Cost Curve Analysis of the California Power Markets

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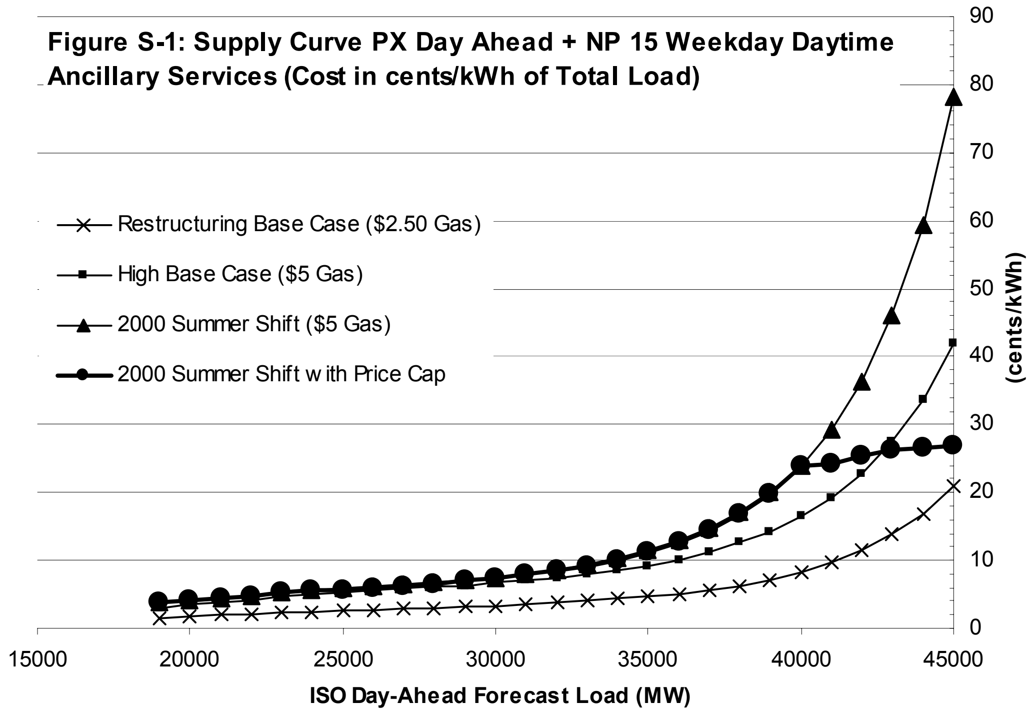
INTRODUCTION AND SUMMARY

A review of the California Power markets was prepared using regression analysis for California PX day-ahead market, the ISO imbalance market, and reserve and regulation markets for ancillary services. Two critical points have become clear:

1) There was a shift in the cost curve in California in the vicinity of May-June, 2000. ("2000 Summer Shift"). Virtually all power and ancillary service products became more expensive, particularly at load levels above 30,000 MW, even after accounting for both the rise in gas prices and the high load levels. (Figure S-1)



2) Because of the change in market organization due to the power pool, the value of demand reduction to California consumers far exceeds the market price for electricity. There is a huge financial externality that results from reducing consumption of electricity. Reductions in consumption reduce costs for the entire state. This point is of critical importance supporting the need for imminent revival and expansion of DSM programs, and provides a strong economic argument against regressive rate design policy (high fixed customer charges) that promotes consumption of electricity. Figures S-2 and S-3 show this impact.

Figure S-2:
Market Price vs. Value of Demand Reduction2000 Summer Shift Case, Capped, 40% Physical Hedge

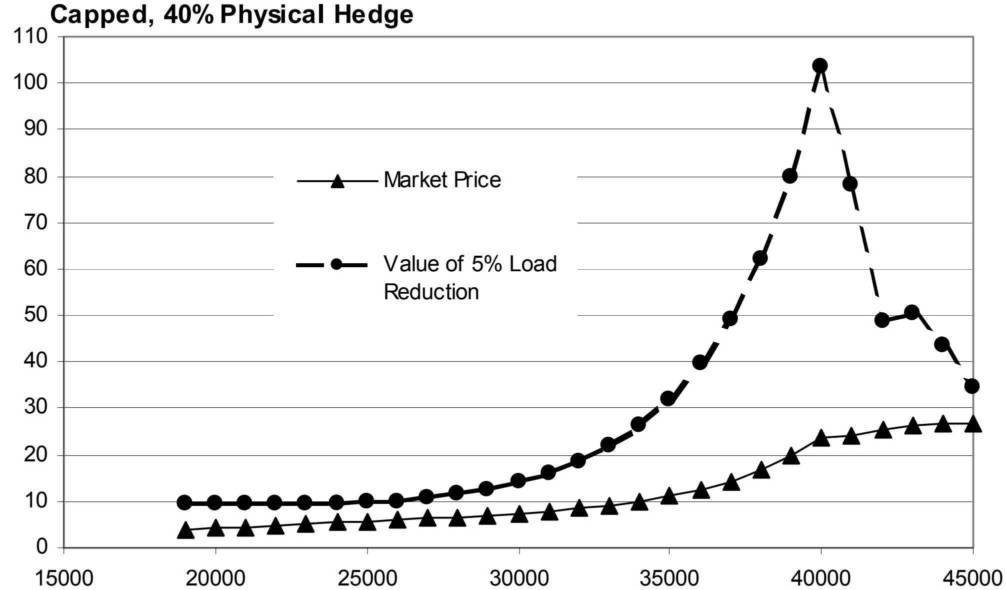
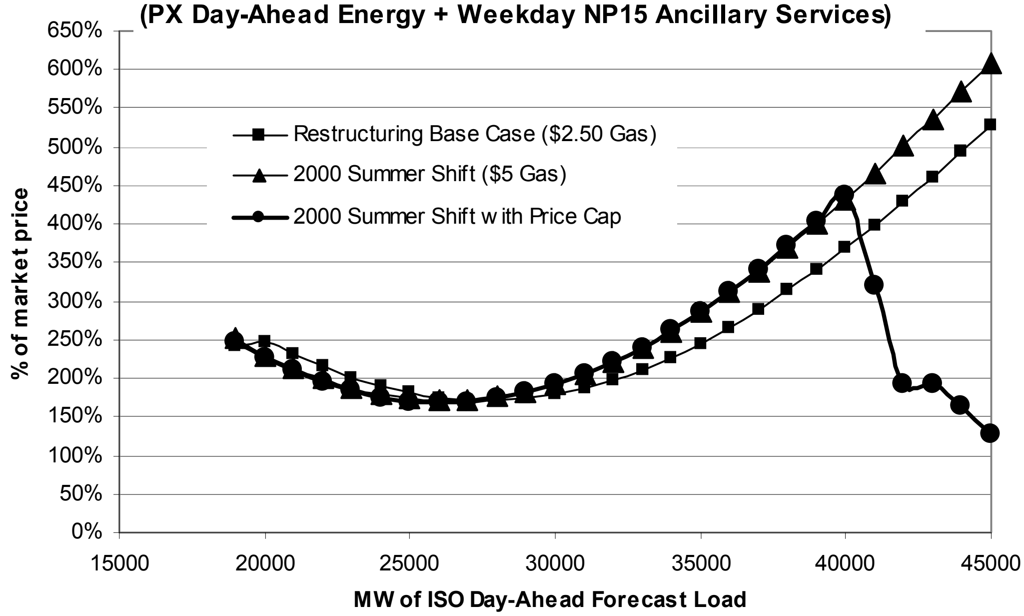


Figure S-3:
Value of 5% Load Reduction
as % of Market Price, 40% physical hedges
(PX Day-Ahead Energy + Weekday NP15 Ancillary Services)



COST CURVE STRUCTURE AND SUMMER SHIFT

The structure of the cost curve in California was analyzed for three separate markets: the PX Day-Ahead Unconstrained Price, the ISO's three reserve markets, summed together, and the ISO's regulation market. For each of the ISO markets that are zonal, the NP15 price was analyzed in detail. Data were used from the opening of the market in 1998 through the end of July 2000.[1]

Analysis of PX Day-Ahead Unconstrained Price

A regression equation was prepared to relate the PX Day-Ahead Unconstrained Price to various factors. A Maximum Likelihood autoregression was used to correct for autocorrelation in the data. The dependent variable was a form of the Incremental Energy Rate (used in QF pricing in California for many years) – the market price divided by the cost of gas. This allows one to separate gas pricing from other issues affecting the supply and price of electricity.

The following logarithmic equation was found (t-statistics here and elsewhere are given below in parentheses:

Ln(PX Unconstrained Price / Weekly Gas Price)[2] =

- 186.027 + 21.4357 * ln(ISO Day-Ahead Forecast Load – FLOAD)
(39.33) (39.31)

- 0.00578 * ln (Day-Ahead Forecast Load – Day-Ahead Scheduled Load – DAUNS – zero
(8.46 if negative

- 0.000149 * FLOAD + 1.37816 *(FLOAD/10000 MW)^2 +
(36.05) (35.63)

+ 0.2756 * Dummy Variable – 1 October and November, 0 other months – OCTNOV
(7.44)

- 0.10389 * Dummy Variable – 1 in 1998, 0 other years – YR98
(3.23)

- 0.23215 * Dummy Variable – 1 in April and May, 1998 – 0 other months – APRMAY98
(4.16)

+ Three 2000 Summer Shift Variables, Dummy Variable for June-July 2000 – SUMM2000 *

+ 0.13177 * ln(FLOAD) - 0.000089 * (FLOAD) + 0.15750 * (FLOAD/10000 MW)^2
(5.22) (5.42) (6.01)

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[1] We acknowledge the fine work of the University of Calfifornia Energy Institute (UCEI), which has put together a data base containing this information.

