Impacts of Market Power In California's Wholesale Energy Market:

More Detailed Analysis Based on Individual Seller Schedules and Transactions in the ISO and PX Markets

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Executive Summary

This report provides the results of additional analyses undertaken by the California Independent System Operator Corporation's ("ISO's") Department of Market Analysis ("DMA") of the degree to which wholesale prices in California wholesale energy markets have exceeded competitive price levels over the period May 2000 through February 2001. The study builds upon estimates of the hourly competitive baseline price for the ISO system developed as part of a previous analysis submitted to the Commission. [1] When results of this hourly analysis were extrapolated to California's entire wholesale energy market (excluding generation still owned or under contract to the state's major Utility Distribution Companies), results showed potential prices in excess of competitive levels of over $6 billion for the period May 2000 through February 2001.

The analysis presented in this report specifically identifies the amount of these potential excess revenues that may have been realized each month in the PX and ISO markets, including the monthly amounts attributable to each individual seller and the amount of FERC jurisdictional and non-jurisdictional transactions in each of these markets. This analysis was performed in response to a letter order of March 30, 2001from the Federal Energy Regulatory Commission (FERC) staff requesting responses to various questions relating to two reports that accompanied the comments filed by the ISO on March 22, 2001 on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market.

In response to this request from Commission staff, DMA has conducted a "bottom up" accounting and analysis of hourly market activity by sellers and has determined the degree to which revenues for each transaction in the ISO markets and estimated revenues from energy scheduled with the ISO exceeded the system-level competitive baseline price developed as part of the previous analyses submitted to the Commission. Results of this analysis are summarized in Tables 1 through 4. These results are documented and presented in more detail in this report and a series of attachments. Electronic data files containing all the confidential hourly schedule and transaction level records for each specific market participant used in this calculation are being submitted to Commission staff.

As shown in these summary tables:

- Results of this analysis indicate total potential revenues in excess of competitive levels for the total wholesale market in excess of $6 billion. As shown in Table 4, total potential revenues in excess of competitive levels exceed $6.7 billion. Previous estimates did not include Ancillary Service markets, which account for about $430 million of total potential excess revenues identified in this study (see Table 3).

[1] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market*, March 2001, Prepared by Eric Hildebrandt, Department of Market Analysis. Submitted as Attachment B to the ISO's *Comments on FERC Staff's Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market*, March 22, 2001.

- Approximately $4 billion of the $6.7 billion of potential excess revenues identified in this study can be tied directly to specific schedules and transactions in the PX and ISO markets (Table 4).

- Approximately $2.4 billion of these revenues involve sales in the ISO's markets, with about $1.9 billion occurring in the real time energy market (Table 2) and about $460 million in the Ancillary Service market (Table 3).

- Energy scheduled in the PX energy market accounts for the remaining $1.5 billion of estimated revenues in excess of competitive levels. Sales in the PX market by individual market participants were identified based on transfers of scheduled energy to the PX by market participants acting as their own Scheduling Coordinator (inter-SC trades), combined with imports scheduled by participants from outside the control area through the PX as the Scheduling Coordinator. Additional analysis and verification based on actual PX data that were not available for use in this analysis given the timeframe of this report may be performed to verify and refine these estimates.

- Of these transactions in the PX and ISO markets, results show that approximately $3 billion in revenues in excess of competitive levels involve sales by entities directly under FERC jurisdiction and holding market-based rate authority (see Table 4). About $1 billion involves transactions by public entities and other participants whose sales are not under FERC jurisdiction.

- The remaining $2.7 billion represents potential bilateral market activity and self-supply by non-UDCs, represented by final Hour Ahead Energy schedules submitted by different Scheduling Coordinators.

Due to the limited timeframe and complexities of this analysis, additional analyses based on additional data would be warranted prior to use of these results in considering any action on refunds. However, electronic data files containing all the confidential hourly schedule and transaction level records for each specific market participant used in this calculation are being submitted to Commission staff to provide the starting point for such analysis. As noted above, additional analysis and verification of sales in the PX market based on PX data that were not available for use in this analysis represents one step toward verifying and refining results of this report.

Section I of this report provides a more detailed description of the methodology and algorithms used in this analysis in conjunction with the individual schedule and transaction records being provided to Commission staff in conjunction with this report.

Section II provides additional aggregate summary results.

Confidential Attachment A provides summary results for individual suppliers requested by FERC staff.

