Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market

March 2001

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Executive Summary

This report provides the results of additional analyses undertaken by the California Independent System Operator Corporation's Department of Market Analysis ("DMA") of the exercise and impact of market power in California's wholesale energy markets.

First, additional analysis of the impact of market power on overall system prices is presented based on the price cost markup.[1] In this analysis, the potential impacts of NOx emissions costs and hours of potential resource scarcity are explicitly incorporated into the analysis. Results show that after incorporating potential NOx costs and hours of resource scarcity into the analysis, over 30% of wholesale energy costs over the last year can be attributed to market power, or a level that clearly exceeds the range that may be consistent with a workably competitive market. The results clearly show that market power not limited to hours when a deficiency in operating reserves requires the ISO to declare the existence of a System Emergency. The resulting prices represent potential additional net costs to consumers of about $6.8 billion. About 80% of these additional costs are attributable to non-emergency hours when the ISO has not declared Stage 3 conditions.

Second, wholesale prices are examined in relation to the cost of investment in new supply. Regulators and others have expressed concern that prices be sufficient to make investments in new supply profitable, so that the entry of additional supply is encouraged. Results of this analysis indicate prices over the last 12 months have significantly exceeded the cost of new supply options. On an annualized basis, wholesale energy prices since January 2000 are exceed the cost necessary for new investment by about 400%, and would allow recovery of an investment in new supply in a period of just over one year. Thus, this analysis indicates that any market power mitigation plan that is adopted on a going forward basis may be designed to reduce significantly wholesale prices observed over the last year, while still providing sufficient opportunity for recovery of costs in new investment.

[1] See Comments of the ISO on Nov. 1 Order, Appendix A, November 22, 2000. Results of this analysis are consistent with other filings at FERC based on the price cost markup, including "Diagnosing Market Power in California's Restructured Electricity Markets", (Borenstein, Bushnell, and Wolak), August 2000; Updated results through June 2000 presented in *An Analysis of the June 200 Price Spikes in the California ISO's Energy and Ancillary Service Markets*, MSC Report, September 6, 2000); and Joskow/Kahn.

1. Background

Previous DMA analyses have shown that the high prices observed since May 2000 have been due to the exercise of market power, in combination with several other underlying drivers of that would be expected to increase costs even under perfectly competitive conditions. DMA has developed and presented analyses specifically designed to differentiate between market costs incurred as a result of the exercise of market power, rather than other underlying drivers of cost, including absolute scarcity for capacity during some hours. For instance, in an August 10 report provided to FERC in the context of the Commission's Investigation of Western Bulk Power Markets[2], the DMA was noted that:

> …there are many hours of extremely high prices when supply and demand are relatively tight, but there is no apparent shortage of supply. During these hours high prices are most likely the result of market power. The presence of market power can be verified by a high bid price over variable cost by many suppliers in the ISO's markets. The highest variable cost of in-state generators is below $100/MWh, while many suppliers routinely bid a significant part of their capacity at $750 (the price cap level). These bids had to be selected to meet the demand during high load periods.[3]

The August 10 report further explained that:

> The observed market power was the combined effect of the bidding activity of in-state and out-of-state generation resources. The available data and tools do not allow detailed analysis of the market power of out-of-state generation owners. The ISO, however, is not aware of any acute regional shortages in most of the high price hours. The high prices bid by out-of-state suppliers as well as the high prices quoted to ISO's out-of-market calls are indications of the market power of out-of-state suppliers. (p. 5)

Subsequently, in a report filed with FERC on October 20, 2000, DMA staff presented results of a more systematic, quantitative analyses of market power and any potential scarcity of supply within the CAISO system over the CAISO's first two and one half years. Results of this analysis showed significant degree of market power during the months of May to September 2000, and noted that:

> While a significant portion of the increase in wholesale costs above this competitive baseline have been incurred during hours of potential absolute resource scarcity, the bulk of these additional costs are attributable a lack of

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[2] As part of the Commission Investigation of Bulk Power markets, bid data for the ISO ancillary service and real time markets were provided to FERC.

[3] p.51

> competition, rather than scarcity. In addition, prices continued to significantly exceed competitive levels even after the ISO's real time price cap was lowered to $250 in August. (p.5)

A DMA report submitted with the ISO's comments on the Commission's November 1 order presented the results of quantitative analysis by DMA staff of the impact of market power and other factors on market costs. As explained in this report by the DMA:

> [S]ince late May of this year [2000], the combination of very tight supply and demand conditions — in conjunction with very limited ability of consumers to reduce consumption in response to high prices — has created the opportunity for the persistent exercise of market power in California's wholesale energy markets. The exercise of this market power has inflated wholesale energy costs significantly above levels that would have resulted under competitive market conditions, even after taking into account fundamental market factors driving up costs and hours of potential scarcity of supply. While some degree of market power may be tolerable from the perspective of defining a workably competitive market, the exercise of market power since late May of this year has clearly exceeded the level that may be considered consistent with a workably competitive market. Since additions of new supply are likely to merely keep pace with or even fall short of demand growth over the next two years, the exercise of significant market power can be expected to continue – if not worsen – over the next two years absent action to more effectively mitigate system-wide market power. [4]

The ISO's comments further emphasized that that "the ISO believes market outcomes in summer 2000 clearly demonstrate that market power was exercised, and that unrestricted market-based rate authority will continue to results in prices which are unjust and unreasonable." (p.15)

This report provides further analyses of the exercise and impact of market power in California's wholesale energy markets. The additional analysis addresses points or concerns that have raised before the Federal Energy Regulatory Commission (FERC) through written public comments, the FERC staff report and, most recently, the technical conference on market power mitigation held January 23, 2000.

- Section II presents additional analysis of the impact of market power on overall system prices is presented based on the price cost markup. In this analysis, the potential impacts of NOx emissions constraints is explicitly incorporated into the analysis.

- Section III examines wholesale prices in relation to the cost of investment in new

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[4] California Independent System Operator, Comments on FERC's November 1 Order on Proposed Remedies for California's Wholesale Markets*, Attachment A: Analysis of Market Power in California's Wholesale Energy Markets*, filed November 21, 2000.

supply. The results of this analysis indicate that there is ample room to reduce significantly wholesale prices observed over the last year, while still providing sufficient opportunity for recovery of costs in new investment.

2. Comparison of Market Costs with Competitive Baseline

Most economists agree that – at least in the short run --- the competitive price is short-run marginal costs, and that the competitive benchmark for assessing market power is the short-run marginal costs of the highest cost unit needed to met demand. The overall impact of the exercise of market power on California's energy markets has been assessed in several studies, by DMA and others, using variations of a similar *price cost marku*p methodology, which compares energy prices to the variable cost of the marginal unit needed to meet demand.[5] Result of these studies consistently show that wholesale prices in the PX Day Ahead and ISO real time have been significantly in excess of competitive levels over the last year, even after accounting for air emission costs[6] and scarcity.[7]

This section provides updated and expanded results of previous analyses by DMA. This analysis is based on the same basic approach described in previous reports to submitted to FERC.[8] Figure 2-1 illustrates and provides further description of the method used to estimate the marginal costs of the highest cost unit needed to meet demand in the ISO system during each hour. This price represents the market clearing price that would have prevailed under workably competitive conditions. Additional analysis and results presented in this report specifically address the degree to which the extremely high prices wholesale energy prices can be attributed to environmental emission costs and resource scarcity, rather than market power. In addition, several modifications have been added to account for the dramatic changes in market conditions, design and structure starting in December 2000. Refinements to this previous methodology are described in more detail in Appendix A.

