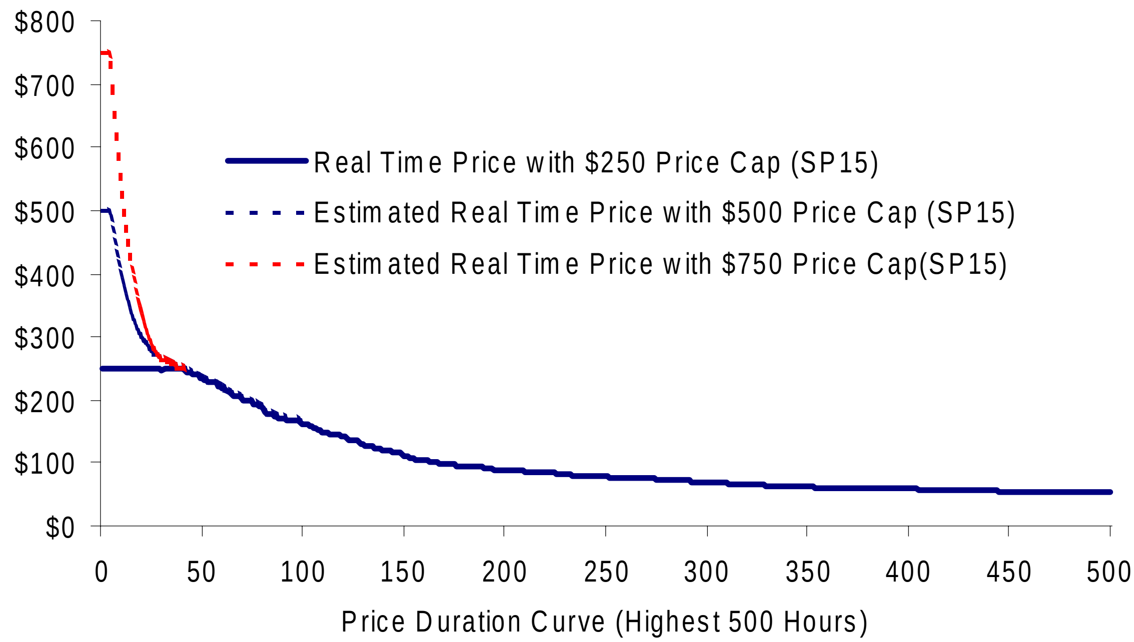


Figure 8. Price Distribution Curves for Low Price Scenario

Historical and Adjusted Price Curves (NP15)



Historical and Adjusted Price Curves (SP15)



Step 2: Indirect Effect on Energy Prices in Forward Markets

The increase in forward market energy prices was then estimated based on percentage increase in average real time price at each load level category under the different price scenarios described above, subject to a maximum limit on projected PX prices of $300/MWh.

For instance, if the estimated impact of higher real time prices increased the average real time prices by 50% during hours when system loads were between 40-41GW, then the projected average PX price during hours when system loads were between 40-41GW would be the minimum of 150% of the actual average PX price for that load category or $300/MWh[7].

Day ahead PX prices were used as the best proxy for prices in all forward markets and bilateral transactions that are scheduled in the day ahead market.

Step 3. Impact on Total Energy Costs

Average total costs at each load level (GW) were first estimated for each load level category as follows:

$$\textit{Average Total Cost}_{GW} = (\textit{Avg. PX Price}_{GW} \times \textit{Avg. HA Net Schedule MW}_{GW}) + (\textit{Avg. Real Time Price}_{GW} \times \textit{Avg. Real Time Net Quantity}_{GW})$$

The load quantities used to calculate Average Total Cost$_{GW}$ are "netted" from any generation supplied to the market by load providers (i.e., since both generation and load are subject to the market prices, only a load providers "net-load position" is impacted by the price cap.

Total annualized costs were estimated by multiplying average costs at each load level by the number of hours at each load level over the 12 month demand scenarios used in the analysis, and summing up total costs for the entire 12 month period.

$$\textit{Total Annualized Cost}_{GW} = \sum \textit{Average Total Cost}_{GW} \times \textit{Hours of Load}_{GW}$$

As described above, the methodology used in this study is designed to estimate total annualized system energy costs based on (1) average prices at different load level categories (e.g., 35-36GW, 36-37 GW, 37-38 GW, etc.), and (2) the number of hours in each load level over a 12-month period. This approach allows the impact of higher loads to be quickly assessed by modifying the number of hours during which system loads would reach each load level.

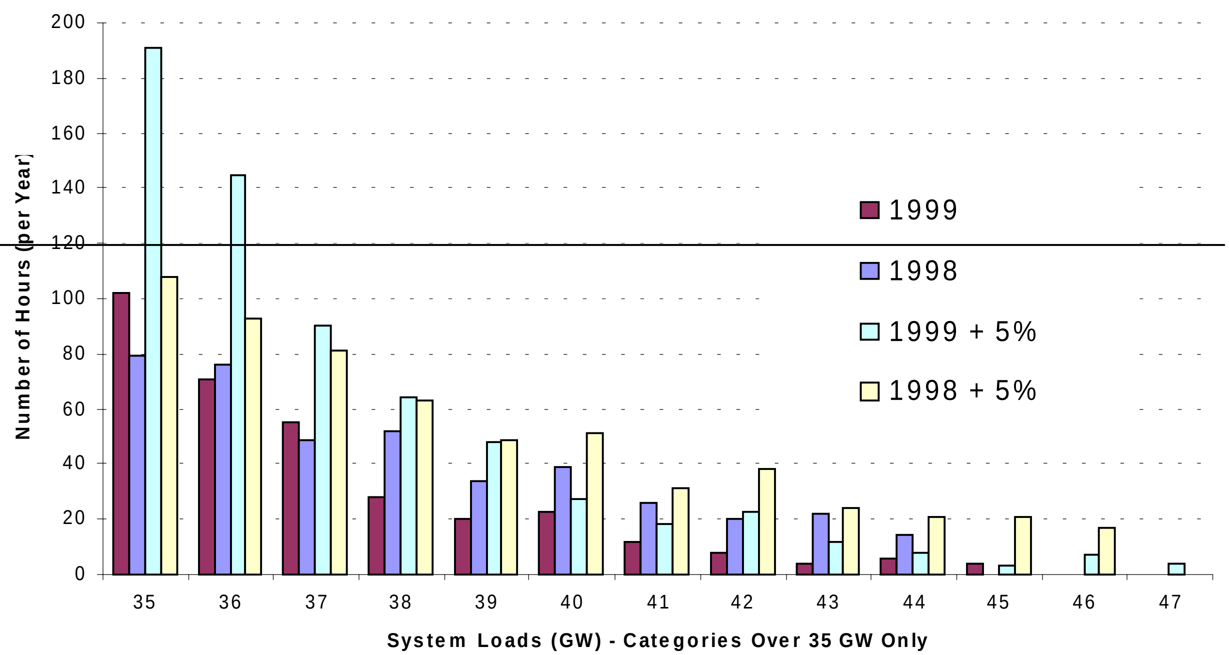
[7] Historically loads have been able to hedge against high prices in the PX market by bidding price responsive demand into that market. In doing so, demand that does not clear in the PX market is met by the ISO real-time imbalance market. During extreme peak periods, this practice typically results in ISO real-time prices at or near the $250/MWh cap and PX day-ahead prices under $150/MWh. This analysis assumes that under high price caps, this hedging strategy would be effective in keeping PX prices below $300/MWh.