[2] The gas price variable was the average of high and low weekly gas prices at the California Border from California Energy Markets. The logarithmic variable was set at a minimum of zero, so that the equation would not try to fit logs to negative numbers that would arise in the few hours when prices were less than 1 mill per kWh.

Auto-regressive coefficient 0.9346, Standard error of estimate = 0.1298

Explanation of Regression Results

This equation has a number of factors that make sense in explaining the cost curve. The three load coefficients result in prices that increase more than proportionally with load throughout the range (the coefficient greater than 1 on ln(FLOAD)) and increases even more rapidly in three ranges: between minimum load (about 15,000 MW) and 20,000 MW, as load rises above 30,000 MW and then again above 40,000 MW.

Prices were higher in the months of October and November, when Northwest power is typically scarce, and were lower in 1998, particularly in April and May, when hydro run-off was higher than 1999-2000.

The significance of the day-ahead unscheduled energy variable shows that the PX price is reduced by a few percentage points if energy is not scheduled in the day-ahead market. This has resulted in some of the games of "electric chicken" that have caused large volumes of electricity to be moved out of the PX to be traded at the last minute in the ISO's imbalance market.[3]

The 2000 Summer Shift variables are of key importance, as they show the change in the cost curve. For the same levels of load and the same gas prices, PX day-ahead prices were 10-20% higher in June and July 2000 than in previous months up to 35,000 MW, rising to 40% higher at 40,000 MW and even more at higher load levels. PX day-ahead prices were higher in June and July, 2000 than in previous months. Some increase in prices was observed statistically in May. (See also California PX, 2000.)

Figure 1 shows four representative cost curves.[4] (Figures 1a shows a detailed view below 35,000 MW.)

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[3] A regression relating unscheduled energy to a constant term, load, and two 2000 Summer Shift variables (constant and load) demonstrates that significantly more energy was scheduled at the last minute n the summer of 2000.

[4] A gas price of $2.50/MMBtu was assumed for the first curve, and $5 for the other three curves representing current conditions. The unscheduled energy (DAUNS) variable used at each supply level was the average level from an equation relating DAUNS to total day-ahead forecast loads and a 2000 Summer Shift. Thus unscheduled energy was higher in the summer of 2000, slightly mitigating the PX price. The OCTNOV YR98, and APRMAY98 variables were set to zero to develop the curves.

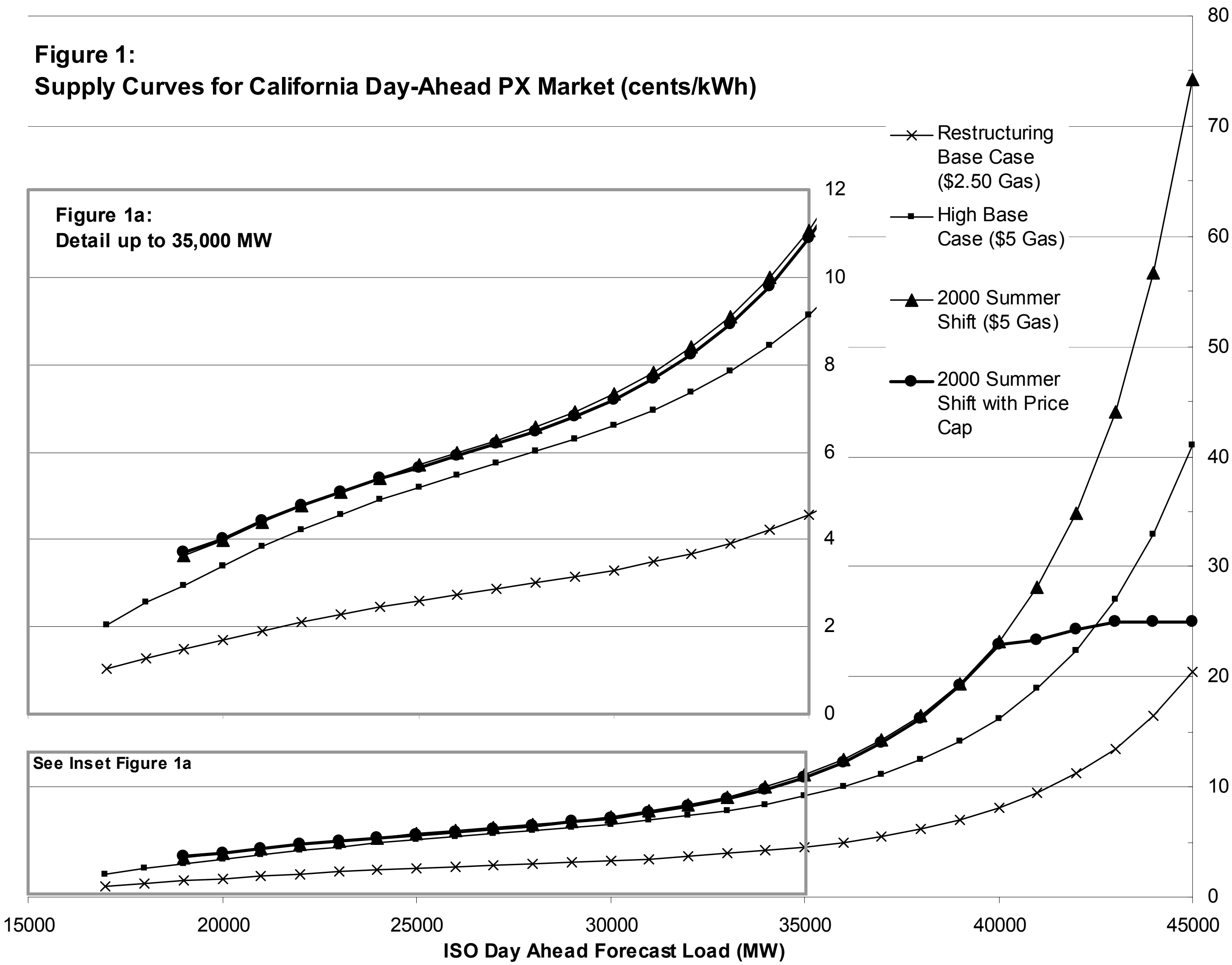

Figure 1:
Supply Curves for California Day-Ahead PX Market (cents/kWh)
Figure 1a:
Detail up to 35,000 MW
See Inset Figure 1a
Restructuring Base Case ($2.50 Gas)
High Base Case ($5 Gas)
2000 Summer Shift ($5 Gas)
2000 Summer Shift with Price Cap
ISO Day Ahead Forecast Load (MW)

The first curve is a $2.50 gas price with the pre-summer-1998 cost curve (Restructuring Base Case). It essentially represents the policy case on which restructuring was based – cheap gas and a cost curve that was not conducive to spikes. Energy cost only 10 mills/kWh at the 17,000 MW load level seen in the middle of the night in the spring, and a 30-mill price was not seen until loads exceeded 28,000 MW. While prices could rise significantly at high load levels, the expected price at 40,000 MW of load (only 5500 MW less than the all-time California peak) was only 8.1 cents/kWh.

The second curve is the same as the first, except with higher gas prices ($5/MMBtu). (Base Case High Gas) The lowest prices are about 22 mills. Prices exceed 5 cents at 25,000 MW, rise to 8 cents at 33,000 MW, and 16 cents at 40,000 MW, topping out in the range of 40 cents/kWh.

The third curve includes the summer shift in the year 2000. (2000 Summer Shift Case) Prices are 10-20% higher than the base cost curve at loads under 30,000 MW. In excess of 30,000 MW, the 2000 Summer Shift prices spiral upwards, reaching 11 cents/kWh at 35,000 MW, and 23 cents/kWh at 40,000 MW. At all load levels summer 2000 prices were double those of the halcyon days of only two years earlier, and prices were over 250% of 1998 levels in the relatively typical summer peak range of 35,000-40,000 MW (without even considering extreme peaks).

The fourth curve is based on the 25-cent price cap adopted by the ISO after the analysis period closed on July 31, 2000. It is discussed further below.

Effect of Price Caps on the PX Day-Ahead Price

A second regression was run to show the impact of price caps. It used the same functional form, except that the dependent variable had the price capped at $250/MWh, and discontinuous variables were included for loads above 40,000 MW to reflect the impact of caps at high load levels.