Summary of Total Estimated Revenues Above Competitive Market Baseline (Millions of Dollars)

Includes All Non-UDC Market Participants

Table 1. PX and other Wholesale Energy Markets

	All Non-UDC Hour Ahead Energy Schedules*	Estimated PX Sales Only	FERC Jurisdictional Sellers in PX	non-FERC Jurisdictional Sellers in PX
May-Sept	$1,781	$946	$856	$90
Oct-Feb	$2,557	$644	$575	$68
Total	$4,337	$1,590	$1,431	$158

Table 2. ISO Real Time Energy Market

	Real Time Energy Sales (non-UDC)	FERC Jurisdictional Sellers	non-FERC Jurisdictional Sellers
May-Sept	$698	$554	$145
Oct-Feb	$1,231	$732	$499
Total	$1,929	$1,286	$643

Table 3. ISO Ancillary Service Capacity Markets

	Ancillary Service Capacity Sales (non-UDC)	FERC Jurisdictional Sellers	Non-FERC Jurisdictional Sellers
May-Sept	$416	$349	$68
Oct-Feb	$23	$21	$2
Total	$439	$370	$69

Table 4. Total Energy and Ancillary Services

	Total Wholesale Energy + A/S (non-UDC)*	Total PX & ISO Markets (non-UDC)	FERC Jurisdictional Sellers in PX/ISO Markets	Non-FERC Jurisdictional Sellers in PX/ISO Markets
May-Sept	$2,896	$2,061	$1,758	$303
Oct-Feb	$3,810	$1,898	$1,329	$569
Total	$6,706	$3,958	$3,087	$871

* Total non-UDC wholesale market estimated based on total Hour Ahead Schedules for all non-UDC resources/imports/exports scheduled in the ISO system, with assumed sale price equal to PX Day Ahead MCP (through November 2000) and average ISO real time price (starting in December 2000).

I. Methodology

1.1 Overview

This study builds upon estimates of the hourly competitive baseline price for the ISO system given hourly load and supply conditions, spot market gas prices, and other factors that could be expected to affect system marginal costs under competitive market conditions developed as part of a previous analysis submitted to the Commission.[2] As part of this previous analysis, the total potential impacts of market power on prices in California's wholesale markets were estimated by extrapolating results of this analysis to the entire ISO system based on hourly system schedules, loads and prices. Results showed potential revenues in excess of competitive levels of over $6 billion for the period May 2000 through February 2001.

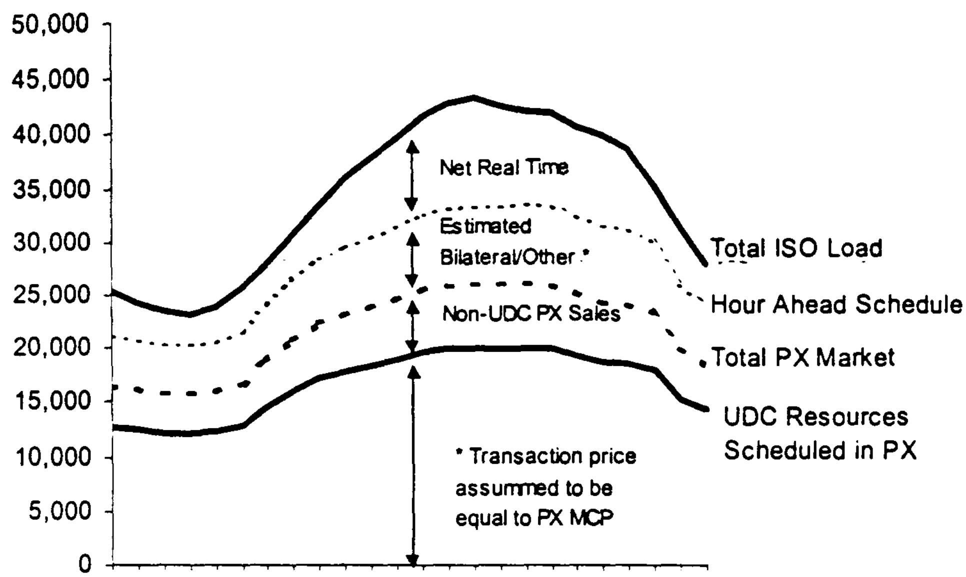
The analysis presented in this report is specifically designed to identify the amount of these potential excess revenues that may have occurred each month in the PX and ISO markets, including the monthly amounts attributable to each individual seller and the amount of FERC jurisdictional and non-jurisdictional transactions in each of these markets. This study builds upon previous analysis of the competitive baseline price for the ISO system, but applies these results using a "bottom up" accounting and analysis of hourly market energy schedules and sales by each individual market participant.

Figure 1 provides a discussion of the "bottom up", transaction level approach used in this study in comparison with the "top down" system-level approach used in previous studies. Figure 2 provides a more detailed overview of the schedule and transaction level approach used in this study. As shown in Figure 2, the approach estimates excess revenues earned by individual suppliers due to uncompetitively high prices in California's different wholesale energy markets in terms several major segments:

- The amount of non-UDC generation sold in the PX market.
- The amount of other non-UDC generation scheduled in the ISO's final Hour Ahead Market through bilateral transactions and other markets.
- The ISO's real time energy market, in which all demand not met by scheduled energy is met.
- The ISO's Ancillary Service capacity market, which is closely related to the Day Ahead energy and real time markets.

[2] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market*, March 2001, Prepared by Eric Hildebrandt, Department of Market Analysis. Submitted as Attachment B to the ISO's *Comments on FERC Staff's Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market*, March 22, 2001.