To assess cost impacts under different load conditions, two different load scenarios are examined. The two scenarios utilize actual hourly loads over 12-months periods covering the 1998 summer months plus a 5% growth factor (representing above average weather conditions) and 1999 summer months plus a 5% growth factor (representing below average weather conditions). Table 3 summarizes each two load scenarios used in the study in terms of the scenario name used in this report, as well as the 12-month period (and any assumptions about load growth) that were used to estimate the number of hours at each load level. Figure 9 compares each load scenario in terms of the number of hours at each load level over 35,000 MW that would occur. As shown in Figure 9, applying a 5% growth factor increases the number of hours at high load levels and creates hours at unprecedented levels over 46,000 to 47,000 MW.

Table 3. Description of Different Load Scenarios

Scenario Name	12-Month Period (and growth assumptions)
Summer 1999 (plus 5%)	June 1998 - May 1999 (plus 5%)
Summer 1998 (plus 5%)	Feb 1999 - Jan 2000 (plus 5%)

Figure 9. **Frequency of High Load Levels under Different Load Scenarios**



Study Results

Table 4 summarizes the cost impact to the ISO real-time market, from different price cap levels, under each of the scenarios examined in this study[8]. Under the assumption of a 5% increase in 1999 summer loads (below average load conditions), the incremental energy costs in the real-time market from leaving the price cap at $750 versus lowering it to $500 range from $31 to $56 million. Under a high load scenario, in which loads grew 5% above summer 1998 levels, the total difference in energy cost in the ISO's real-time market may range from $79 to $117 million. In summary, a likely bound in the costs impact to the ISO real-time market from leaving the price cap at $750 versus lowering it to $500 is $31 to $117 million.

Table 4. Results of Price Cap Scenario Analysis

	Base Case ($250 Cap)[a]	$500 Cap[b]	$750 Cap[c]	Diff.[d]
Low Price Impact Scenario:				
Summer 1999 (plus 5%)	$122 M	$32 M	$63 M	$31 M
Summer 1998 (plus 5%)	$182 M	$80 M	$159 M	$79 M
High Price Impact Scenario:				
Summer 1999 (plus 5%)	$122 M	$55 M	$111 M	$56 M
Summer 1998 (plus 5%)	$182 M	$116 M	$233 M	$117 M

a. Base net-load cost in ISO real-time market at a $250 cap.
b. Cost increase from base case (a) of a $500 cap
c. Cost increase from base case (a) of a $750 cap
d. Additional cost in the ISO real-time market from leaving the cap at $750

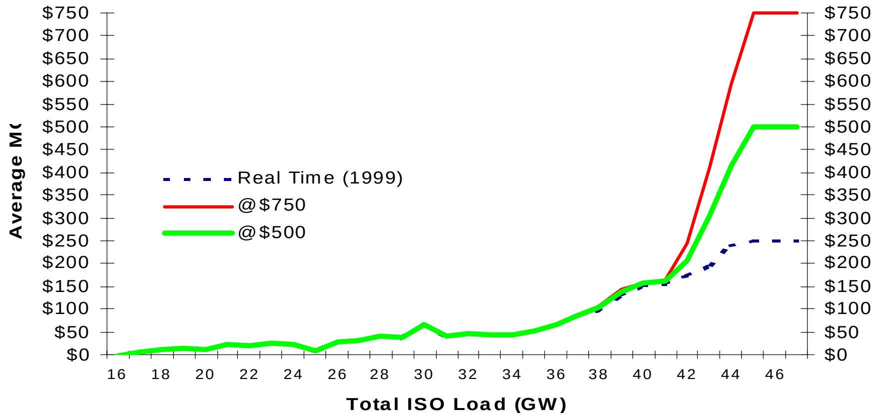
Figure 10 provides a more detailed illustration of study results for one of the scenarios used in the analysis: the low price impact scenario with 5% load growth over 1999 levels. As shown in Figure 10, this scenario assumes a significant increase in average energy prices at load levels above 42,000 MW due to a $500 or $750 price cap.

[8] The indirect incremental cost to the PX day-ahead energy market from leaving the cap at $750 versus lowering it to $500 are estimated between $43 M and $195 M.

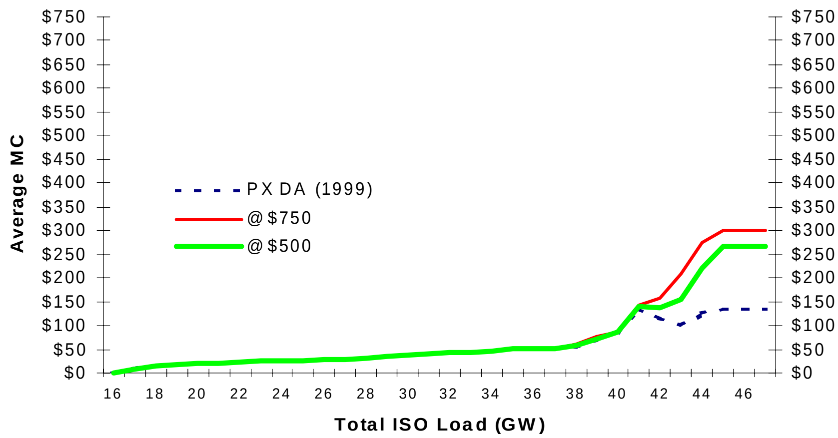
Figure 10. Sample Study Results

Low Price Impact Scenario with 5% Growth from 1999 Loads

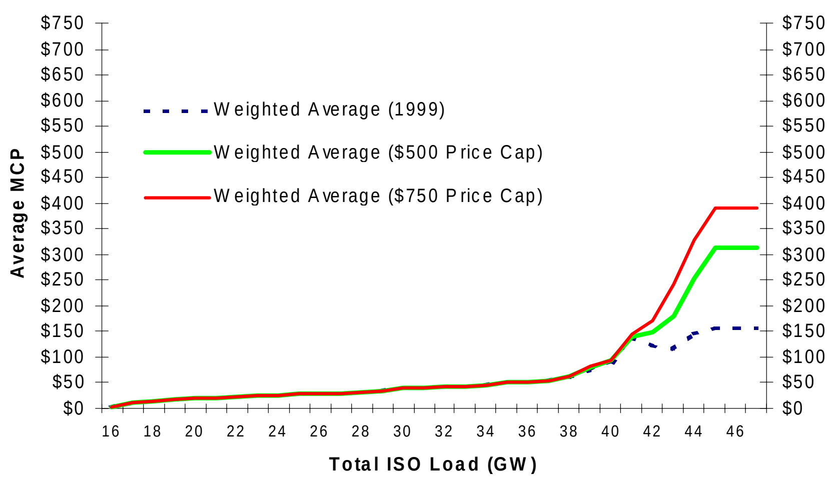
Real Time



PX Day Ahead Market



Weighted Average Energy Prices (PX + Real Time)



4. Assessment of Summer 2000 demand responsiveness program

4.1 A workably competitive market requires price-responsive demand

Workably competitive markets require a price-responsive demand side as well as a competitive supply side. Consumers must be able to receive market price signals and factor them into their consumption decisions. The ability of consumers to respond to high prices provides an important mechanism for mitigating market power.

With a price responsive demand, generators that try to exercise market power through bidding above marginal cost during high demand hours may find that any gain in profits from setting higher prices is more that offset by a loss in profits from reduced demand. Thus, with a price responsive demand generators have more of an incentive to bid their marginal cost. In the California electricity market, the ability of demand to respond to prices is quite limited at present.