Ln(PX Unconstrained Price / Weekly Gas Price)[5] =

- 184.093 + 21.2064 * ln(FLOAD) - 0.00576 * ln (DAUNS)
(35.00) (34.91) (8.50)

- 0.000147 * FLOAD + 1.35334 *(FLOAD/10000 MW)^2
(31.47) (30.59)

+ 0.000028 * (FLOAD-40000 MW zero if negative)
(2.51)

+ 0.2764 * OCTNOV – 0.10371 * YR98 - .23256 * APRMAY98
(7.44) (3.29) (4.25)

+ Four 2000 Summer Shift Variables,

SUMM2000 * (+ 0.16338 * ln(FLOAD) - 0.000011 * (FLOAD)
(5.92) (6.05)

+ 0.1918 * (FLOAD/10000 MW)^2 – 0.000021 * (FLOAD-40000MW)
(6.43) (11.32)

Auto-regressive coefficient 0.9338, Standard error of estimate = 0.1289

The equation is very similar to the original equation except for the Summer Shift variables. The application of a cap reduces the upward shift for the summer of 2000 and in fact reverses it above 40,000 MW, as shown on Figure 1. The capped prices not only fall far below the shifted cost curve but cross the High base case ($5 gas) cost curve at about 42,000 MW.

This capped energy price curve closely tracks the Summer 2000 curve up to 35,000 MW and then shifts downward, peaking, as expected, in the $250/MWh range.

Analysis of ISO Imbalance Market Prices

The ISO imbalance market price regression (for NP15) was in a very similar form to that for the Day-Ahead PX market, although a few extra variables proved significant. The loads were measured in terms of the ISO's Actual loads rather than its Day-Ahead forecast (used for day-ahead PX prices).

[5] The gas price variable was the average of high and low weekly gas prices at the California Border from California Energy Markets. The logarithmic variable was set at a minimum of zero, so that the equation would not try to fit logs to negative numbers that would arise in the few hours when prices were less than 1 mill per kWh, thus giving too much weight to those few hours.

Ln(ISO Imbalance Price / Weekly Gas Price) =

- 120.412 + 13.9116 * ln(ISO Actual load -- ALOAD) – 0.00099 * ALOAD
(6.60) (6.62) (6.35)

+ 1.00879* (ALOAD/10000MW)^2
(7.05)

+ 0.02442 * LN(ALOAD-dayahead scheduled load, zero if negative -- DIFF)
(8.98)

+ 0.65774 * OCTNOV – 0.10286 * YR98 – 0.46577 * APRMAY98
(18.87) (3.60) (9.01)

+ three 2000 Summer Shift variables

SUMM2000 * (0.5122 * ln(ALOAD) - 0.00032 * (ALOAD) + 0.4992 * (ALOAD/10000 MW^2
(5.74) (5.46) (5.26)

+ two time of day variables

- 0.16796 * Dummy variable 1 if weekday – WKDAY
(6.70)

+0.06091 * Dummy variable 1 if hour ending before 6 am -- EARLYAM
(3.32)

Auto-regressive coefficient 0.6840, Standard error of estimate = 0.5394

The regression analysis shows a more volatile cost curve than the PX price, with lower prices at the low end and higher prices at the high end. The difference between the actual load and day-ahead scheduled load was significant and positive. The somewhat lower prices in the PX day-ahead market caused by unscheduled load are offset by higher prices in the ISO imbalance market.[6] Two time-of-day variables are significant that were not significant in the PX market. The negative WKDAY variable, although apparently counter-intuitive, reflects that the ISO imbalance market can only receive generation from units that are committed and running, and some thermal units are turned off over the weekend for economic reasons, thus making the weekend market thinner at any given load level.

Figure 2 shows the ISO imbalance market results. A reliable capped equation could not be estimated. Figure 3 compares those results to the PX market. The ISO day-ahead price is less than the PX price at load levels up to 40,000 MW. Above 40,000 MW, it is much higher, particularly after the 2000 Summer Shift.

[6] The California PX found this result in its analysis of summer 2000 prices. (California PX, 2000)

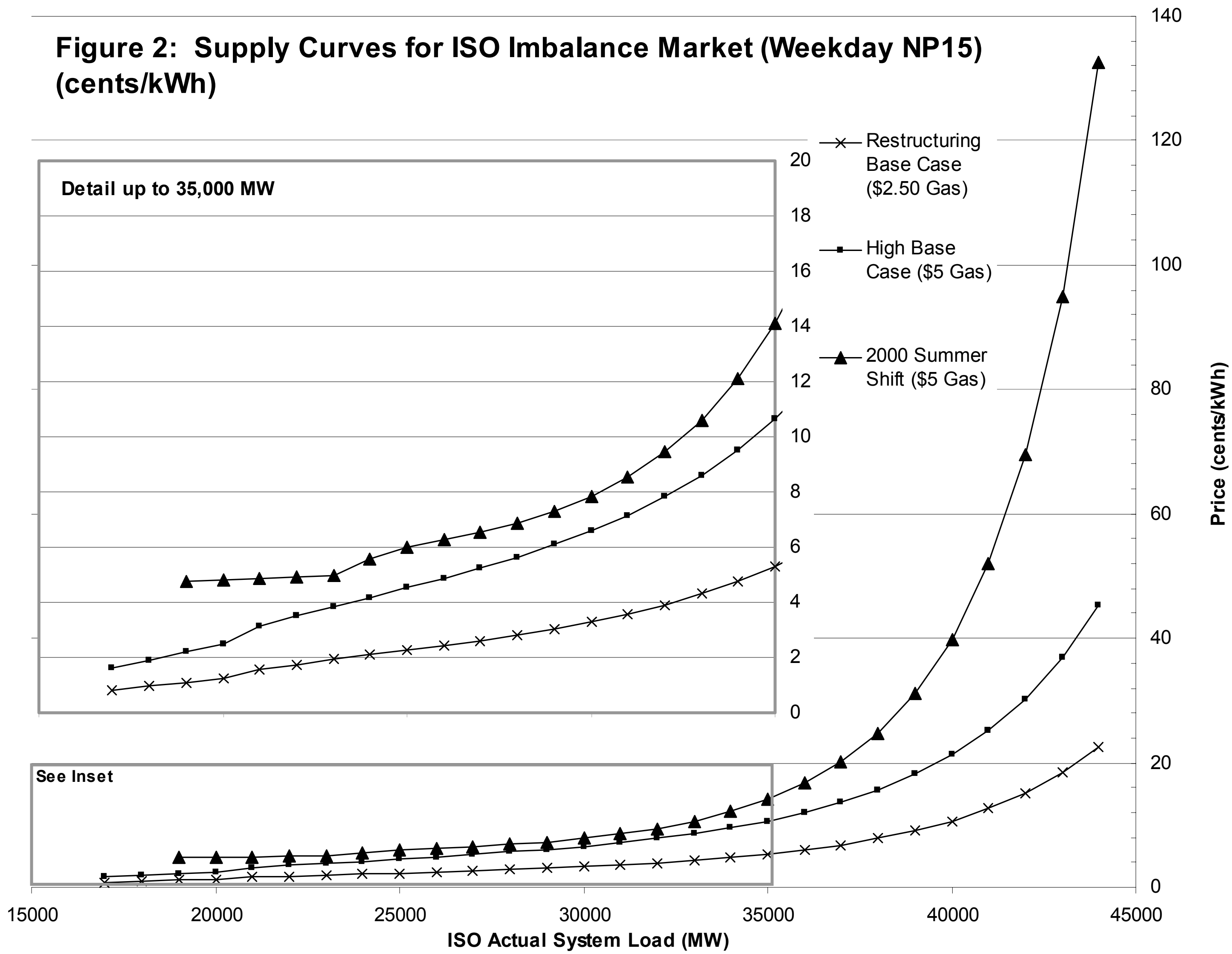
Figure 2: Supply Curves for ISO Imbalance Market (Weekday NP15) (cents/kWh)
Detail up to 35,000 MW
See Inset
Restructuring Base Case ($2.50 Gas)
High Base Case ($5 Gas)
2000 Summer Shift ($5 Gas)
Price (cents/kWh)
ISO Actual System Load (MW)
0
2
4
6
8
10
12
14
16
18
20
0
20
40
60
80
100
120
140
15000
20000
25000
30000
35000
40000
45000