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[5] Borenstein, Severin; Bushnell, James; and Wolak, Frank, "Diagnosing Market Power in California's Restructured Electricity Markets", August 2000; Updated results through June 2000 presented in *An Analysis of the June 200 Price Spikes in the California ISO's Energy and Ancillary Service Markets*, MSC Report, September 6, 2000).

A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000, P. Joskow and E. Kahn, November 21, 2000, submitted as attachment to Southern California Edison's Comments on FERC's November 1 Order on Proposed Remedies for California's Wholesale Markets, November 22, 2000.

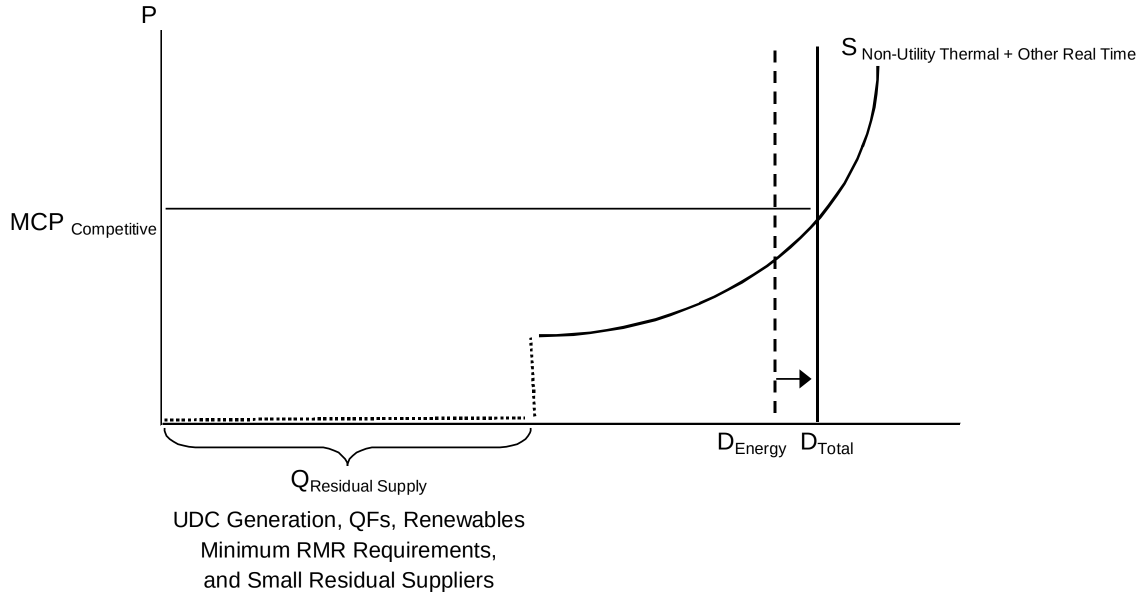
California Independent System Operator, Comments on FERC's November 1 Order on Proposed Remedies for California's Wholesale Markets*, Attachment A: Analysis of Market Power in California's Wholesale Energy Markets*, filed November 21, 2000.

[6] The issue of emissions has been previously addressed in analysis by Joskow and Kahn (2000) submitted as part of these proceedings.

[7] Issue of potential scarcity rents addressed in August 10 DMA Report and Appendix A (November 22).

[8] ISO Comments on November 1 Order, *Attachment A: Analysis of Market Power in California's Wholesale Energy Markets*, filed November 22, 2000. Additional background on the method used to assess resource scarcity was provided in the ISO's *Report on California Energy Market Issues and Performance: May-June*, 2000, Prepared by the Department of Market Analysis, August 10, 2000, submitted to FERC as part of its investigation of Western bulk power markets.

Figure 2-1. Price-Cost Markup Methodology



The competitive baseline price used in this analysis represents the estimated variable operating cost of the highest cost thermal generation unit needed to meet system demand each hour.

To estimate this competitive baseline price, the operating cost major non-utility owned thermal units within the CAISO system are first estimated based on unit heat rates, spot market gas prices, estimated O&M costs, including NOx emissions. The availability of these units each operating day is determined based on outage data reported to the ISO, and whether a unit is in operation and/or bid into the ISO markets. Through October 2000, the "supply curve" used in this analysis includes real time energy bids from imports submitted as Replacement Reserve and Supplemental Energy bids in this supply curve.

The net system demand that must be met by these resources is then calculated for each hour by first increasing total system loads to account for additional capacity needed for on-line reserves (about 7% for upward regulation and spinning reserve), as shown in the figure above. The portion of this demand met by utility owned generation, scheduled imports, renewables and smaller "fringe" suppliers is then "netted out" of demand. In practice, this supply can be effectively "netted out" of system demand by including it as "must-run" supply, as shown in the figure above.

As illustrated above, the competitive baseline price represents the variable operating cost of the highest cost thermal generation unit needed to meet system demand each hour. The *price-cost markup* is calculated based on the degree to which actual market costs exceed costs that would be incurred at this competitive baseline price. Total costs are based on net loads after accounting for generation owned or already under contract to UDCs. Additional details of this methodology are provided in Appendix A.

2.1 Updated Results Including Potential NOx Emissions and Scarcity

Results of this updated analysis (presented in Table 2-1 and Figure 2-2) show that even after accounting for potential emission costs and costs incurred during hours of potential resource scarcity, market prices have clearly exceed levels consistent with workably competitive wholesale markets.

- During calendar year 2000, results show that about 29% of overall wholesale energy costs are attributable to market power. Even if it is assumed that high prices during hours of potential resource scarcity do not reflect market power in any degree, the results indicate that about 29% of wholesale energy costs are attributable to market power.[9]

- Over the most recent 12 month period (while includes the first two months of 2001), results show that the gap between wholesale prices and competitive levels continues to grow. As shown on Table 2-1, the gap between 12-month wholesale prices and competitive levels increases from $33 to $50 when the first two months of 2001 are included in the analysis, with the price cost markup rising from about 29% to 31. At the same time, the analysis illustrates the stark shift in market conditions and behavior that occurred between May and June of 2000.

- A relatively small portion of the markup above competitive baseline costs identified in this analysis may be explained as "scarcity rents" incurred when overall demand exceeds supply. As shown in Table 2-1, less than one-tenth of the overall impact of market power in this analysis can be attributed to absolute resource scarcity. The relatively minor impact on results can be attributed to the fact that the model does explicitly factor in actual demand conditions and supply resources available each hour, so that the competitive baseline price reflects the higher cost of energy from specific resources needed when demand for capacity (including operating reserves) exceeds the available supply of capacity.

Section 2.3 of this report also shows that market power is exercised in all hours, not just Stage 3 emergencies.