A lack of price responsive retail demand for energy was identified by the ISO Market Surveillance Committee (MSC) as one of the main factors inhibiting the competitiveness of the California market.[9] The main reason for this is that most of the end-use consumers are under a retail rate freeze, under which they face flat monthly electricity rates that are not affected by the actual hourly prices of energy. The retail rate freeze, described more fully below, eliminates any incentives for loads to reduce demand at times of high system load and high prices. It is not a permanent feature of the market, however, and there is a likelihood it will be gone by Summer 2001.

The new regulatory structure created by Assembly Bill (AB) 1890 froze UDC electricity rates for residential and small commercial customers at 90% of 1996 levels and froze rates for large commercial customers at 1996 levels. Under this retail rate freeze the difference between the frozen rate and the UDC cost of providing energy — called the Competition Transition Charge or CTC — is applied to the recovery of stranded costs.

AB1890 gives the UDCs until March 31, 2002 to recover any stranded costs associated with uneconomic investments and contractual obligations, and thus sets a time limit to the rate freeze. Currently, only SDG&E has already recovered all of its stranded costs and, pursuant to AB 1890, is no longer

[9] See the Market Surveillance Committee's "Report on the Redesign of California Real time Energy and Ancillary Services Markets," October 18, 1999.

required to have its rates frozen at 90% of the 1996 levels.[10] PG&E and SCE are also expecting to recover their stranded costs before the March 31, 2002 date for termination of CTC. The CPUC is currently conducting a Post-Transition Ratemaking (PTR) Proceeding to determine consistent ratemaking practices for all three UDCs after the rate freeze.

In the interim, several new load responsiveness programs have been developed for Summer 2000. The UDCs have each developed Summer 2000 pilot programs for developing demand responsiveness in the PX day-ahead market. If approved by the CPUC, these new programs will allow SCE and PGE to bid up to 1,000 MWh of price responsive demand into the PX day-ahead market. Under these programs, participants would be paid an energy incentive payment for curtailing their demand. These programs are currently under CPUC review. In addition, the ISO has developed a Summer 2000 trial program for increasing load participation in the ISO ancillary service and supplemental energy markets. These new programs, though relatively small in scale, provide load with new opportunities to mitigate market power in Summer 2000 and represent a significant step towards developing price responsive demand.

4.2 UDC load curtailment programs

In November 1999, PG&E, SCE, and SDG&E filed separate Advice Letters to the CPUC proposing price-responsive load programs[11] for summer-fall 2000. Under these programs, when certain market conditions in the day-ahead PX market exist, the utilities would offer incentive payments to program participants who are willing to voluntarily curtail their energy usage. Each utility proposed different day-ahead market conditions for triggering the program.

Under SCE's proposal, incentive payments would be offered when the *unconstrained* PX day-ahead energy price equals or exceeds $250/MWh. PG&E's program is activated when the *constrained* PX day-ahead energy price equals or exceeds $250/MWh, and SDG&E's program is triggered when the utility believes the cost savings to bundled customers will exceed the incentive payments.

[10] Under an interim settlement, while the CPUC develops a comprehensive post-transition rate regime for all the UDCs, SDG&E can pass through all energy and energy related costs to its bundled-service or default customers (i.e., customers who do not choose a non-utility electricity provider under the Direct Access program). However, for the period July-September 1999, customer rates were capped at 112.5 percent of the frozen electric rate levels (which, combined with the legislated 10 percent rate reduction, translates to 101.25 percent of 1996 levels). Any revenue shortfalls SDG&E might have faced as a result of the cap were recoverable from customers in subsequent months.

[11] The utilities' current proposals are similar in many respects to the demand responsiveness programs submitted by PG&E and SCE in March 1999 and approved by the Commission for the summer of 1999, but which the utilities chose not to implement due to concerns about the programs being subject to reasonableness reviews and other modifications required by the Commission.

Under SCE's program, participating loads are paid the unconstrained PX day head price for each MWh of energy deemed curtailed. PG&E's and SDG&E's use the constrained PX day ahead price as an incentive payment. The intent of these programs is to develop price responsive demand that the utilities can bid into the PX day ahead market. In so doing, the utilities create a more price elastic demand curve which, under high priced market conditions, should result in lower PX day ahead energy prices.

To the extent these programs are able to lower the PX day ahead energy prices, all loads participating in the PX market benefit. Since utilities will not know which program participants are actually willing to curtail until after the close of the PX day ahead market, their price responsive demand bids would be based on forecasts of how much voluntary curtailment they would get under different incentive payment levels.

Curtailments are measured by taking the difference between a projected baseline usage (i.e., expected load absent the curtailment) and actual metered load. Each utility has its own method for calculating baseline usage, and there are some additional provisions concerning minimum and maximum curtailments eligible for payment

Under the proposed programs, only large bundled service customers (500 kW or greater) having interval metering would be eligible to participate. The SCE and PG&E proposals would also allow customers on interruptible tariffs[12] to participate, but SDG&E's proposal would not. The PG&E and SDG&E programs have limited participation, on a first-come-first-serve basis, to 500 and 100 customers, respectively. SCE did not limit the number of program participants but did limit the amount of curtailable load accepted in any hour to 500 MWh. A more detailed description of each program's features is provided in Appendix A.

On February 15, 2000, the CPUC issued a draft resolution[13] on the demand responsiveness programs submitted by SCE and PG&E, but has not yet ruled on SDG&E's request. In this draft resolution, the CPUC approved the two programs subject to the following modifications:

- PG&E and SCE expand their programs to allow up to 50 smaller customers (less than 500 kW of demand) to participate if they meet the metering and communication requirements;
- PG&E would be subject to a maximum total load reduction for any one curtailment event of 500 MWh, the same limit that SCE utilizes;

[12] Interruptible tariff customers could participate but with the provision that ISO events take precedent (i.e., no incentive payments in hours where the ISO called on the interruptible service).
[13] Draft Resolution E-3650 of the Energy Division.

- The administrative costs of the program for both utilities would be subject to reasonableness review;
- SCE and PG&E assign all costs of their program (both administrative and incentive payments made under the program) to the PX component of their customers' bills;
- SCE and PG&E should subtract the "otherwise applicable PX charge" in determining the level of incentive payment;
- SCE should pay program participants the PX constrained price to curtail rather than the unconstrained price; and
- Customers already on interruptible programs should not be eligible for the programs.

In early March, the CPUC issued a second draft resolution. This second draft resolution approves SCE's and PG&E's programs with the same modifications noted in the first draft resolution except the modification prohibiting customers already on interruptible programs from participating in the programs. The second draft resolution allows customers already on interruptible programs to be eligible for participation. The resolution will be on the March 16th CPUC meeting agenda, at which time the CPUC may vote on this resolution or postpone a vote until later.

One of the most contentious issue in the CPUC's draft ruling concerns the participation of interruptible customers. Loads operating under the existing interruptible tariffs receive lower energy rates for their willingness to curtail when operating reserves are low.

Both the PG&E and SCE proposals allow interruptible customers to participate in the demand responsiveness programs with the provision that such customers would not get paid under the program in hours where the ISO calls for them to curtail under their existing interruptible contracts. The utilities developed this provision as a way of avoiding a "double-payment" (i.e., the interruptible customer is already being compensated through receiving lower energy rates). The CPUC points out, however, that "it is unclear if this approach alone is sufficient to prevent occurrences of double payment. For example, this approach does not reflect the possibility that interruptible customers would have been curtailed 'but for' the voluntary curtailment programs of the utilities."