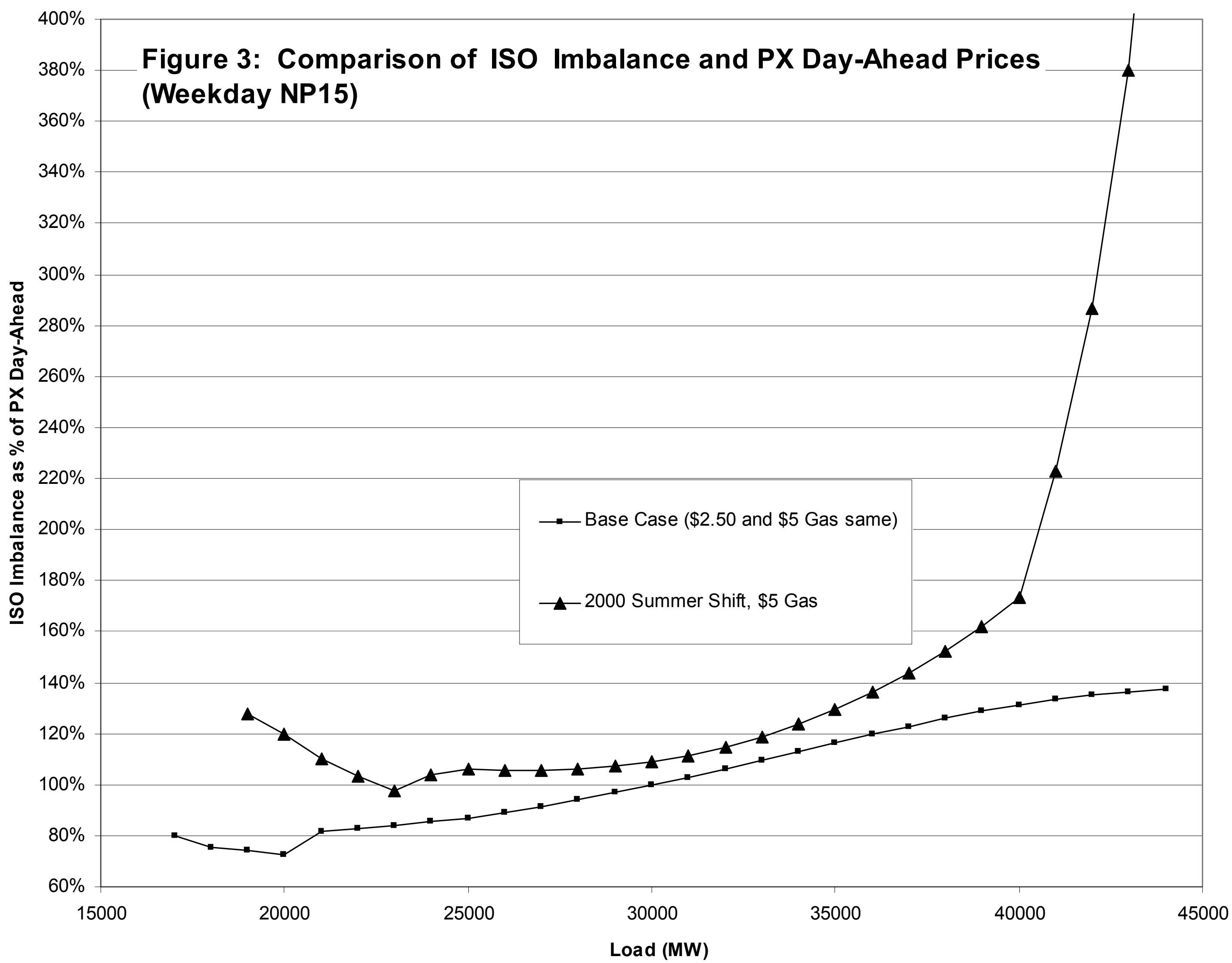
Figure 3: Comparison of ISO Imbalance and PX Day-Ahead Prices (Weekday NP15)
400%
380%
360%
340%
320%
300%
280%
260%
240%
220%
200%
180%
160%
140%
120%
100%
80%
60%
ISO Imbalance as % of PX Day-Ahead
15000
20000
25000
30000
35000
40000
45000
Load (MW)
Base Case ($2.50 and $5 Gas same)
2000 Summer Shift, $5 Gas

Analysis of Ancillary Services

Ancillary Services prices (for reserves) were modeled under the theory that (at least at high load levels) the price of reserves converges to the profit margin (price minus immediately variable fuel cost) for commodity energy,[7] while at lower load levels, these prices are low because of the ability to supply reserves with partially loaded thermal units, hydro that is storing water, and cheap combustion turbine capacity standing idle.

Therefore, these prices were modeled using similar variables to commodity energy, but the findings were quite different.

Reserves

All reserve costs (spinning, non-spinning, and replacement, but excluding regulation) were added together (based on the total quantity of each kind of reserves multiplied by its NP15 zonal price) and divided by the ISO day-ahead forecast of kWh to develop a metric for analysis.

This method of analysis does not distinguish between two separate factors that raise the costs of reserves: (1) that the quantity of reserves increases as load rises, and (2) that the price per megawatt of reserves purchases increases as load increases.

The following regression was run. Data for the period prior to June 11, 1998 was excluded, because most market participants did not have authority to use market-based pricing, and data were capped at $750 per MW-hour to reflect that higher price spikes in the summer of 1998 are non-recurring. (see Earle et al. 1999)

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[7] Earle et al., 2000, p. 70. Hirst, 2000.

Ln(Reserve Cost per kWh) =

15.5084 - 3.3916 * ln(FLOAD) + 1.2952 * LN (ALOAD)
(6.24) (9.20) (4.69)

+ 0.41460 * (FLOAD/10000MW)^2 - 0.2964 * OCTNOV + 0.87753 * YEAR98
(23.09) (3.43) (12.39)

- 0.04630 * ln(FLOAD) * Dummy Variable for Rational Buyer Program (zero
(5.85) after institution of program starting 11/1/1999, zero before -- RATLBUY)

+ 0.7323* ln(GASPRICE) - 0.4405 * Dummy variable 1 in hrs. 1-6 and 23-24, 0 others– HR23TO6
(4.33) (24.69)

+ 0.08365 * Dummy variable 1 on weekends, zero weekdays -- WKEND
(1.97)

+ One 2000 summer shift variable:

SUMM2000 * 0.06748 * (FLOAD/10000MW)^2]
(6.08)

Auto-regressive coefficient = 0.8544 Standard error = 0.5699

The variables show rapid price increases as load increases and a strong 2000 Summer Shift upward as load increases consistent with increases in energy prices and (theoretically) energy profit margins. Both actual and forecast loads were significant, as reserves are bought in both day-ahead and hour-ahead markets. The variables for YEAR98 and the Rational Buyer Program reflect changes by the ISO in market design that significantly reduced the cost of reserves. The reserve market, like the ISO energy market, features some timing quirks, with low costs in the early morning (when many units are on line overnight to provide energy the next day, and higher costs on weekends (when less economic thermal units are pulled out of service, so fewer units are available to provide reserves).

Effect of Price Cap on Reserves Market

With a market cap of $250/MWh in each of the reserve markets, another regression was run:

ln(Reserve Cost per kWh – each market capped at $250/MW-hour) = **16.6571+ -3.5584 * ln(FLOAD) + 1.3399 * LN (ALOAD) - 0.00014 * (fLOAD-40000MW)** **(6.47) (9.53) (4.89) (4.00)** **+ 0.42499 * (FLOAD/10000MW)^2 - 0.2950 * OCTNOV** **(22.53) (3.42)** **+ 0.8801 * YEAR98 - 0.4618* ln(FLOAD) * RATLBUY** **(12.47) (5.86)** **+ 0.75509* ln(GASPRICE) - 0.44049* HR23TO6 + 0.08467 * WKEND** **(4.49) (24.86) (2.00)** **+ One 2000 summer shift variable:** **SUMM2000 * 0.05807 * (ALOAD/10000MW)^2** **(5.25)** **Auto-regressive coefficient = 0.8549 Standard error = 0.5661**

Again, the capped model was similar to the uncapped except for the discontinuous variables over 40,000 MW that implement the cap.

Regulation

The regulation market is more expensive than the reserve market at low load levels, because real fuel- and efficiency-related costs can set a floor on the price, there is a need to have more regulation during some relatively low load hours (such as 6-7am and 10-11 pm), and the supply of regulation may be lower during those hours, because it interferes with generator ramping.[8] Prices are very different in the daytime (8am-10pm) and overnight hours (10pm-8am). A regression was run in total cost dollars (NP-15 price multiplied by total quantity), because the amount of regulation is less sensitive to load than the amount of reserves, resulting in falling costs per kWh of load from very low load levels through about 30,000 MW. [9]

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[8] Earle et al. (2000) provide information on the hourly price of regulation per unit of regulation provided that support the latter contention.

[9] The modeling of this relationship using discontinuous variables was necessary, as other forms (polynomial, logarithmic, exponential, could not capture the high prices above 40,000 MW without skewing the results for lower load levels).

Ln (regulation total dollars) =

7.5938 + 0.0001288 * (FLOAD) - 0.15821 * (FLOAD/10000MW) ^2
(21.84) (4.92) (3.21)

+ 0.7176 * OCTNOV – 0.6316 * RATLBUY + One 2000 Summer Shift variable:
(6.89) (8.80)

SUMM2000 * [0.0000995*(FLOAD/10000MW)^2 +0.57165 * HR22TO8
(11.37) (25.15)

Auto-Regressive Coefficient 0.8369 Standard error = 0.7101

The most critical element of this equation is the higher cost in total dollars as loads are being ramped up and down at night, reducing the availability of generation to provide regulation. Prior to the 2000 Summer Shift, costs for regulation were relatively flat in cents per kWh of total load. The quantity of regulation does not rise as fast as load, but its cost rises as an opportunity cost. The rational buyer program reduced costs of regulation. The Summer Shift raised costs at all load levels, but particularly in the highest load levels. A capped equation could not be reliably estimated.