2.2 Overall Impact of Market Power on Consumer Costs

Results of the analysis of market power based on the price-cost markup can also be applied to estimate the overall impact of market power on consumers. Table 2-2 summarizes these net total costs, after taking into account the amount of generation owned or under contract to utility distribution companies (UDCs). Table 2-2 also provides estimates of these costs excluding costs incurred during hours of potential resource scarcity. As shown in Table 2-2, the degree of market power observed in California wholesale market represents additional total costs of about $6.8 billion since May 2000. Only about $600 million of these additional costs were incurred during hours

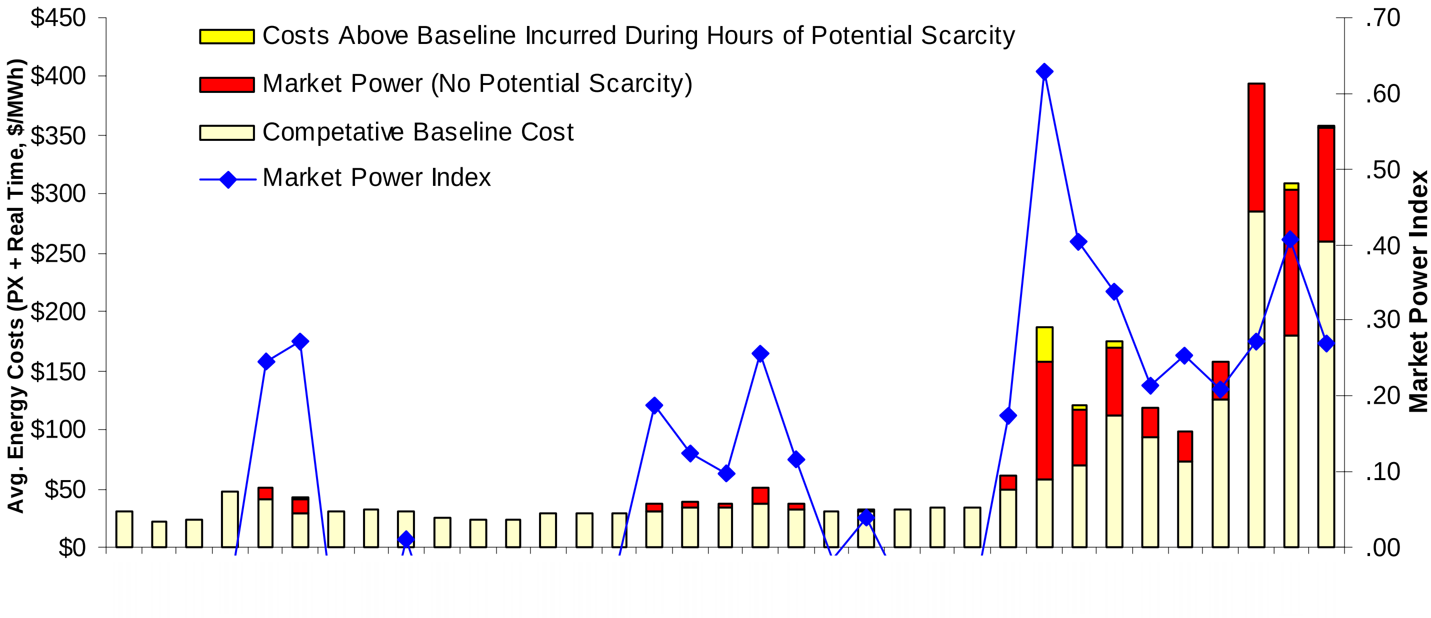
[9] For purposes of the analysis, hours of potential scarcity include all hours in which the total available market supply of capacity was less than total system energy demand plus 10% reserve for ancillary services (3% upward regulation, plus 7% operating reserve).

of potential resource scarcity, so that even excluding these hours, wholesale energy costs have been driven up over $6.2 billion since May 2000 by the exercise of market power.

Table 2-1. Analysis of Impact of Market Power on Wholesale Energy Prices

Period	Avg. Wholesale Cost ($/MW) [1] A	Competitive Baseline Costs ($/MW) B	Avg. Price-Cost Markup (A – B)	Markup during Hours of Potential Scarcity	Markup during Hours of No Potential Scarcity	Markup as Percent of Total Wholesale: All Hours	Markup as Percent of Total Wholesale: w/o Hours Potential Scarcity
April 1998	$23	$30	-$7	$0	-$7	-26%	-26%
May	$13	$19	-$6	$0	-$6	-42%	-42%
Jun	$14	$23	-$10	$0	-$10	-59%	-59%
Jul	$36	$31	$4	-$1	$5	-5%	-5%
Aug	$43	$32	$11	$2	$10	25%	25%
Sep	$38	$29	$9	$1	$8	27%	27%
Oct	$27	$31	-$4	$0	-$4	-12%	-12%
Nov	$26	$32	-$5	$0	-$5	-17%	-17%
Dec	$30	$30	$0	$0	$0	1%	1%
Jan 1999	$22	$26	-$3	$0	-$3	-13%	-13%
Feb	$20	$24	-$4	$0	-$4	-21%	-21%
Mar	$20	$24	-$4	$0	-$4	-18%	-18%
Apr	$25	$28	-$2	$0	-$2	-8%	-8%
May	$25	$28	-$2	$0	-$2	-6%	-7%
Jun	$27	$29	-$2	$0	-$3	-3%	-2%
Jul	$35	$30	$5	$1	$4	19%	19%
Aug	$38	$35	$3	$1	$3	11%	12%
Sep	$36	$34	$2	$1	$2	10%	10%
Oct	$50	$38	$12	$0	$12	26%	26%
Nov	$36	$33	$2	$0	$2	12%	12%
Dec	$30	$32	-$2	$0	-$2	-2%	-2%
Jan 2000	$32	$32	$0	$0	$0	4%	4%
Feb	$30	$33	-$3	$0	-$3	-6%	-6%
Mar	$30	$34	-$5	$0	-$5	-13%	-13%
Apr	$31	$35	-$4	$0	-$4	-8%	-8%
May	$58	$47	$11	$2	$9	23%	17%
Jun	$147	$57	$90	$32	$58	63%	57%
Jul	$112	$63	$49	$12	$37	41%	38%
Aug	$167	$82	$85	$24	$61	39%	32%
Sep	$118	$84	$34	$6	$29	24%	21%
Oct	$97	$72	$25	$1	$24	25%	25%
Nov	$156	$128	$27	$1	$26	21%	21%
Dec	$395	$292	$102	$1	$101	28%	28%
Jan 2001	$307	$205	$81	$5	$76	43%	41%
Feb	$361	$294	$64	-$3	$68	28%	27%
Jan ’00-Dec ‘00	$117	$84	$33			29%	27%
Mar ‘00-Feb ’00	$162	$112	$50			31%	30%

Figure 2-2. Analysis of Impact of Market Power on Wholesale Energy Prices (Based on Results Shown in Table 2-1)



Notes: Table 2-1 and Figure 2-2

[1] Until November 2000, Average Wholesale Cost = [Hour Ahead Schedule$_{NP15}$ x PX MCP$_{NP15}$] + [Hour Ahead Schedule$_{SP5}$ x PXMCP$_{SP15}$] + [(System Load Hour $_{NP15}$ - Ahead Schedule$_{NP15)}$ x Real Time MCP $_{NP15}$] + [(System Load Hour $_{SP15}$ - Ahead Schedule$_{SP15)}$ x Real Time MCP $_{SP15}$] ,where zonal schedules and loads are estimated based on Utility Distribution Company (UDC) area schedules and generation (with NP15 prices applied to PG&E area and SP15 prices applied to other SCE and SDG&E areas). Starting in December 2000, average wholesale cost based only on total average cost of real time energy (including out-of-market purchases).

[2] Hours of potential scarcity defined based on hours when total available market supply of capacity was less than total system energy demand plus 10% ancillary services (3% upward regulation, plus 7% operating reserve).

[3] Overall Price-Cost Markup = (Actual Wholesale Costs - Baseline Costs) / Baseline Costs, with <u>hourly costs weighted by total system loads minus generation owned or under contract to UDCs</u> (utility-owned generation, QFs, etc.)