There is also a "double-counting" issue, which can arise if the utility accepts a curtailment from an interruptible customer under a demand responsiveness program and fails to notify the ISO. In this case, the ISO would be relying on curtailable load that is not actually available.

4.3 Load Participation in ISO Ancillary Services and Supplemental Energy Markets

Facilitating load participation in ISO ancillary services and supplemental energy markets has been identified as a key element to the ISO ancillary service redesign process. Though the ISO Tariff contemplates the participation of loads in ancillary service markets[14] (ISO Tariff, section 2.5.6), participation has been hampered by the absence of a form of agreement that would set forth the terms and conditions that would govern a dispatchable load's provision of ancillary service. The ISO's objective is to have the necessary rules, procedures, and systems operational in time to allow loads to participate in these markets (as ISO Participating Loads) before Summer 2000.

As part of this effort, a pro forma Participating Load Agreement (PLA) was filed as part of Amendment No. 17 to the ISO Tariff and was subsequently accepted by FERC. The PLA binds loads participating in the ISO's supplemental energy and ancillary services markets to the ISO Tariff, just as the ISO's pro forma Participating Generator Agreement binds generators.

The ISO also filed tariff changes with the FERC in Amendment No. 17 to specify the conditions under which loads subject to existing retail interruptible service arrangements may participate in the ISO's ancillary services markets.

Those conditions include:

- authorization by the California Public Utilities Commission (CPUC) or other Local Regulatory Authority, and
- mitigation of any incentives under the retail service arrangement to be unavailable or incapable when the ISO is relying on the capacity.

A variety of requirements apply to loads that participate in the ISO markets, including requirements related to metering, scheduling, dispatching, and ISO EMS Telemetry, as well as contractual, certification and testing requirements. Several loads (primarily large pumps) meet all current ISO requirements today and are already participating in the ISO markets.

Further expansion of load participation in the ancillary services markets depends on the ability of loads to aggregate and still meet ISO requirements. For aggregated loads, particular issues arise with regard to communication requirements supporting ISO EMS Telemetry. The ISO EMS must obtain near real time values for participating loads providing ancillary services, in order for the ISO to continuously monitor the status, location and amount of reserves

[14] Due to the nature of the requirements for Regulation and Spinning Reserve, load participation is limited to the ISO markets for Supplemental Energy, Non-Spinning Reserve and Replacement Reserve.

available to meet reliability criteria set by the Western Systems Coordinating Council (WSCC) and the North American Electric Reliability Council (NERC). To address visibility and other issues related to load participation in ISO markets, a Participating Load Working Group (PLWG) was established at the ISO.

In recent months, the ISO PLWG has been developing the technical and contractual requirements for loads to participate in the markets for non-spinning and replacement reserves and supplemental energy. The key activities and issues relating to load participation in the ISO real time markets include:

- technical standards, including metering and telemetry requirements;
- certification and contractual requirements;
- determining whether loads have sufficient incentive to participate in the market with the above technical and contractual requirements, considering the implications of 10-minute settlements and the ISO no-pay provisions for ancillary services; and
- what further avenues should be pursued outside the current ISO programs to promote demand responsiveness.

A technical principle paper was provided to market participants in early December 1999, and a forum was held at the ISO on December 16 for potential load participants to discuss the contents of the document and rationale for the requirements. Comments received during that forum and subsequent to it have centered on relaxing the telemetry scan rate requirements for providing non-spinning reserve, waiving or relaxing no-pay provisions, and some relaxation of the metering requirements.

In response to these concerns, ISO management proposed relaxing some of the technical standards in a proposed trial program for June 15 to October 15, 2000 (Summer 2000). Under the proposed trial program, the ISO agreed to relax scan rates for EMS telemetry, relax no-pay provisions, and change the meter data requirements. Because of concerns about the potential operational impact of these relaxed standards, the ISO has initially limited Summer 2000 load participation to 400 MW for non-spinning reserve, 400 MW for replacement reserve, and 1,000 MW for supplemental energy.

The ISO will consider revising these limits once there is a better sense of the response and interest in the program. This Summer 2000 trial program was presented to potential load participants at a forum on February 22, 2000. Some of the potential load participants at this forum indicated that they could meet these requirements.

4.4 ISO emergency demand reduction 2000

Due to some recent concerns over supply adequacy for Summer 2000 and the desire to begin developing a curtailable product that could potentially replace the UDC interruptible programs when these programs expire in March 2002, the ISO has worked with stakeholders to develop an emergency demand reduction product. Up to 1,000 MW of load could participate in this program. The ISO and interested parties held conference calls on March 2nd and March 9th to develop the specific design features of the program.

A detailed description of the program will be incorporated into a Request for Proposals document (RFP), which will be sent out to market participants for response by March 18th. It is contemplated that the program would appeal to a broad population of loads that could participate in a multi-hour emergency curtailment. Under the program, participants would be available for curtailments over a four-month period from June 15 to October 15, 2000. Participants would be selected through an RFP process and would receive special payment provisions for emergency curtailments.

4.5 Summary

The utilities' demand responsiveness programs and the ISO's participating load programs are positive steps toward developing price responsive demand in California's energy markets. While these programs are relatively small in scale[15] and participation levels are unclear, the programs will provide useful information on the extent to which different types of loads will respond to market prices. In addition to providing some demand responsiveness for this year, the experience gained from these programs will help in the long-term development of future programs.

Whether it is appropriate for loads operating under existing interruptible tariffs to participate in price responsive programs is a complicated issue. The CPUC and others have expressed concern over double paying interruptible customers, though the UDC programs have provisions that such customers would not get

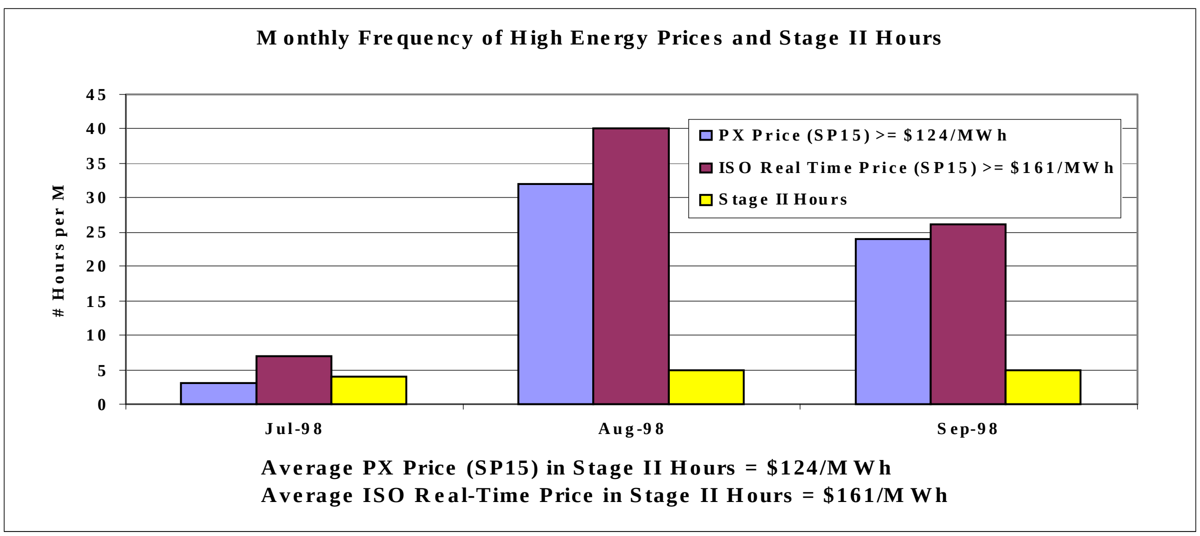
[15] Under the current participation limits in both programs, there could be 2,800 MWh of price responsive demand (1,000 MWh from the UDC programs and 1,800 MWh from the ISO's participating load programs). The average super-peak load for summer 1999 was approximately 35,000 MWh. Based on these numbers, maximum participation in these programs would result in about 8% of the total peak load being price responsive. However, it should be noted that some load (predominately pump-hydro load) already participates in the ISO's real time market. On average, approximately 450 MW of load is bid into the ISO market for non-spinning reserve during non-peak hours and approximately 200 MW during peak hours. Since the ISO typically does not purhase replacement reserve during off-peak hours, and replacement reserve prices during peak hours are generally lower than prices for non-spinning reserve, there is very little curtailable load bid into the replacement reserve market. In addition, approximately 350 MW of curtailable load is bid into the ISO real time market during off-peak hours as supplemental energy, and approximately 30 MW during peak hours.