Summary Overview of Reserve and Regulation Markets

In essence, as shown in Figure 4, the reserve market does not impose significant costs in most of the hours of the year. Prices associated with low gas prices (after implementation of the rational buyer reforms but before the 2000 Summer Shift) could be expected to average less than $1 per MWh (of total load) up to 38,000 MW and with a peak cost averaging only $5 per MWh of total load at the highest load levels. Higher gas prices (without the summer shift) raised these costs to $1/MWh at 36,000 MW and $8 at the top of the peak. The 2000 Summer Shift greatly increased prices in the peak portion of the reserve and regulation markets, with total costs of reserves and regulation averaging $1 at 25,000 MW, $3 at 35,000 MW, $10 at 41,000 MW, and as much as $35 per MWh at peak, but even these prices are far below the energy market prices. Capping the market price has the effect of reducing the rate of increase of prices above 40,000 MW to a maximum price of less than $20/MWh.

Nevertheless, the theoretical implications of these rapidly rising reserve market prices suggest that profits in the energy market have been increasing after the 2000 Summer Shift.

Figure 5 compares ancillary service costs to energy costs. In the Restructuring Base Case, reserves and regulation cost about 3% of energy costs at low load levels, falling below 1.5% at about 30,000 MW (because of the fixed nature of regulation costs up to 30,000 MW), and then rising back to slightly over 3% of energy costs under peak conditions. In the High Gas Base Case, reserve costs were actually lower as a percentage of energy costs. The 2000 Summer Shift resulted in a percentage increase of reserve costs to 2% at low load levels, rising steadily to 3% at 35,000 MW, and then rising rapidly, particularly above 40,000 MW, to reach 8% of energy costs at the top of the peak.

Nevertheless, the theoretical implications of these rapidly rising reserve market prices suggest that profits in the energy market have been increasing after the 2000 Summer Shift.

Summary of Cost Curves

Figure 6 integrates all of the analysis for PX prices and ancillary services, showing a cost curve that is the sum of PX Day-Ahead energy plus weekday NP-15 ancillary services costs expressed in cents per kWh.

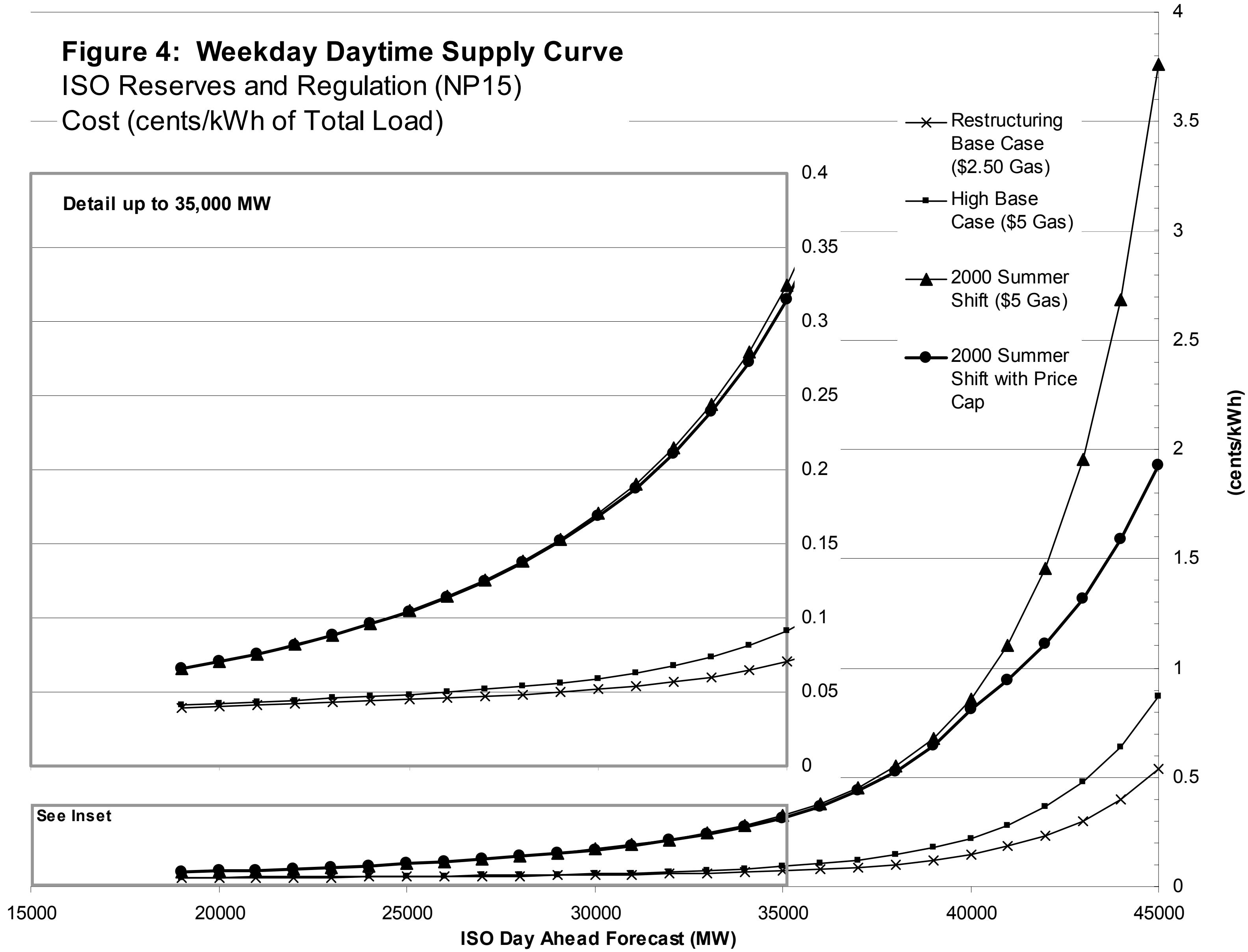
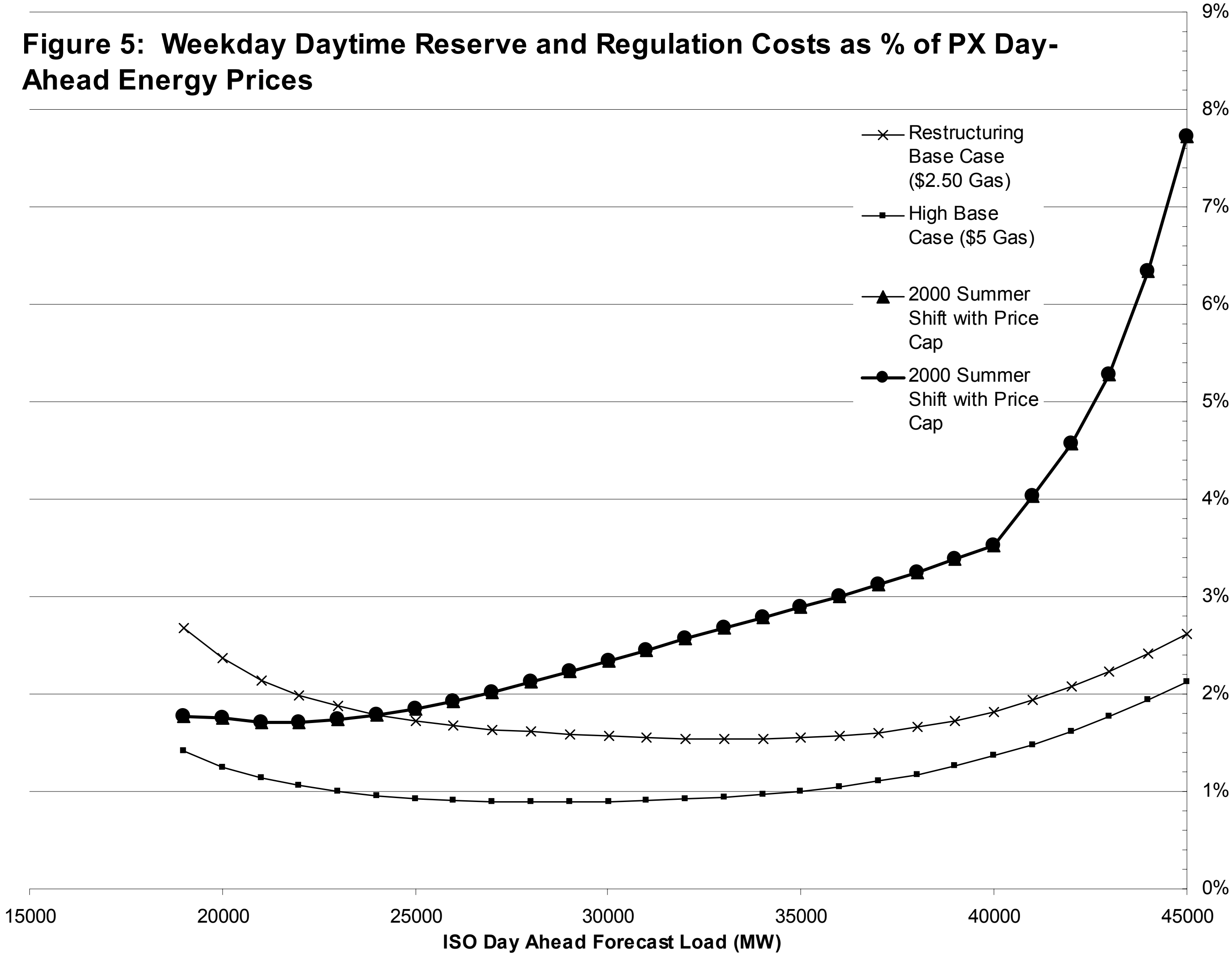