Table 2-2. Impact of Market Power on Wholesale Energy Costs (Millions of Dollars)

Time Period	Net Wholesale Costs [1] (A)	Competitive Baseline Costs [2] (B)	Excess (A – B)	Excess During Hours of Scarcity	Excess During Hours of No Scarcity
May 2000	$626	$518	$108	$5	$103
June	$1,756	$651	$1,106	$311	$795
July	$1,348	$804	$544	$67	$477
Aug	$2,201	$1,459	$743	$110	$632
Sept	$1,395	$1,098	$298	$7	$291
Oct	$1,101	$823	$279	$0	$279
Nov	$1,658	$1,314	$344	$3	$341
Dec	$4,117	$2,995	$1,122	$9	$1,113
Jan 2001	$3,353	$1,989	$1,364	$71	$1,293
Feb	$3,609	$2,641	$968	$19	$949
Apr-Sept	$7,328	$4,529	$2,798	$501	$2,297
Oct-Nov	$2,760	$2,137	$623	$3	$620
Dec-Feb	$11,079	$7,625	$3,454	$99	$3,355
	$21,167	$14,292	$6,875	$603	$6,272

Table 2-2 Notes

[1] Net wholesale costs estimated based on volume of net ISO load not met by UDC generation and must-take contracts. Until November 2000, Total wholesale costs calculated on hourly basis by applying PX constrained price by net non-Hour Ahead Schedule, plus cost of unscheduled load met at ISO real time imbalance price. Starting in December 2000, average wholesale cost based only on total average cost of real time energy (including out-of-market purchases).

[2] Competitive baseline costs based on estimate of competitive hourly price multiplied by net load not met by UDC generation and must-take contracts.

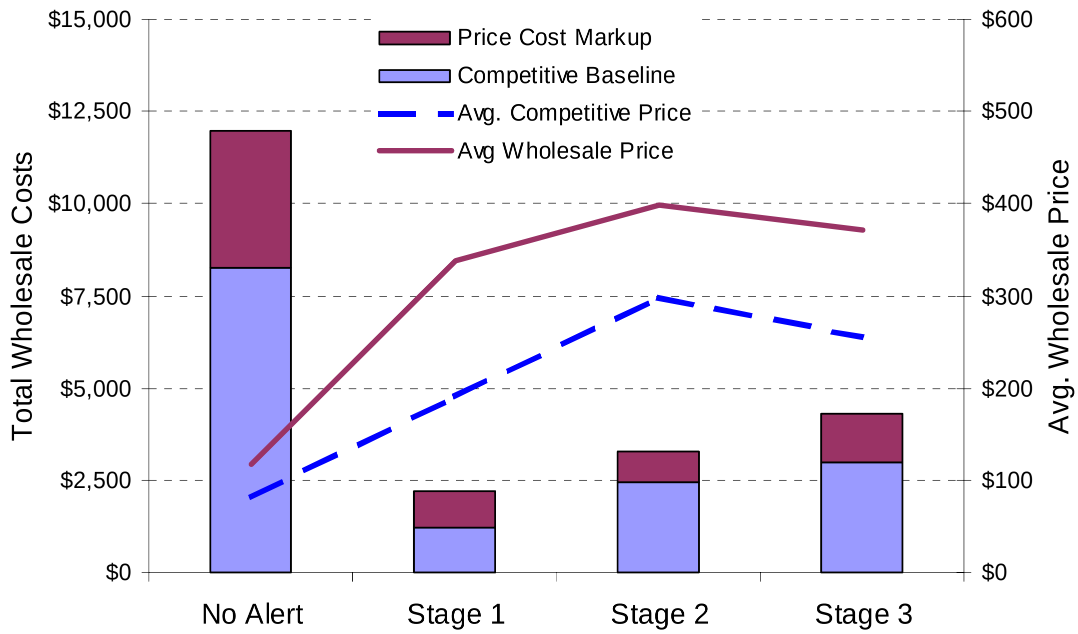
2.3 Impact of Market Power During Stage 3 Emergencies

The FERC staff report and several recent Commission Orders are abased on the premise that market power is primarily exercised during Stage 3 alerts, and that market power mitigation is therefore only necessary during such system emergencies. However, results of this analysis also show that market power is exercised under a wide range of system conditions, rather than just during Stage 3 emergencies. Table 2-3 and Figure 2-3 summarize results of the analysis presented in the previous sections in terms of the degree of market power observed during different system conditions over the last 12 months. Of the $6.8 billion in additional wholesale cost that may be attributable to market power, about 80% were incurred during non-Stage 3 hours. Over half of these additional costs were incurred when no system alert was in effect.

Table 2-3. Impact of Market Power on Wholesale Energy Costs By System Condition (March 2000 – February 2001)

	No Alert	System Alerts Stage 1	System Alerts Stage 2	System Alerts Stage 3	All Hours
Hours	7,165	345	469	782	8,761
Net GWh [1]	101,937	6,448	8,134	11,600	128,118
Avg Wholesale Price ($/MW)	$117	$339	$400	$372	$170
Avg. Competitive Price	$81	$192	$298	$256	$116
Avg. Markup	$36	$147	$101	$116	$53
Total Wholesale Cost (Millions)	$11,976	$2,185	$3,249	$4,310	$21,720
Total Competitive Cost	$8,269	$1,240	$2,426	$2,967	$14,903
Total Markup	$3,707	$945	$823	$1,343	$6,818

Figure 2-3. Impact of Market Power on Wholesale Energy Costs
By System Condition (March 2000 – February 2001)



3. Wholesale Energy Prices Compared to Cost of New Supply

The generally accepted competitive benchmark for assessing market power is the short-run marginal costs of the highest cost unit needed to met demand. However, short-term marginal cost pricing provides no assurance that such contributions to fixed costs will be sufficient to cover the fixed costs associated with investment in new supply. For this reason, concerns have been expressed that applying this benchmark to constrain the exercise of market power will discourage entry of new generating projects needed to meet growing demand and replace existing capacity that are not longer economical to operate because prices will not support the cost of investment in new supply.

A noted in a recent report by the California Energy Commission:

> The long-term price of electricity in an market-driven system should settle at a level just sufficient to pay for additional generation capacity, as it is needed. If the market is structured and working properly, electricity prices higher than a generator's revenue requirement indicate new generation capacity is needed. Prices lower than the level needed to attract new investment should indicate a surplus of generation capacity exists.[10]

In the context of the wholesale electricity markets, it has been argued that "monopoly rents are the excess of prices over the *long-run* marginal cost of generation," and that "market invention should not even be considered unless market power is being exercised to the degree that 'monopoly rents' are generated."[11] As suggested by a Justice Department official participating in the January 23 Technical Conference held in conjunction with these proceedings:

> Monopoly power is often said to be a substantial amount of market power, but there is a more precise definition that can be stated in terms of the appropriate competitive benchmark price…In the short, the competitive price is short-run marginal cost, and that is the competitive benchmark for defining "market power." The competitive price over the long run is long-run marginal costs, and that is the competitive benchmark for defining "monopoly power…"Monopoly rents' are returns in excess of those necessary to attract capital that are reaped through the exercise of market power. [12]

In order to address the degree of market power in California's wholesale energy

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[10] *Market Clearing Prices under Alternative Resource Scenarios: 2000-2010*, Staff Report by the California Energy Commission (February 2000), Section III: New Market Entry, p.1

[11] Comments of Gregory J. Werden, Before the Federal Regulatory Energy Commission, Docket No. PL98-5-000. p.6

[12] Remarks of Gregory J. Werden, Before the Federal Regulatory Energy Commission at Technical Conference on Development of Market Monitoring Procedures, January 23, 2001,

markets from this perspective, this section examines the economics of investment in new supply capacity given observed prices in California's wholesale energy markets over the last three years.