paid under the program in hours where the ISO calls for them to curtail under their existing interruptible contracts. The CPUC pointed out that these provisions do not reflect possible cases where the interruptible customers would have been curtailed "but for" the voluntary curtailment programs of the utilities. In addition, the CPUC has to balance the merits of allowing curtailable loads to participate with the objective of fostering retail competition.

Some of the loads operating under curtailable tariffs have already switched to direct access service. Allowing curtailable loads to participate in the UDC demand responsiveness programs may entice some of the direct access loads under curtailable rates to switch back to their UDC.

To put the double payment issue in perspective, Figure 11 compares, for Summer 1998, the number of hours the ISO operated under a Stage II emergency to the number of hours PX and ISO real time energy prices exceeded the average hourly energy price during Stage II events. If, in 1998, energy prices during Stage II events were high enough to entice loads to curtail without being called under their curtailment contracts, then Figure 11 demonstrates that there were plenty of other hours in August and September where the ISO was not under Stage II, and prices were high enough for curtailable loads to respond. In other words, there were plenty of other hours where curtailable loads could have provided price-responsive demand without being double paid. This figure suggests that there may be a net benefit from having curtailable loads participating in these programs despite the potential for double payment.

Figure 11. Monthly Frequency of High Energy Prices and Stage II Events



The UDCs have also expressed concern that if interruptible customers are excluded from the program, actual participation in the programs could be significantly less than the individual program limits of 500 MWh.

5. Assessment of CalPX Hedging Products for Ancillary Services and Energy

5.1 Increased ability to forward contract will increase the competitiveness of the California energy market.

An important feature of a fully developed commodity market is the ability of buyers and sellers to contract well in advance of the actual "date of delivery". Such ability provides for greater price discovery and enables both sides of the market to hedge against price volatility in the spot market.

Until the development of the CalPX Block Forward Energy Market in June 1999, the only forward market option for the UDCs was the PX day-ahead and hour-ahead market. With no options for contracting for energy beyond a day-ahead basis, the UDCs were very limited in their ability to hedge. However, since July 1999, the UDCs have actively participated in the CalPX Block Forward Energy Market. This market enables the UDCs, subject to CPUC imposed maximum trading limits, to contract for energy up to 12 months in advance of delivery. This spring, CalPX will be offering a number of new block forward energy products including, super peak and shoulder peak energy products and peak energy products from Arizona, Nevada, and the Pacific Northwest. In addition, the CalPX plans to have a block forward market for ancillary services in place by May 1, 2000[16]. All of these new products provide the UDCs with new hedging opportunities and will help to improve the overall competitiveness of the California market.

5.2 CalPX block forward market for ancillary services

On February 17, 2000 the California Power Exchange filed with FERC on behalf of its CalPX Trading Services[17] (CTS) a request for authority to conduct a block forward market for ancillary services and for the CalPX to provide scheduling of bilateral ancillary service transactions. Provided FERC approves the filing, CTS is planning to implement trading of ancillary services in its block forward market beginning on May 1, 2000 for June delivery. Forward trades and registered bilateral agreements for ancillary services will be scheduled for delivery in the CalPX day ahead market.

---

[16] This proposed program is currently under FERC review and UDCs will need approval from the CPUC to participate in this new forward market for ancillary services.

[17] CalPX Trading Services" (CTS) is a non-incorporated division of the CalPX for the purpose of separating the block forward market, for financial, administrative, regulatory, and organizational reasons, from the existing markets operated by the CalPX.

CTS will list contracts for the five physical ancillary services in NP15 and SP15: regulation up, regulation down, spinning reserves, non-spinning reserves and replacement reserves. Initially, three different products will be offered for each regulation type: on-peak, off-peak, and super peak (see Table 5). These six different regulation products will be offered only on an experimental basis for June and July delivery periods. The PX will evaluate the regulation contracts and most likely will discontinue one or more of the initial offerings, depending on trade volume. Only an on-peak product will be offered for spinning, non-spinning, and replacement reserve, and these contracts will be listed four months forward. Once the PX has a better sense of which trading products are most preferred by participants, they will list ancillary service products 12 months forward.

Table 5. CalPX A/S Block Forward Market Products

Ancillary Service	Type	Days	Hours
Regulation - Up	On-Peak	Mon-Sat	HE 7-22
Regulation - Up	Off-Peak	Mon-Sun	HE 1-6, 23,24 (Sunday all hours)
Regulation - Up	Super-Peak	Mon-Sat	HE 15-24
Regulation - Down	On-Peak	Mon-Sat	HE 7-22
Regulation - Down	Off-Peak	Mon-Sun	HE 1-6, 23,24 (Sunday all hours)
Regulation - Down	Super-Peak	Mon-Sat	HE 1-8, 23,24
Spinning Res.	On-Peak	Mon-Sat	HE 7-22
Non-Spinning Res.	On-Peak	Mon-Sat	HE 7-22
Replacement Res.	On-Peak	Mon-Sat	HE 7-22

Unlike the PX block forward market (BFM) for energy where contracts are settled against the average monthly PX zonal price, the ancillary service block forward market is not a contract for differences. Contracted capacity is simply settled at the contracted price. However, if a CTS *seller* (bilateral or BFM) fails to deliver its committed ancillary services, CalPX will charge the seller at the hourly CAISO weighted average price for all quantities that CalPX purchased from the ISO to replace the ancillary service shortfall.

Conversely, if a CTS seller provides ancillary services to CalPX (bilateral or BFM) in excess of capacity committed to CTS, CalPX will reimburse the seller for any surplus capacity at the CAISO weighted average price, provided the CAISO has accepted such excess. If a CTS *buyer* (bilateral or BFM) has a load obligation that exceeds the amount of CTS ancillary services, the CTS buyer will be charged at the CAISO weighted average price for all capacity purchased to supplement the CTS purchases. Conversely, if a CTS buyer has a load obligation less than the amount of CTS ancillary services purchased, the CTS buyer will be paid at the CAISO weighted average price for all excess capacity used by the CAISO or other CalPX participants.

In order to participate in the CTS block forward market for ancillary services, the three utilities will have to file advice letters with the CPUC. They have not done this. The robustness of this market will largely depend on UDC participation.