Figure 4: Weekday Daytime Supply Curve
ISO Reserves and Regulation (NP15)
Cost (cents/kWh of Total Load)
Detail up to 35,000 MW
See Inset
Restructuring Base Case ($2.50 Gas)
High Base Case ($5 Gas)
2000 Summer Shift ($5 Gas)
2000 Summer Shift with Price Cap
(cents/kWh)
ISO Day Ahead Forecast (MW)
15000
20000
25000
30000
35000
40000
45000
0
0.5
1
1.5
2
2.5
3
3.5
4
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0.4

Figure 5: Weekday Daytime Reserve and Regulation Costs as % of PX Day-Ahead Energy Prices



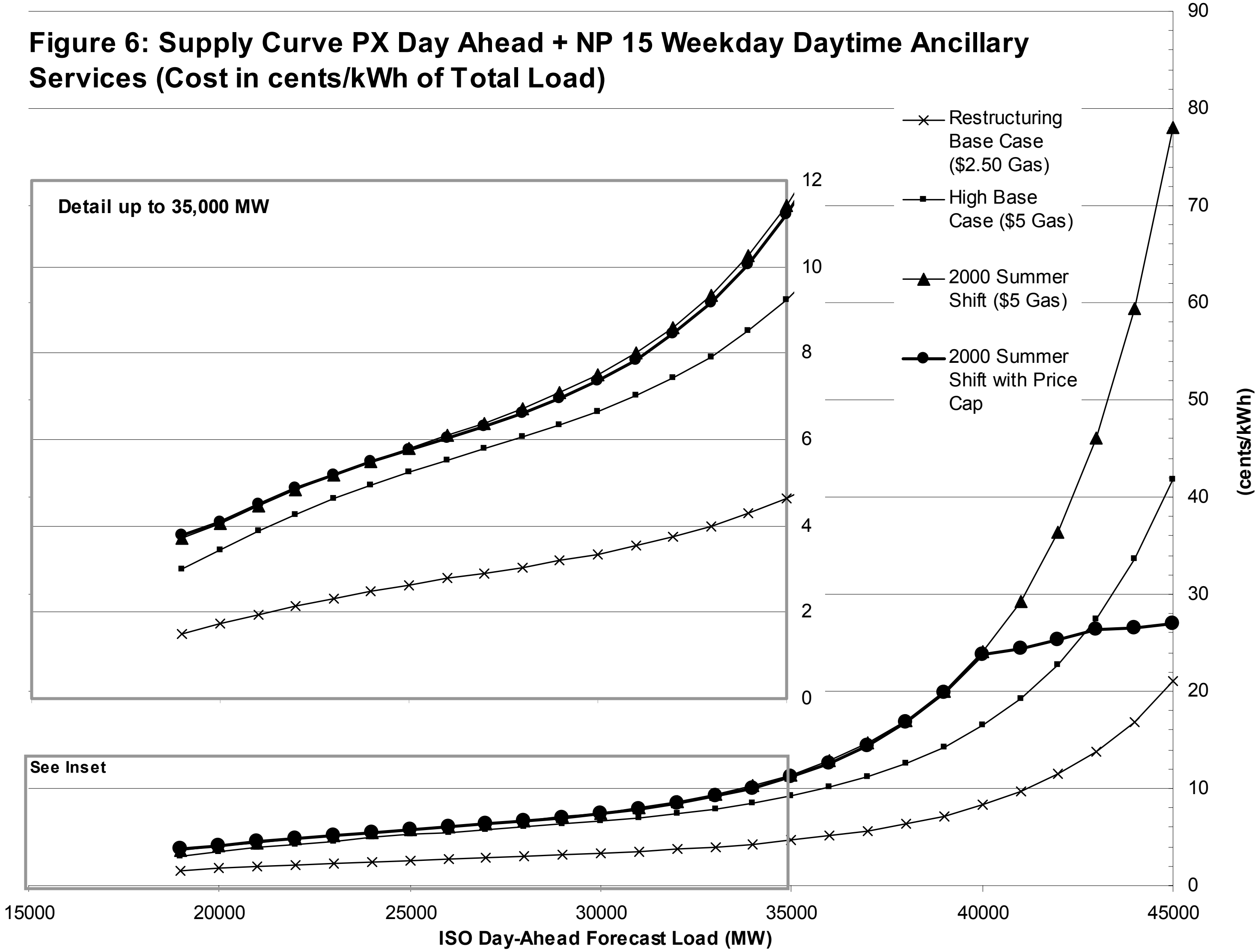


Figure 6: Supply Curve PX Day Ahead + NP 15 Weekday Daytime Ancillary Services (Cost in cents/kWh of Total Load)
Detail up to 35,000 MW
See Inset
Restructuring Base Case ($2.50 Gas)
High Base Case ($5 Gas)
2000 Summer Shift ($5 Gas)
2000 Summer Shift with Price Cap
ISO Day-Ahead Forecast Load (MW)
(cents/kWh)
15000
20000
25000
30000
35000
40000
45000
0
10
20
30
40
50
60
70
80
90
0
2
4
6
8
10
12

VALUE OF LOAD REDUCTION AND ENERGY CONSERVATION

Introduction

In addition to the direct cost of energy prices, load reduction, energy conservation, and distributed generation all have a significant value in reducing the overall system cost of electricity.

In the old world, in a given hour the marginal cost of energy of a bundled utility was the price of the last most expensive unit of the utility's generation. But the cost was only incurred for that last unit. Thus, the marginal cost was the value of demand reduction, because the last unit's generation was avoided.

In the new world of power pools, the price for all units of energy traded through the pool is set on an hourly basis by the market-clearing bid price for the last unit (of generation or load reduction) bid in to serve demand. As demand rises, the total revenue received by all generators rises. Thus the value of demand reduction is not just the market price (bid price of the last unit). It is the market price plus the increase in the bid price multiplied by all other generators except the last unit.

As demand rises, particularly in peak periods, the price of energy rises relatively rapidly. If demand can be reduced, the price will fall along with it, benefiting not only the customer whose demand is reduced but all other customers who receive the lower prices of spot market energy.

This effect was first pointed out quantitatively by Rich Ferguson of the Center for Energy Efficiency and Renewable Technologies (Ferguson, 1999). This issue was further analyzed, using data through mid-1999, by Marcus (2000) in testimony opposing fixed customer charges in a San Diego Gas and Electric Company rate design case.

However, the much higher prices observed in 2000, and particularly the Summer Shift, give new urgency to this concept.

The California ISO recognizes that the lack of demand responsiveness by customers has an impact on price performance in the California market, (Wojak et al, 2000) although it is largely considering real-time responses rather than investments to reduce demand at all load levels.

How Hedging of Power Prices Affects the Results

To review this issue further, we must consider the impact of hedging the short-term market price. There are two different kinds of hedges – physical hedges and contractual hedges. Under a physical hedge, the utility owns a plant which delivers power under a price based generally on a cost of service approach and gives the preponderance of excess revenue earned in the market to ratepayers. Examples of this approach are the proposal to retain Edison's hydro within the utility, and proposals both to retain PG&E's hydro within the utility and to allow its divestiture to an affiliate under conditions that a 40-year contract share the preponderance of the difference between a cost estimate and market prices with ratepayers. The 50-50 sharing of profits from Diablo Canyon, San Onofre, and Palo Verde nuclear plants after the end of the restructuring period provide a partial but not complete physical hedge. Contractual hedges, by contrast, are market-based prices. Theoretically, these hedges are based on expectations of future market prices plus an insurance premium. Economic theory suggests that the pricing of contractual hedges are based on all information available to the participants in those hedges regarding future market trends.

As a result, we now conclude that the value of demand reduction in reducing prices applies to contractual hedges but not to physical hedges.

If PG&E and Edison were to retain all of their hydro and nuclear generation (plus the Four Corners coal plant for Edison), they would be approximately 40% physically hedged.[10] As a result, we analyze a case where price reduction applies to 60% of generation, as well as 100%. The former case appears more consistent with recent policy positions taken by consumers in California;[11] the latter reflects the divestiture of nearly all generation in the long run.

Figure 7 compares the value of a 5% reduction in energy use from all load levels to the market price including both energy and ancillary services costs, with no physical hedging. It shows that, including the impact on the market price, the value of load reduction is at least 200% of the value of energy at all loads. Above 30,000 MW, both prices and the value of conserved energy rise rapidly, but the value of load reduction rises faster. Under the Base cost curve, it rose from 220% to 550% of the market price of energy from 30,000 to 40,000 MW and then rose faster to reach almost 10 times the market price at 45,000 MW. The 2000 Summer Shift dramatically increased the value of load reduction above 30,000 MW. the value of load reduction rose from 250% to 610% of the market price of energy from 30,000 to 40,000 MW and then rose faster to reach almost 10 times the market price at 45,000 MW. Capping reduces the value of load reduction in excess of 40,000 MW. Nevertheless, the other consequences of price caps (shortages, exports, etc.) suggest that a high value should continue to be assumed.