The analysis is based on a typical 500 MW combined cycle unit, since the majority of projects proposed in California and the WSCC during the last three years have been 500 MW gas-fired combined cycle plants.[13] Table 3-1 summarizes key assumptions used in this analysis. Appendix B of this report describes the operational and scheduling modeling algorithm, and cost inputs used in the analysis.

Table 3-1. Study Assumptions:
Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Outage Rate (Scheduled & Forced)	8%
Heat Rates (MBTU/MW)	
Maximum Capacity	7,200
Minimum Operating Level	8,200
Installed Capacity Costs	$500 - $600 /kW
Fixed Annual O&M	$10 /kW
NOx Emissions	.1 lbs/MWh
Other Variable O&M	$2/MWh
Fixed Charge Rate [1]	14 –15 %
Fixed Cost Revenue Requirement [2]	$70 - $90/kW/year

[1] Range of 14%-15% based on 14.5% fixed revenue requirement and sensitivity analysis of specific financial assumptions outlined in *Market Clearing Prices under Alternative Resource Scenarios: 2000-2010*, Staff Report by the California Energy Commission (February 2000), Section III: New Market Entry, p.2-4.

[2] [$500/MW installed costs x 14% Fixed Charge Rate] + $10/kW Fixed O&M = $70/kW/year.
[$600/MW installed costs x 15% Fixed Charge Rate] + $10/kW Fixed O&M = $90/kW/year.

13 *Market Clearing Prices under Alternative Resource Scenarios: 2000-2010*, Staff Report by the California Energy Commission (February 2000), Section III: New Market Entry, p.1

Results of this analysis are displayed in Figures 3-1 and 3-2, which show the total 12-month contribution to fixed costs that would be earned by a new combined cycle unit given wholesale energy prices in Northern and Southern California for each rolling 12 month period from May 1998 through January 2001.[14] Figures 3-1 and 3-2 also show results relative to cost range of such new supply, which is estimated to range between $70 and $90/kW/year.

Results of this analysis show that over the first year of operation, wholesale energy prices in California were not sufficient to stimulate investment in new supply. During 1999, however, prices in the ISO's northern zone (NP15) rose to levels that provide contributions to fixed costs in the range required to cover the costs of new supply, while prices in the southern zone (SP15) still did not appear to support investment in new baseload supply. These findings are consistent with previous analysis performed in the first quarter of 2000 by DMA[15] and the California Energy Commission (CEC).[16]

Figure 3-3 compares the contribution to fixed costs a new combined cycle unit would have earned in the 12-month period from January to December 2000 at actual wholesale energy prices to the cost of new supply. In addition, Figure 3-3 includes the contribution to fixed costs a new combined cycle unit would have earned in this same 12-month period given the hourly competitive baseline prices developed based on the analysis presented in Section 2 of this report.

Results of this analysis show that the extremely high prices observed since the summer of 2000 in California provide contributions to fixed costs that significantly exceeded the level needed to support investment in new supply. On an annualized basis, wholesale energy prices since in January 2000 have exceeded the annualized cost of new supply investment by about 400%, and would allow recovery of an investment in new supply in a period of just over one year. A new combined cycle plant earning the hourly competitive baseline price developed based on the analysis presented in Section 2 of this report would have earned from about 200% to almost 300% of the annualized cost of new supply investment.

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[14] More detailed numerical results are provided in Appendix B.

[15] *Price Cap Policy for Summer 2000*, Prepared by the Department of Market Analysis, March 2000, pp.16-18.

[16] *Market Clearing Prices under Alternative Resource Scenarios: 2000-2010*, Staff Report by the California Energy Commission (February 2000), Section III: New Market Entry. This report provides a more detailed discussion of range of factors affecting the cost-effectiveness of new supply and, including numerous difficult-to-quantify factors affecting new supply in California.