5.3 CalPX Block Forward Market for Energy

In June 1999, the California Power Exchange introduced a new block forward market for energy. The CTS BFM trades standardized contracts for a calendar month of on-peak energy for delivery in either congestion zone NP15 or SP15. The contracts are in multiples of 1 MW or 25 MW blocks for the on-peak time period (6:00 a.m. to 10:00 p.m. Monday through Saturday, excluding certain holidays). These contracts are contracts for differences and are settled against the monthly average PX day ahead zonal price.

The CTS BFM contract was developed based on input from market participants who wanted CalPX to offer a standardized contract on a forward market basis to trade on-peak blocks of power for an entire month at a single price. Offering this type of product provides market participants with a market to hedge against hourly price variation associated with the CalPX day-ahead PX market.

In November 1999, the CalPX introduced a new quarterly block forward market for energy. Under this new contract, blocks of peak-hour power can be traded for an entire quarter at a single price. Quarterly products are currently being traded for the 2nd, 3rd, and 4th quarters of 2000.

In addition, the CalPX has recently filed with the FERC for authority to offer block forward energy products for delivery points outside of California. If approved by the FERC, the CalPX plans to offer block forward energy products for delivery on Mead, Palo Verde, and COI, with trading beginning in May 2000.

There are currently eleven different companies participating in the CalPX block forward market (Table 6)

Table 6. Active Participants in Cal PX Block Forward Market

Company	Activation Date
Enron Power Marketing, Inc.	June 30, 1999
Electric Clearing House, Inc.	July 2, 1999
Southern California Edison	July 16, 1999
Pacific Gas & Electric	July 22, 1999
Avista	July 27, 1999
San Diego Gas & Electric	August 18, 1999
Statoil Energy Trading, Inc.	October 15, 1999
Duke Energy Trading & Marketing	October 22, 1999
PG&E Energy Trading	November 23, 1999
American Electric Power	January 10, 2000
William Energy Service Company	January 12, 2000

Figures 12 and 13 show the monthly volumes that have traded in these market for 1999 and 2000 (to date).

Figure 12. Monthly Block Forward Market Volumes (SP15)

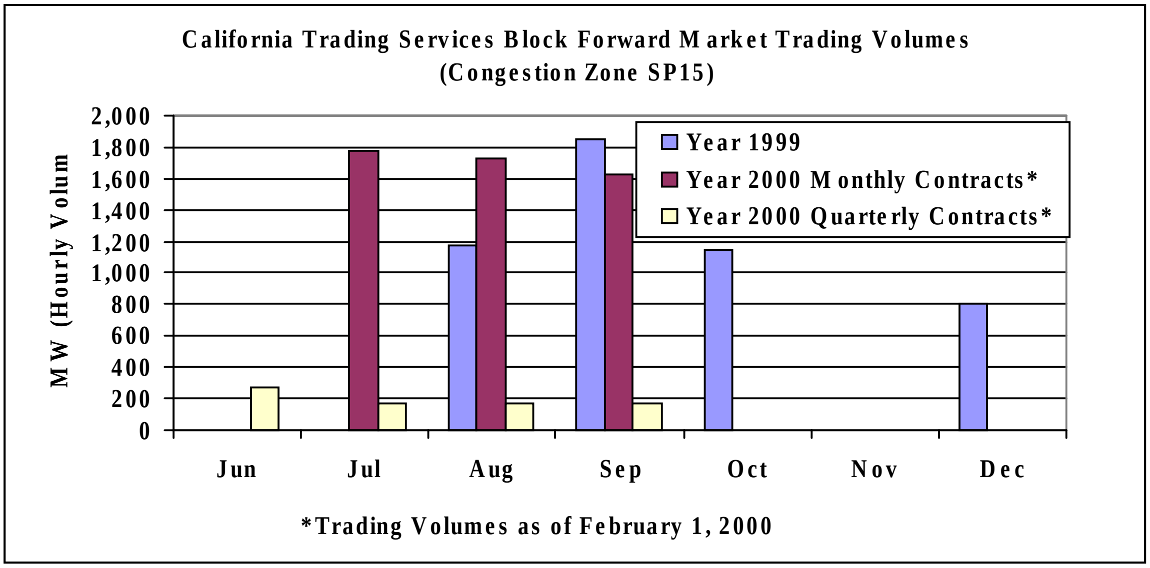
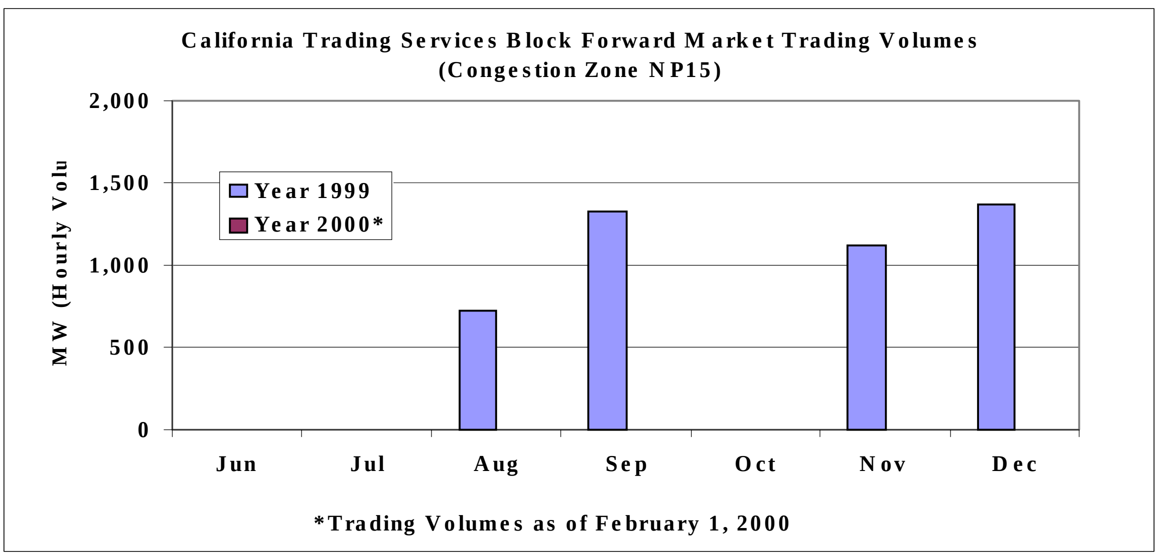


Figure 13. Monthly Block Forward Market Volumes (NP15)



Though implemented in June 1999, trading in the CalPX BFM did not actually occur until July 1999 for the delivery periods of August - December 1999. Trading has been most active in congestion zone SP15. Figure 12 compares trading activity in SP15 for 1999 and 2000. In 1999, approximately 1,200 MW of BFM energy contracts were traded in SP15. The number of SP15 BFM contracts traded for September 1999 increased to 1,800 MW, and trading declined to 1,100 MW for October 1999. BFM trading for Summer 2000 is still ongoing. To date, the number of contracts traded for Summer 2000 in SP15 has already exceeded 1999 levels, averaging approximately 2,000 MW for the delivery months of July-September.

Trading for NP15 contracts has been more moderate. In August 1999, approximately 700 MW of BFM energy was traded in NP15. Trading increased in September to 1,300 MW. No contracts were traded in October, but trading resumed in November and December at levels of 1,100 MW and 1,400 MW, respectively. As of February 1, 2000, there have been no BFM trades in NP15 for 2000.

It is important to note that the three participating utilities have CPUC-imposed limits on the total BFM energy that can be contracted (Table 7). To mitigate concerns over market power, the CPUC limited the utility's trading limits to one-third of their historical minimum hourly load by month.