Figure 8 provides the same information as Figure 7, but with 40% physical hedging. The value of load reduction is 170% to 220% of the market price at load levels up to 30,000 MW, rising (under Summer 2000 Shift) from 192% to 432% of the market price between 30,000 and 40,000 MW and to 6 times the market price at a high peak.

[10] A further analysis could break this down by time period.

[11] See The Utility Reform Network (2000).

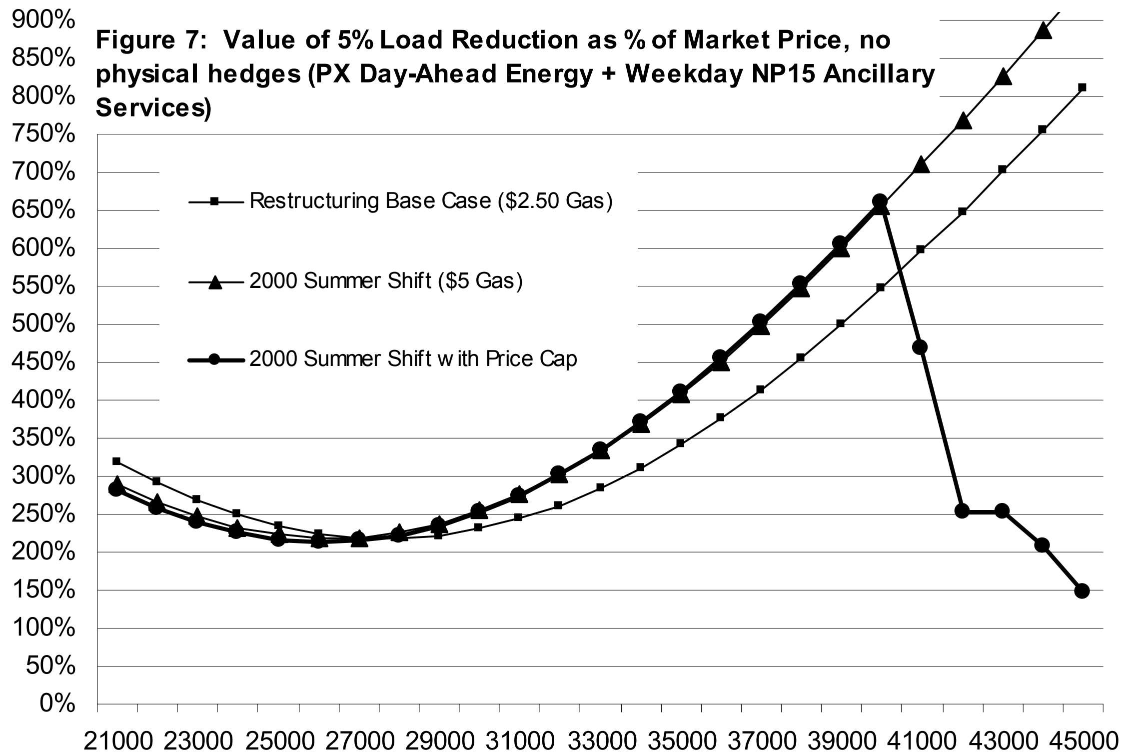


Figure 7: Value of 5% Load Reduction as % of Market Price, no physical hedges (PX Day-Ahead Energy + Weekday NP15 Ancillary Services)
Restructuring Base Case ($2.50 Gas)
2000 Summer Shift ($5 Gas)
2000 Summer Shift with Price Cap
900%
850%
800%
750%
700%
650%
600%
550%
500%
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
21000 23000 25000 27000 29000 31000 33000 35000 37000 39000 41000 43000 45000

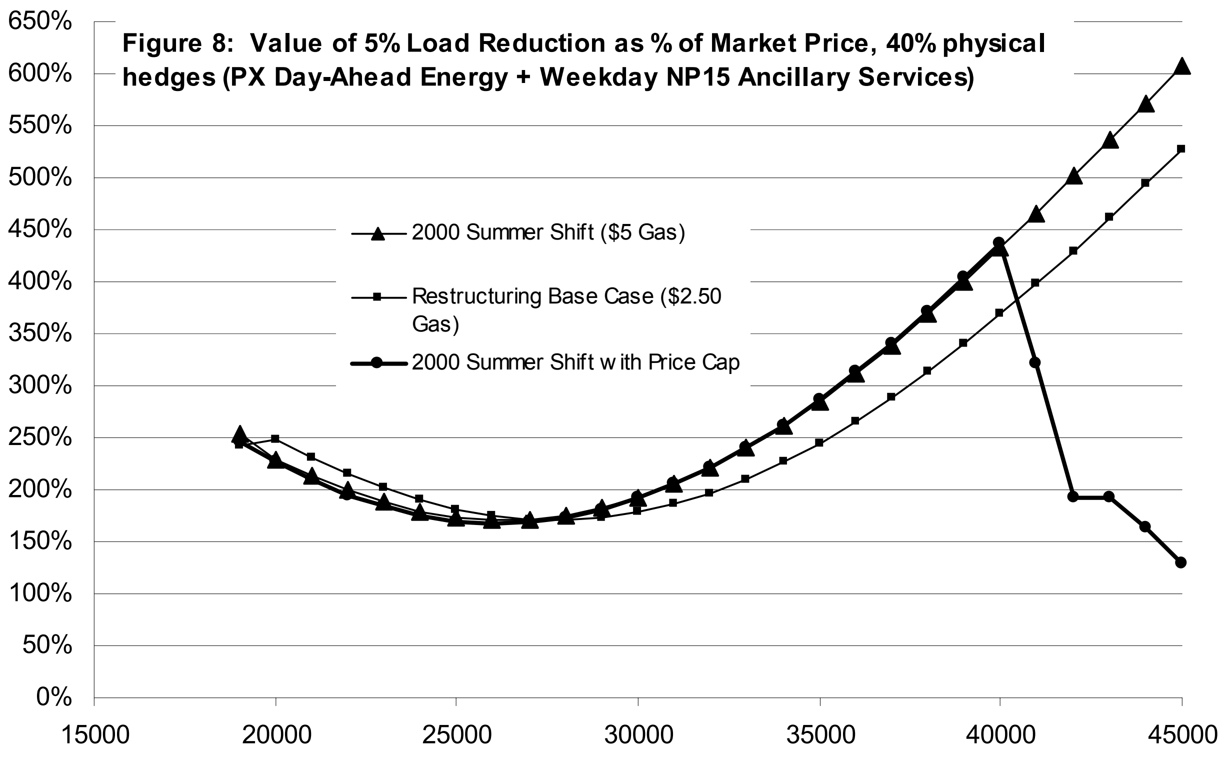


Figure 8: Value of 5% Load Reduction as % of Market Price, 40% physical hedges (PX Day-Ahead Energy + Weekday NP15 Ancillary Services)
2000 Summer Shift ($5 Gas)
Restructuring Base Case ($2.50 Gas)
2000 Summer Shift with Price Cap
650%
600%
550%
500%
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
15000 20000 25000 30000 35000 40000 45000

In the Summer 2000 Capped case with no hedges, (Figure 9) the value of load reduction starts near 12 cents/kWh in the vicinity of 20,000 MW (with a 3.6 cent market price). The value of load reduction rises to 18 cents at 30,000 MW (with a 7.2 cent market price). It increases to 45 cents per kWh at 35,000 MW (with an 10.9 cent market price), and fluctuates between 50 cents and $1.60 per kWh (due to the price cap) above 35,000 MW. The cap causes the value of conserved energy to fall at the highest load levels. The capped market price rises to slightly over 25 cents at the highest peak loads including both energy and ancillary services.

In the Summer 2000 Capped case with a 40% physical hedge (also shown in Figure 9). The value of conserved energy starts in the 9 cent range, rising to 14 cents at 30,000 MW, to 32 cents/kWh at 35 cents, and fluctuates between 35 cents and $1.00 per kWh at the highest load levels due to the price cap. These amounts are still considerably higher than market price, despite the 40% hedge.

Table 1 below extracts similar information for all four cases, with no hedge and a 40% physical hedge.