Figure 3-1. Financial Analysis of New Combined Cycle Unit – NP15

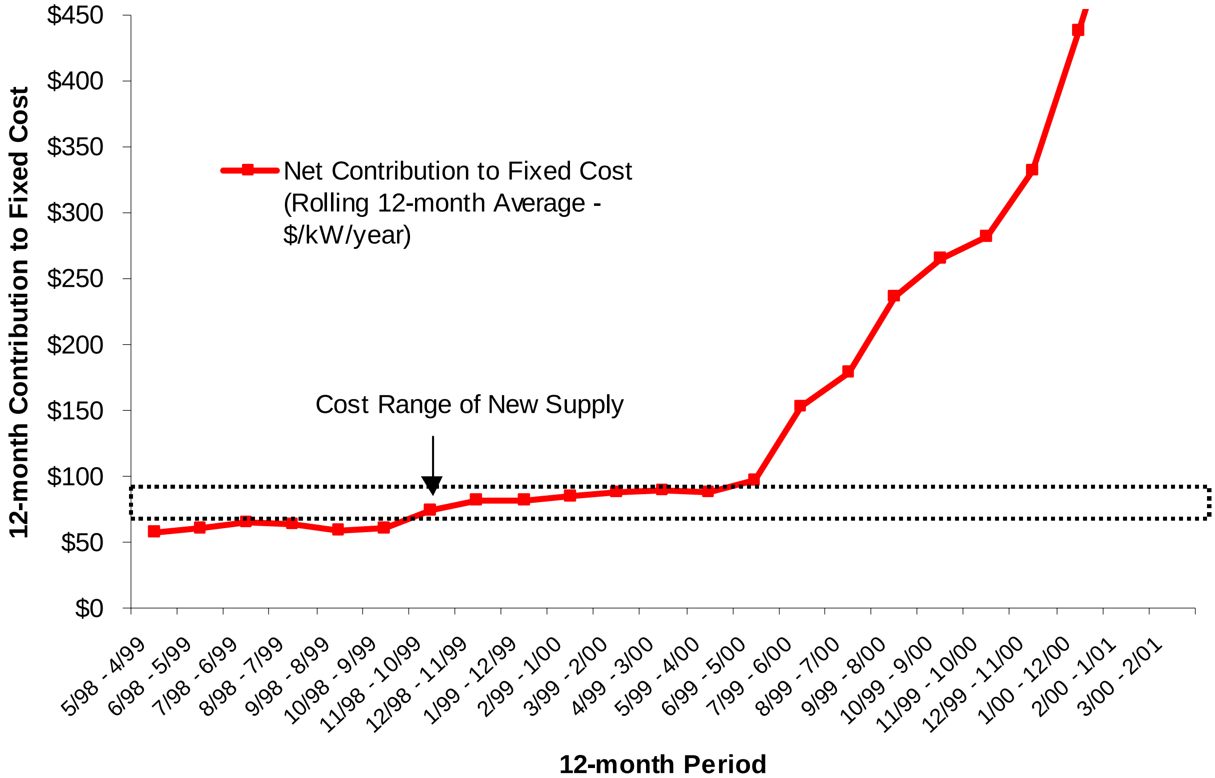


Figure 3-2. Financial Analysis of New Combined Cycle Unit – SP15

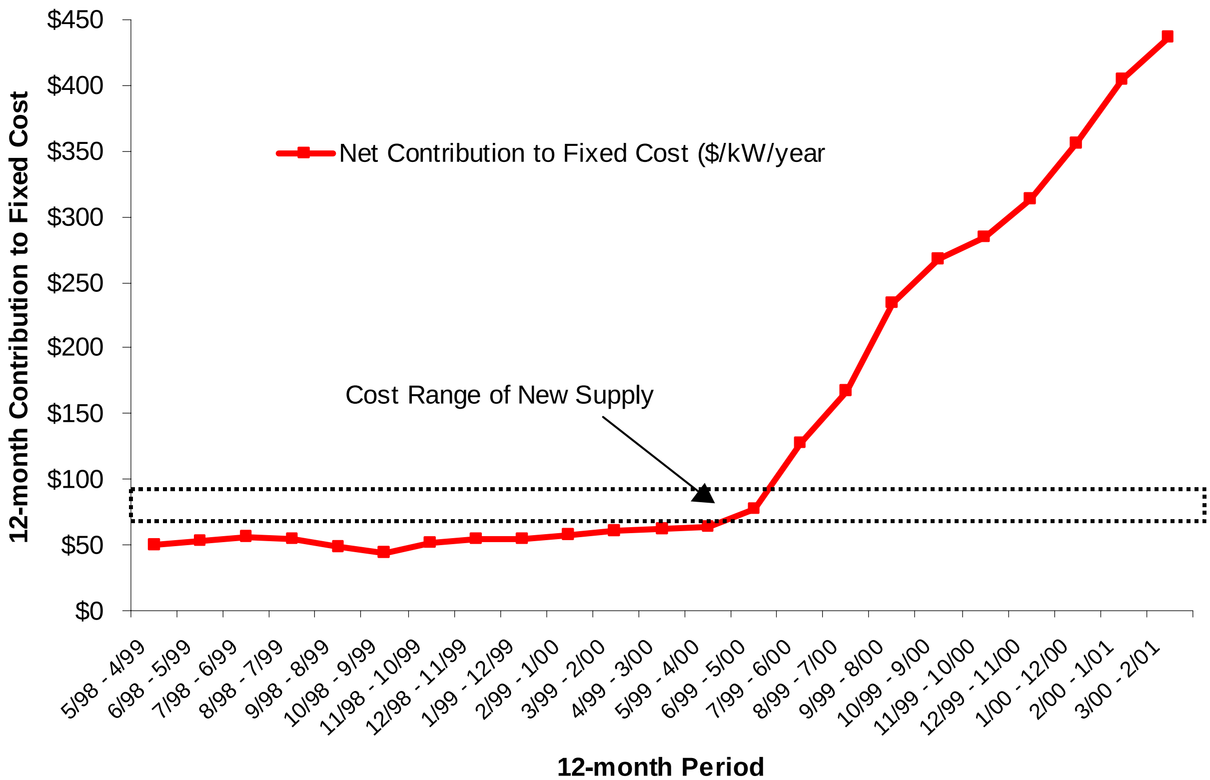
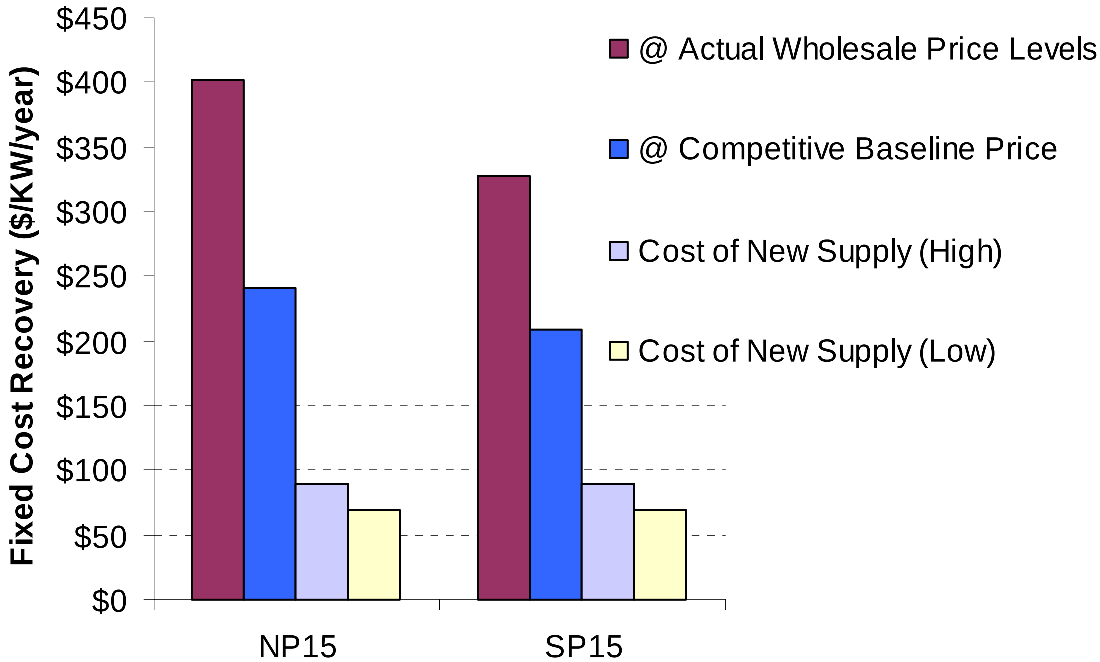


Figure 3-3. Contribution to Fixed Costs vs. Cost of New Supply



	Average Revenue	Average Cost	Load Factor	Contribution to Fixed Cost ($/kW/yr)
Northern California (NP15)				
Actual Prices	$105	$47	85%	$403
Competitive Baseline	$ 82	$50	91%	$263
Southern California (SP15)				
Actual Prices	$100	$48	79%	$328
Competitive Baseline	$ 82	$54	90%	$227

Appendix A: Extensions and Modifications in Analysis of Actual Wholesale Costs Compared to Competitive Baseline Costs

Analysis presented in Section II of this report provides updated and expanded results of previous analyses by the ISO's Department of Market Analysis (DMA). This analysis is based on the same basic approach described in previous reports submitted to FERC[17]. Figure 2-1 of this report also illustrates and provides further description of this approach. The following section of this Appendix describes key refinements made in the basic methodology used in previous analyses. The final section of this Appendix provides a more detailed summary of the basic methodology.

Modifications and Refinements in Methodology

Refinements to the methodology used in previous analyses are described below:

- **NOx Emissions.** The analysis directly includes NOx emissions costs in the variable cost of each unit within the South Coast Air Quality Management District (SCAQMD). NOx emission rates were estimated based on data contained in previously filed Reliability Must Run (RMR) contracts and EPA date on average emissions rates during 1999. Rates for combustion turbines for which RMR or EPA data were not available were based on an engineering estimate of 7 lbs/MWh.
- **Real Time Energy Costs.** Starting in late November 2000, *out-of-market* (OOM) costs incurred by the ISO began to represent a major portion of total real time energy costs. In addition, for the first time the average cost of OOM purchases began to exceed the ISO's real time price by a significant degree. After December 8, purchases above the "soft cap" on the real time market clearing price (MCP) that are paid on an "as-bid" basis also accounted for a major share of real time costs. Consequently, the hourly real time price used in this analysis to calculate total wholesale costs now represents the weighted average of all real time energy purchased by the ISO from these three different segments of the real time market: (1) imbalance energy bid at or below the soft cap receiving the MCP, (2) bids over the "soft cap" accepted that are paid "as-bid", and (3) OOM purchases.