Table 7. Estimated Current BFM Trading Limits for Peak Season

Utility	Estimated Trading Limits for Peak Season
SCE	1,800-2,000 MW
PG&E	2,000 MW
SDG&E	300-400 MW
Total	**4,200-4,400 MW**

Under these trading limits only about 2,400 MW of bundled customer load in SP15 can be hedged, and only about 2,000 MW of bundled customer load in NP15. In January 2000, both PG&E and SCE filed advice letters with the CPUC requesting expanded trading authority in the CalPX BFM. In these advice letters, the utilities requested cost recovery authority for new energy products being offered by the CalPX BFM, a change in the termination date authorizing participation in the CalPX BFM from October 2000 to March 2002, and an increase in the CalPX BFM quantity trading limits imposed by the CPUC.

SCE requested increases in their trading limits by quarter and requested a limit of 2,200 MW (1st and 2nd Qtr), 5,200 MW (3rd Qtr), and 3,000 MW (4th Qtr). PG&E requested their trading limits be raised to 3,000 MW for all months. In a draft resolution issued by the CPUC on March 16, 2000, the Commission approved cost recovery of new energy products but denied the utilities requests for extending the termination date and for higher trading limits. The Commission explained that extending the term and expanding the trading limits would be premature and cited their original resolution issued of July 8, 1999 authorizing SCE and PG&E to participate in the CalPX BFM (Resolution E-3618).

In this original resolution, the Commission explained that limiting authority to October 2000 would provide an adequate time to review the efficacy of the CalPX BFM and "will allow time for analysis and the implementation of any appropriate changes before the next peak season begins." In the March 16, 2000 draft resolution, the Commission affirmed this position, stating that increasing the term and trading limits at this point and time would be premature. Though the trading volume shown in Figure 12 would suggest the utilities in SP15 are near their trading limits, the Commission noted that, to date, neither PG&E nor SCE has fully utilized their current position limits.

In a second draft resolution issued March 13, 2000,.the CPUC granted SCE and PG&E authority to trade up to their "net-short position"[18] in the CalPX Block Forward Energy Market and extended their authority to the end of each utilitiy's respective rate freeze.

5.4 Summary

Though it is still subject to FERC approval, it appears the CalPX will have a monthly block forward market for ancillary services in place by May 1, 2000. This market will provide a new opportunity for UDCs to hedge against day-ahead and hour-ahead ancillary service prices. The UDCs will need to request authority from the CPUC to participate in these markets. As of March 8, 2000, neither SCE nor PG&E have filed an Advice Letter to the CPUC for participation in this market.

The CalPX BFM for energy has become a more active market with significantly more participants and energy products than when the program was first introduced in June 1999. However, the trading limits imposed by the CPUC on the utilities limit their ability to fully hedge their net-load positions in the market. Both SCE and PG&E have requested increases to their trading limits and in a recent draft resolution the CPUC approved their request. Under this draft resolution, the two UDCs are allowed to hedge 100% of their net-load position.

These new CalPX block forward energy and ancillary service products provide the UDCs with new hedging opportunities and will help to improve the overall competitiveness of the California market. It is anticipated that the CPUC will rule on the utilities' request for expanded BFM energy trading on March 16, 2000.

[18] A "net-short position" is the utility's total bundled service hourly demand less the amount of generation the utility provides in that hour.

6. Other Criteria Relevant to the Summer 2000 Price Cap Level

The Board's August 1999 resolution on price caps identified the items discussed in the previous sections as specific criteria to be used in determining whether the caps should stay at $750 for Summer 2000 or be reduced to $500. Several other factors have been identified in the course of ongoing price cap discussions at the Board and at stakeholder meetings at the ISO. This section discusses each of these issues in relation to the decision about where to set the Summer 2000 price cap level.

6.1.1 Supply Adequacy Under Coincident Peaks in the Southwestern Region

Summer peak loads in the ISO system were just below 45,000 MW in 1998 and just below 46,000 MW in 1999. Even if Summer 2000 is only a "normal" summer, peak load is expected to exceed 46,000 MW. If it hotter than normal, but still within "reasonable" limits, peak loads would of course be higher.

During such peaks the ISO has to rely on imports to meet load. During Summer 1999 the ISO and its neighboring control areas did not experience peak loads at the same time. This is not something we can depend on, however, as a heat wave across the Southwest region has in the past and could again result in "coincident peaks" in adjacent control areas, including the California ISO control area. Under coincident peaks, out-of-state suppliers will tend to respond to the highest prices they can earn at the moment.

As the previous sections have described, Summer 2000 will see substantially greater capability to meet peak loads through voluntary load curtailment than in the past, and this should somewhat mitigate the potential threat of out-of-state supply being unavailable. At the same time, load has grown since a year ago, and Summer 2000 will quite likely be hotter than Summer 1999, which was relatively mild by historical standards. We believe, therefore, that maintaining the higher price cap level is a prudent step to make the California markets more attractive to import supply in the event that loads and prices go up at the same time here and in adjacent control areas.

6.1.2 Need for Meaningful Observation of Market Performance Prior to November 2000 Termination of FERC Price Cap Authority

A key argument the ISO made in recommending higher price caps to the Board in August 1999 was that a higher price cap level would provide more meaningful observation of how well the markets performed with the new design changes that were implemented at that time. The logic of this argument is that a lower cap will be hit more frequently than a higher cap, and therefore the higher cap allows a greater range of prices over which the market can clear under a greater range of system conditions and load levels. Simply stated, a higher cap looks more like an uncapped market than a lower cap, and thus provides better information about how an uncapped market is likely to behave. This factor would therefore imply that it would be better to keep the cap at the higher level for Summer 2000, particularly in light of the expiration on November 15, 2000 of the ISO's authority to impose price caps in its markets. Moreover, in light of the fact that there are new market design changes planned for Summer 2000 (10-minute settlement and automatic dispatch system), it would be beneficial to be able to observe the market at the higher cap level to assess how well these new elements are working.

Finally, if there is any possibility that the ISO will want to ask FERC for price cap authority beyond November 15, 2000 (even if only on a safety-net basis at an extremely high level), our filing to FERC would be stronger based on Summer 2000 observation at the higher cap level.

6.1.3 Signals for New Investment and Consistency of ISO Price Cap Policy

As we have mentioned at various points in the foregoing discussion, the impact of high prices on the incentives for new supply investment and enhanced demand responsiveness will depend much more on the market's confidence in the ultimate elimination of price caps than on a $250 increment in the price cap level for the coming summer. It is important, then, to think about the Summer 2000 price cap level not just in terms of the immediate effects this summer, but also in terms of how this level can better facilitate the transition away from reliance on price caps in the ISO markets.

In that sense, it may be argued that the August 1999 resolution was, in itself, only a strategy for achieving the Board's more fundamental policy objective, namely, to move as expediently to a workably competitive market regime in which price caps are no longer needed (except for a very high safety-net cap level). Following this logic, the Board would set the Summer 2000 price cap level so as to best serve the more fundamental policy objective and facilitate the expedient movement to uncapped market prices. Following this logic, then, the Board could decide that there are good reasons to maintain the cap at the $750 level even though the criteria stipulated in the August 1999 resolution may not lead unambiguously to that conclusion. It could reach this decision if, for example, the $750 price cap level would facilitate better the movement to an uncapped market price regime.