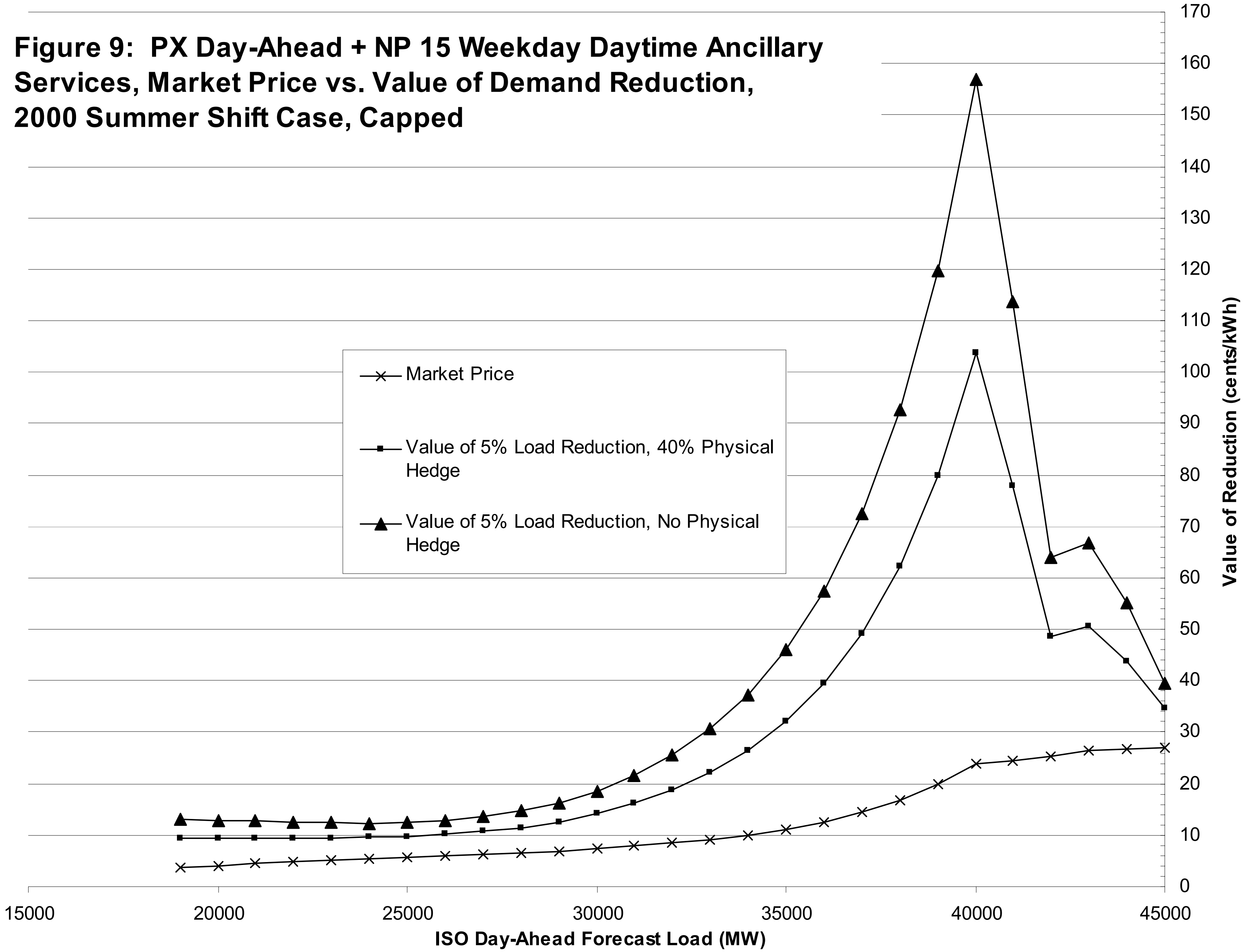


Figure 9: PX Day-Ahead + NP 15 Weekday Daytime Ancillary Services, Market Price vs. Value of Demand Reduction, 2000 Summer Shift Case, Capped
Market Price
Value of 5% Load Reduction, 40% Physical Hedge
Value of 5% Load Reduction, No Physical Hedge
Value of Reduction (cents/kWh)
ISO Day-Ahead Forecast Load (MW)
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
15000
20000
25000
30000
35000
40000
45000

Table 1: Comparison of Market Price of Power and Value of a 5% Load Reduction for Various Load Levels and Cost Curve Scenarios (cents per kWh)

No physical hedge

	Restructuring Base Case $2.50 Gas		Base Cost Curve $5 Gas		2000 Summer Shift $5 Gas		2000 Summer Shift Capped $5 Gas	
MW forecast	Market Price	Load Reduction Value	Market Price	Load Reduction Value	Market Price	Load Reduction Value	Market Price	Load Reduction Value
20,000	1.7	6.0	3.4	12.0	4.0	12.8	4.1	12.8
25,000	2.6	6.2	5.2	12.3	5.8	12.9	5.8	12.6
30,000	3.4	7.7	6.7	15.4	7.5	19.1	7.4	18.6
35,000	4.6	15.8	9.2	31.6	11.4	46.5	11.2	46.0
40,000	8.3	45.2	16.5	90.1	24.0	157.1	23.8	156.9
45,000	21.0	170.6	41.8	339.4	78.1	738.5	26.9	39.6

40% Physical Hedge

	Restructuring Base Case $2.50 Gas		Base Cost Curve $5 Gas		2000 Summer Shift $5 Gas		2000 Summer Shift Capped $5 Gas	
MW forecast	Market Price	Load Reduction Value	Market Price	Load Reduction Value	Market Price	Load Reduction Value	Market Price	Load Reduction Value
20,000	1.7	4.3	3.4	8.6	4.0	9.3	4.1	9.3
25,000	2.6	4.8	5.2	9.5	5.8	10.1	5.8	9.8
30,000	3.4	6.0	6.7	11.9	7.5	14.4	7.4	14.1
35,000	4.6	11.5	9.2	22.6	11.4	32.5	11.2	32.1
40,000	8.3	30.4	16.5	60.7	24.0	103.9	23.8	103.6
45,000	21.0	110.8	41.8	220.4	78.1	474.4	26.9	34.5

This information runs counter to conventional wisdom. Energy efficiency and distributed generation is no longer a breeder of rate increases. At all load levels, the potential for rate increases is greatly mitigated by the reduced commodity prices for everyone that result from reducing load. Conservation in peak hours, by all customers, but most particularly by load profiled residential and commercial customers, can provide major rate savings.

Energy efficiency is of critical importance now, but it is not just a way to get through a crunch of tight supply and high gas prices. Even in the "good-old-days" scenario of \$2.50 gas and no Summer Shift and with a 40% physical hedge, energy efficiency would still be worth at least 4 cents per kWh in the deepest off-peak, 6 cents per kWh in typical mid-peak periods, 6-12 cents from 30,000 to 35,000 MW, and 12-30 cents from 35,000-40,000 MW, rising drastically above 40,000 MW.

The analysis shown above does not mean that all of the numbers calculated from this particular cost curve will remain correct if the cost curve shifts again (e.g., because of the addition of new generators). However, the analysis demonstrates the reasonableness of the concept– **that demand reduction has a value to society on the order of more than twice the market price of power during most hours of the year, and that it rises to being four to eight times as valuable as the (increased) market price during the 10% of hours closest to the peak (unless reduced by a price cap).**

The shape of the curve depends on the specifics of supply, demand, and market power of the system. However, the fact that conservation is worth more than the market price is structural – based on the workings of the new market.

Thus, the data demonstrate that the market price by itself does not represent the full value of energy conservation, distributed generation, and load reduction. The contention of Shimon Awerbuch (2000) that society would be better off with price signals such as customer charges that encourage purchase of more kilowatt-hours and fewer energy-saving devices ignores this significant financial externality. Similarly, economists at the California Energy Commission [for example, Goeke (1996)] who contend that market price signals by themselves will necessarily result in economically efficient levels of conservation and consumption for society (thus proposing the combination of time-of-use meters to send price signals and flat customer charges to recover distribution rates) have also failed to recognize that externality.

CONCLUSION

This analysis shows two critical facts. First, the Summer of 2000 was different than the two previous years of operation of the California power market. We cannot explain the price explosion with reference to the failure to build powerplants in California or the spike in gas prices. This problem is not caused by the usual suspects. We cannot stop by asking what California expects after a decade of not building powerplants and after a gas price run-up. These issues have had a significant effect on prices. That effect can be seen by comparing the Base Case High Gas cost curve to the Restructuring Base Case cost curve), and considering higher average levels of demand in 2000 than in 1999, as shown on Table 2 below.

Table 2
June and July Loads, 2000 vs. 1999

	Average Load (MW)		Hours over 35,000 MW	
	ISO Day-Ahead	ISO Actual	ISO Day-Ahead	ISO Actual
2000	30003	29737	356	323
1999	27897	27762	168	139
Growth	7.54%	7.11%	112%	132%

But these phenomena do not tell the story of the 2000 Summer Shift. A significant price increase remains in Summer 2000 after controlling for both the level of demand and the level of gas prices. Possible explanations for the 2000 Summer Shift are beyond the scope of this analysis,[12] but could be a combination of relatively unpleasant but somewhat mundane and explainable phenomena (higher demand outside California raising prices in California, higher costs of RECLAIM pollution credits, etc.) to more sinister practices (gaming of markets taken to a new level). The point that this analysis shows is that the summer 2000 prices cannot be dismissed as an expected market outcome. It needs further investigation.

Second, the value of load reduction (in reducing the prices paid by everyone) is at least twice as great as the market prices themselves, and it rises dramatically as load increases. It is clearly in the best interest of society to spend money and send price signals beyond the market price to encourage energy efficiency and load shifting, particularly during the summer peak. Distributed photovoltaic generation, with its relatively strong correlation with peak loads, (JBS Energy, 1996) could be particularly important in this regard. This finding that conservation not only benefits the conserver but everyone else should become the cornerstone of a new public goods imperative and the associated rate design policy.

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[12] Recent analysis of the is issue is contained in California PX, 2000 and Wojak et. al., 2000. Some of the items mentioned here (RECLAIM, supply conditions in the rest of the west) are also referenced in these reports. Siddiqui et al. (2000) provides evidence of the existence of market power based on analysis of the California ancillary services markets.

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