- **Net Wholesale Energy Costs.** Starting in December, 2000, there was also a rapid drop in generation scheduled in the PX Day Ahead market that started as gas prices spiked in the first week of December, and concluded with the closing of the PX market at the end of January 2001. In addition, during periods of December and January, PX constrained prices were well below the cost of real time energy. However, during these periods, virtually all of the generation clearing in the PX at these prices was utility-owned generation. Therefore, beginning in December 2000, total net wholesale costs are estimated based only on the cost of energy met

[17] The approach used to estimated the competitive baseline price is described in Attachment A of the ISO's Comments on the Commission November 1 Order (November 22, 2000). Additional background on the method used to assess resource scarcity was provided in the ISO's *Report on California Energy Market Issues and Performance: May-June*, 2000, Prepared by the Department of Market Analysis, August 10, 2000, submitted to FERC as part of its investigation of Western bulk power markets.

through the real time market (including OOM purchases), as described above. This modification more accurately reflects the wholesale cost of net load not met by UDC generation or existing contracts.

- **Outages.** As with previous analysis, the availability of each non-utility thermal unit is determined for each operating day. However, for periods since May 2000, the daily availability of each unit is based on data on scheduled and forced outages reported by the ISO's Outage Maintenance and Operations staff which have been complied by DMA for use in this analysis. For periods prior to May 2000, comprehensive data on unit outages is not available from these same sources. Therefore, the availability of units prior to this period is estimated as in previous analysis based on metering, scheduling and bid data. Specifically, if metering information, final energy and ancillary schedules, and supplemental energy bids indicated a unit was available during any hour of a day, it was assumed the unit's full capacity was available for that operating day.

- **Real Time Supply of Imports.** Previous analyses included real time energy bids (from Replacement Reserve and Supplemental Energy) in the supply curve (e.g. see Figure 2-1 of this report). This approach is not used for the period starting in November 2000 for several reasons. First, the bulk of imports after this period were scheduled through out-of-market (OOM) transactions at specified prices, rather than being bid into the real time market. Thus, it can no longer be assumed that prices of these import transactions reflect actual costs. Second, given the chronically uncompetitive conditions that have prevailed since late November in the ISO's real time market, it is not longer appropriate to assume that supplies of imports are being offered into the market or purchased out-of-market at prices that reflect costs. Thus, starting in November 2000, it is assumed that the cost of all imports purchased out-of-market is equal to the minimum of their reported transaction price, or a benchmark cost of a relatively inefficient thermal unit (calculated by multiplying the daily spot market gas price by a 12,000 heat rate).

Description of Methodology

The DMA has also performed systematic quantitative analyses of market power and any potential scarcity of supply within the CAISO system by comparing the difference between the actual wholesale price of energy in the CAISO system and an estimate of baseline costs that would be incurred under competitive market conditions.

The competitive baseline price used in this analysis represents the estimated variable operating cost of the marginal thermal generation unit within the CAISO system needed to meet system demand each hour, after taking into account the actual supply of imports and other supply resources within the CAISO control area. The degree to which actual wholesale energy price (including load met in the PX Day Ahead market and the ISO real time market) exceeds this competitive baseline cost (expressed as a percentage of actual wholesale prices) represents the *price-cost markup.*

The methodology used to determine this competitive market baseline and the price-cost mark-up is as follows.

1. First, the operating cost of major non-utility owned thermal units within the CAISO system are estimated based on unit heat rates, spot market gas prices, estimated O&M costs of $4/MWh for combustion turbines and $2/MWh for other thermal units. As noted above, analysis presented in this report includes potential NOx emission costs.

2. Second, the availability of these units is determined for each operating day. For periods since May 2000, the daily availability of each unit is based on databases on scheduled and forced outages complied by the ISO's Outage Maintenance and Operations staff. For periods prior to May 2000, comprehensive data on unit outages is not available from these same sources. Therefore, the availability of units prior to this period is estimated based on metering, scheduling and bid data. The availability of individual units each operating day was based on whether or not a unit was actually in operation and/or bid into the ISO markets. Specifically, if metering information, final energy and ancillary schedules, and supplemental energy bids indicated a unit was available during any hour of a day, it was assumed the unit's full capacity was available for that operating day. As noted above, previous analyses by DMA have relied on this later approach, since comprehensive data on unit availability was not available in electronic format from outage scheduling and operations records.

3. Third, a thermal supply curve is developed by ranking units based on price, and summing up the capacity available at each price level. In the base case of our analysis, we also include real time energy bids from imports submitted as Replacement Reserve and Supplemental Energy bids in this supply curve (rather than simply "netting out" these imports from ISO system demand). As noted above, this approach is not used for the period starting in November 2000, due to the fact that the bulk of imports after this period were scheduled through out-of-market (OOM) transactions at specified purchase prices (rather than single price auction bid prices), and chronically uncompetitive conditions that have prevailed since late November in the ISO's real time market. Thus, starting in November 2000, it is assumed that the cost of all imports purchased out-of-market is equal to the minimum of their reported transaction price, or a benchmark cost of a relatively inefficient thermal unit (calculated by multiplying the daily spot market gas price by a 12,000 heat rate).

4. Fourth, the net demand that must be met by these sources of supply is calculated for each hour *t* as follows:

$$\text{Net Demand}_t = \text{System Energy Demand}_t - \text{Imports}_t - \text{Residual ISO Supply}_t$$
$$- \text{Estimated System Losses and Unaccounted for Energy}_t$$

Where:

$$\text{System Energy Demand}_t = \text{Actual ISO System Load}_t$$

+ Upward Regulation Requirements$_t$
+ Spinning Reserve (estimated at 3% of system load)

Imports$_t$ = $\sum_i$ Final Hour Ahead Energy Schedule$_{i,t}$ + Real Time Energy Dispatched$_{i,t}$

Residual ISO Supply$_t$ = $\sum_j$ Max [Metered Output$_{j,t}$, Final Hour Ahead Energy Schedule$_{j,t}$ + Upward Regulation Capacity Scheduled$_{j,t}$ + Real Time Energy Dispatched$_{i,t}$ + RMR Schedule Change$_{j,t}$]

i = All import schedules into the ISO control area

j = All generating resources within the ISO control area other than major non-utility thermal units

System Losses and Unaccounted for Energy in each hour *t* were estimated based on the difference between hourly system loads reported by the ISO based on telemeter data and the summation of estimated generation from all sources within ISO control area plus final import schedules.[18]

5. Fifth, a competitive baseline price is calculated based on the supply curve of non-utility thermal units and real time energy imports (Step 3) and the net demand needing to be met from these sources of supply (Step 4).