6.1.4 Potential Impact of the Price Cap Level on the Timing of Ending the Rate Freeze

In Section 4 we discussed the absolute importance of having a demand side that can respond to prices in order to have a workably competitive market, and the ways in which the current rate freeze and CTC collection regime mute the incentives for demand to respond to prices. Another relevant feature of the CTC collection regime is the fact that CTC collection is slower when the PX energy credits — which reflect the costs of ISO-procured services as well as the cost of PX energy — are high, and faster when they are low.

Based on this feature, the argument has been made that the California markets will not be truly workably competitive until the transition period — characterized by the rate freeze and the collection of CTC — ends, and that a lower price cap level in Summer 2000 will hasten that end.

The DMA accepts the logic of this argument. We do not believe, however, that a price cap level of $750 rather than $500 is likely to have a significant impact on the timing of the end of the rate freeze. Historically, CTC payments collected from SCE's and PG&E's "head room"[19] have been approximately $218 million per month. In this report, the annual cost impact from leaving the cap at $750 versus $500 is estimated to be, under a high summer load scenario, roughly $170M-$310 M. Based on these numbers, the incremental cost of leaving the price cap at $750 versus lowering it to $500 may extend the rate freeze by only four to six weeks, assuming that the UDC would recover their CTC prior to the rate freeze termination date of March 2002.

6.1.5 Incentives for Development of Greater Load Responsiveness

A $750 cap will provide a greater incentive for participation in the load responsiveness programs developed for Summer 2000. Greater participation in these programs will provide useful information on the extent to which different types of load will respond to market prices. This information will be very useful in developing future load participation programs and will also help the ISO in developing a market power mitigation policy after Summer 2000

6.1.6 Distributional Effects of Price Cap Policy

The level of the price cap will clearly have distributional effects. In a purely static sense, other factors held constant, moving the price cap from a lower to a higher level will result in higher costs to consumers[20] and higher payments to producers. Whether or not this is seen as desirable is highly subjective, and is not something upon which DMA can render an opinion. We feel it is important to mention this effect, however, because it will likely be a significant factor in the Board's discussion of the Summer 2000 price cap level.

[19] The difference between the UDC's monthly revenues and costs of providing energy.

[20] Because most end-use consumers are protected by a rate freeze (i.e., PG&E and SCE loads), the level of the price cap will not have a direct impact on most end use consumers. The main impact will be on the UDC's ability to recover stranded costs.

7. Post-Summer 2000 Price Cap Policy Options

Looking toward the expiration of price cap authority on November 15, 2000, DMA is concerned that some impediments to workable competition remain. As we argued in the discussion of workable competition, there are certain features intrinsic to the power industry that make it impossible to have workable competition 100% of the time. In particular, this industry will always (at least, for the foreseeable future) be characterized by:

- relatively few suppliers, each having a large enough share of the market to be pivotal in some hours, either at high loads or under certain outage conditions;
- a level of total system capacity that is less over-built in the restructured industry than was characteristic of the traditional integrated monopoly utility industry structure; and
- locational market power, due to the need for certain resources to increase or reduce their output at certain hours to maintain system reliability or relieve congestion.

As a result of these "permanent" features of the restructured industry, some permanent means to mitigate market power effectively needs to be established. At the same time, there are some aspects of the current state of competition that will improve and, with their improvement, will reduce the need for non-market means to prevent inefficient outcomes. In particular, there are some major market design improvements underway at the ISO which will enhance market efficiency (the FERC-ordered reform of congestion management, plus 10-minute dispatch and settlement), and the rate freeze that currently insulates most loads from hourly price signals should come to an end during the coming year. Thus we can expect substantial improvement in the state of workable competition in California, with the caveat that there will always be some high-load hours and some system conditions where market power mitigation will be needed.

We recommend, therefore, that the Board begin now to consider the various policy options that would be effective in protecting the ISO markets against the exercise of market power beyond that date. Some such capability will be needed both on a temporary basis — i.e., until the ISO implements congestion management reforms as ordered by FERC and the 10-minute dispatch and settlement provisions, and the retail rate freeze comes to an end — and on a permanent basis to mitigate market power in certain instances where specific resources would be able to drive up the market clearing price or the payment they receive in a way that is not connected to meaningful investment incentives.

Without going into great detail on the options at this time, this section will just identify the main policy options the Board might pursue. These are:

1) Take no further action and allow all price cap authority to expire on November 15, 2000. The DMA recommends against this option because it ignores both the near-term and the long-term needs to deal with market power mitigation.

2) Apply to FERC for safety net authority only. The ISO could implement a safety net either in the form of a very high backstop price cap (in the range of $2,500 to $5,000 for example), or as a provision for discretionary authority of the CEO to act quickly to limit prices under extreme circumstances, with rapid follow-up consultation with the Board. This may be a reasonable path for the Board to take even before observing market performance during Summer 2000, because it would provide a way to protect against uneconomic extreme prices after November 15 but before the ISO has the opportunity to fully assess Summer 2000 performance; evaluate more detailed policy options with stakeholder input; reach a Board policy decision; file that decision at FERC; and receive a FERC ruling.

3) Apply to FERC for more general authority that would allow the ISO to maintain a moderate level of price caps for a certain time period while certain remaining impediments to workable competition are being eliminated, at which time the ISO would retain only the safety net. The conditions for moving to the safety-net-only regime could include presently anticipated reforms to the ISO markets as well as external conditions, particularly the termination of the rate freeze and the CTC, which will impede demand responsiveness as long as they are in effect. As noted above, however, it will be virtually impossible to devise and to justify the details of such a policy before a full evaluation of Summer 2000 experience, and still have something filed at FERC and approved before November 15.

4) Implement an alternative to market-wide price caps to mitigate market power in both the near term and the long term. For example, the Board could consider the mechanism used by the PJM ISO (an individual bid cap for each generator based on its costs), which would provide a basis for payment when that generator is called for local reliability or congestion mitigation, and there is no way to meet these needs through the competitive bid process. The DMA is examining the approaches of other ISOs (primarily PJM, New England, and New York) for mitigating market power, managing congestion, and dealing with other problems we face in California. We will be informing

the Board on lessons we can learn from those approaches. As with option 3 above, however, this is not an option we can develop and file in time for approval by November 15.

In conclusion, the DMA intends to explore these and perhaps other options further, and will report to the Board at a later date on their pros and cons. We point out, however, that if the ISO were to file at FERC 60 days before the November 15 expiration date to extend its price cap authority, there would not be adequate time to fully assess Summer 2000 market performance and develop a policy recommendation based on that analysis. The Board should therefore consider the possibility of filing for a limited extension, say to February 15, 2001, for the purpose of fully assessing Summer 2000 experience, developing and comparing options with stakeholder input, reaching a Board policy decision in November, and filing in December.

8. Summary of DMA Recommendations

Based on the foregoing discussion, the DMA makes the following recommendation to the Board:

> *For Summer 2000, the DMA recommends that the Board maintain price caps at the $750 level.*

Given that price cap authority expires on November 15, 2000, the DMA recommends that the ISO initiate a stakeholder process to consider alternatives to price caps for the long-term. The precise design of a price cap policy for the post-November period should be developed using Summer 2000 experience and in coordination with congestion management reform. This may require requesting a limited extension of the current price cap authority to provide protection against market power abuse. The extension would allow the ISO to review the Summer 2000 experience and develop effective permanent measures to mitigate market power that are integrated with congestion management reforms. The ISO will be reviewing the merits of requesting a price cap extension and discussing other options with stakeholders and anticipates requesting some type of Board action on this issue in April 2000.