6. Sixth, the *price-cost markup* is calculated based on the degree to which actual market costs (net of generation owned or already under contract to UDCs) exceed costs that would be incurred at this competitive baseline price. Specifically, the price cost markup is calculated for each month (or other time period) by aggregating results for each hour t as follows:

$$\text{Markup} = \frac{\sum \text{Net Market Costs}_t - \text{Competitive Baseline Costs}_t}{\sum \text{Net Market Costs}_t}$$

Where:

Net Market Costs$_t$ = (Total ISO Load$_t$ - UDC Generation$_t$) $\times$ Average System Energy Price$_t$

[18] For virtually all peak hours with relatively tight supply and demand conditions, the difference between the system load and the sum of unit level estimates of generation (plus import schedules) was between approximately 1 to 3% of the ISO official estimate of system loads. This is within the range expected to line losses. Most importantly, however, this reconciling reported system loads with “bottom up” calculations based on scheduled and metered generation of individual resources and imports schedules ensures that any missing or inaccurate data does not introduce significant errors into the analysis.

$$\text{Average System Energy Price}_t = (\text{Scheduled Load}_t \times \text{PX MCP}_t) + (\text{Unscheduled Load}_t \times \text{Real Time MCP}_t)$$ [19]

$$\text{Competitive Baseline Costs}_t = (\text{Total ISO Load}_t - \text{UDC Generation}_t) \times \text{Competitive Baseline Price}_t$$

As noted in the previous section, beginning in December 2000, total net wholesale costs are estimated based only on the cost of energy met through the real time market (including OOM purchases). This modification was made to more accurately reflect the wholesale cost of net load not met by UDC generation or existing contracts, given the rapidly declining volume of non-utility generation scheduled in the PX and the ultimate cessation of the PX market at the end of January 2001.

7. In order to assess the degree to which high wholesale prices may be attributable to absolute scarcity of supply, rather than market power, we also identify the portion of the price-cost markup occurring during hours of potential resource scarcity. In this analysis, scarcity is defined based on hours when total available supply in the ISO system (including import bids and out-of-market purchases) is less than total system demand for energy plus 10% ancillary services (representing about 3% upward regulation, and 7% operating reserve). Additional details of the methodology and results of our analysis of scarcity were presented in a previous DMA report (*Report on California Energy Market Issues and Performance: May-June, 200*0, Special Report by ISO DMA, August 10, 2000).

[19] Estimated PG&E area loads (net of utility generation) multiplied by prices in NP15 and net SCE/SDG&E area loads multiplied by SP15 prices.

Appendix B: Analysis of Investment in New Supply

In order to address the degree of market power in California's wholesale energy markets from this perspective, this section examines the economics of investment in new supply capacity given observed prices in California's wholesale energy markets over the last three years. The analysis is based on a typical 500 MW combined cycle unit. Table 3-1 summarizes key plant characteristics and financial assumptions used in the analysis. The operational and scheduling assumptions used for each unit are summarized below:

- An initial 24-hour operating scheduled is first determined based on PX Day Ahead prices. The unit is scheduled at full load when hourly prices exceed variable operating costs, and is scheduled at minimum operating level when prices fall below it variable operating costs.

- The initial schedule is then modified by applying an algorithm determine if it would be more economical to shut down the unit during hours when Day Ahead prices fall below the variable operating costs. The algorithm compares operating losses during these hours the cost of shutting down and restarting the unit: if operating losses exceed these shutdown/startup costs, the unit is scheduled to go off-line over this period.

- The adjusted schedule is further modified to account for the ability to dispatch any unloaded capacity in the real time market when imbalance prices exceed the unit's variable operating cost.

- Finally, a series of simplified ramping constraints are applied to the units schedule to approximate the degree to which the unit would need to deviate from this schedule given the unit's ramp rate. The unit's initial schedule determined based on the PX Day Ahead price is assumed to earn the PX price, and any deviations from the schedule (in response to the real time price, and during ramping up and ramping down periods) are assumed to earn the real time price.

Prices used in the analysis included the following:

- Daily spot market gas prices for southern and northern California. It should be noted that use of spot market gas prices may underestimate net revenues during 2000-2001, since a new combined cycle plant would be expected forward purchase a significant quantity of gas.

- Constrained Day Ahead PX and real time prices (NP15 and SP15).

- For the months of December 2000-February 2001, daily regional spot market prices (Peak and off-peak hours) were used, due to the dramatic decline in non-utility sales in the PX Day Ahead market starting in December 2000. Prices reported for the Palo Verde trading hub were used for southern California (SP15), with prices reported for the California Oregon Border (COB) were used for northern California (NP15).

A combined forced and planned outage rate of 8% is represented by decreasing total annual net operating revenues by this amount.

Table B-1. Financial Analysis of New Combined Cycle Unit – NP15

12-month Period Start	End	Average Revenue	Average Cost	Load Factor	Contribution to Fixed Cost ($/kW/yr)
May-98	Apr-99	$29.96	$20.28	69%	$53
Jun-98	May-98	$30.09	$20.35	73%	$56
Jul-98	Jun-98	$30.44	$20.46	75%	$59
Aug-98	Jul-98	$30.31	$20.48	75%	$58
Sep-98	Aug-99	$30.11	$20.72	73%	$54
Oct-98	Sep-99	$30.68	$21.08	73%	$56
Nov-98	Oct-99	$33.56	$21.68	73%	$69
Dec-98	Nov-99	$34.62	$21.74	73%	$75
Jan-99	Dec-99	$34.46	$21.70	74%	$75
Feb-99	Jan-00	$34.89	$21.91	76%	$79
Mar-99	Feb-00	$35.22	$22.27	78%	$81
Apr-99	Mar-00	$35.83	$22.86	79%	$82
May-99	Apr-00	$36.27	$23.31	78%	$81
Jun-99	May-00	$38.31	$24.19	79%	$90
Jul-99	Jun-00	$46.80	$25.60	82%	$141
Aug-99	Jul-00	$51.19	$27.02	84%	$164
Sep-99	Aug-00	$60.25	$28.78	86%	$218
Oct-99	Sep-00	$66.35	$31.16	86%	$244
Nov-99	Oct-00	$70.50	$33.08	86%	$260
Dec-99	Nov-00	$81.86	$38.09	86%	$305
Jan-00	Dec-00	$105.16	$46.80	85%	$403
Feb-00	Jan-01	$125.54	$52.35	85%	$505
Mar-00	Feb-01	$146.07	$57.55	86%	$610

Table B-2. Financial Analysis of New Combined Cycle Unit – SP15

12-month Period Start	End	Average Revenue	Average Cost	Load Factor	Contribution to Fixed Cost ($/kW/yr)
May-98	Apr-99	$31.01	$21.06	59%	$47
Jun-98	May-98	$30.92	$21.10	63%	$49
Jul-98	Jun-98	$31.21	$21.17	66%	$52
Aug-98	Jul-98	$30.90	$21.13	65%	$50
Sep-98	Aug-99	$30.32	$21.41	64%	$44
Oct-98	Sep-99	$30.22	$21.74	62%	$41
Nov-98	Oct-99	$31.81	$22.29	64%	$48
Dec-98	Nov-99	$32.32	$22.39	65%	$50
Jan-99	Dec-99	$32.28	$22.57	66%	$51
Feb-99	Jan-00	$32.71	$22.85	69%	$53
Mar-99	Feb-00	$33.17	$23.25	71%	$56
Apr-99	Mar-00	$33.99	$23.92	71%	$57
May-99	Apr-00	$34.92	$24.44	71%	$58
Jun-99	May-00	$37.87	$25.40	72%	$71
Jul-99	Jun-00	$46.66	$26.79	74%	$117
Aug-99	Jul-00	$53.60	$28.38	76%	$153
Sep-99	Aug-00	$64.95	$30.40	78%	$216
Oct-99	Sep-00	$71.33	$32.79	80%	$247
Nov-99	Oct-00	$75.56	$34.80	80%	$261
Dec-99	Nov-00	$84.10	$39.41	80%	$289
Jan-00	Dec-00	$100.11	$48.20	79%	$328
Feb-00	Jan-01	$114.29	$54.54	77%	$372
Mar-00	Feb-01	$128.07	$62.39	76%	$402