Figure 1-1. Total ISO System Load by Wholesale Energy Market Segment

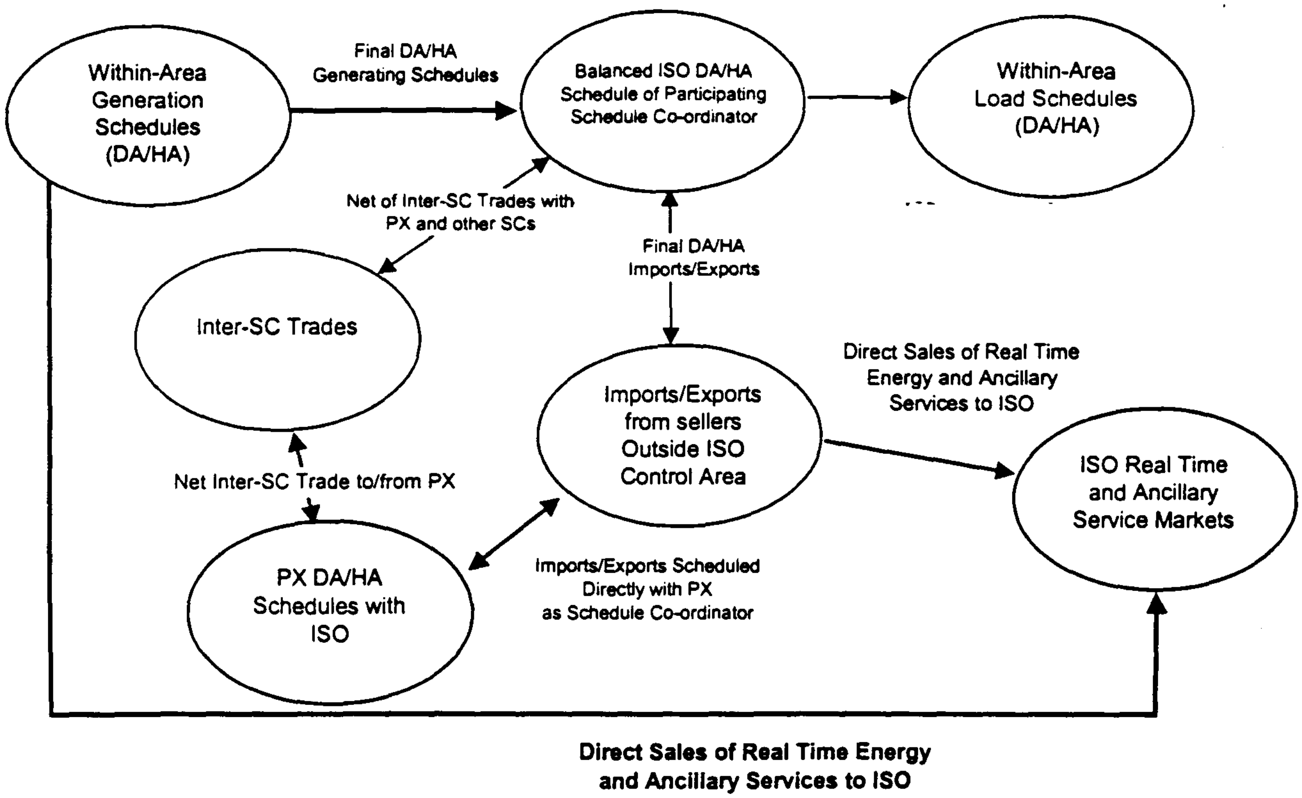


The figure above illustrates the major segments of California's wholesale energy market, and helps to illustrate the methodology used in this study and a previous DMA studies submitted to the Commission to estimate the total magnitude of excess revenues earned by specific suppliers due to uncompetitively high prices.

Like previous analyses submitted to the Commission, this study builds upon estimates of the hourly competitive baseline price for the ISO system given hourly load and supply conditions, spot market gas prices, and other factors that could be expected to affect system marginal costs under competitive market conditions. In previous analyses, however, the total potential impacts of market power in California's wholesale markets were estimated by extrapolating results of this analysis to the entire ISO system based on hourly system-level schedules, loads and prices. With this approach, the total revenue impact due to differences between actual market prices and the competitive baseline prices was estimated by simply multiplying these price differences by the total quantity of system load not met by UDC generation.

In this study, each individual transaction or schedule in the ISO system was used to calculate the excess revenues earned due to actual market prices in excess of the hourly competitive baseline prices developed as part of a previous DMA filing with the Commission. As shown in this report, results of this more detailed "bottom up" approach and the "top down" approach used yield very similar estimates of the total economic impact of uncompetitively high wholesale energy prices. However, the more detailed "bottom-up" approach used in this study allows an accounting of these impacts in terms of excess revenues earned by each supplier due to uncompetitive market outcomes as a result of specific market schedules and transactions.

Figure 1-2. Transaction, Scheduling and Revenue Flows in ISO System



The figure above depicts the major flows of schedules, market transactions and revenues into and within the ISO system, and helps to illustrate the methodology used in this study to estimate the excess revenues earned by different sellers due to the uncompetitively high prices in the wholesale energy markets.

Revenues earned in excess of the competitive baseline price from sales of real time energy and ancillary services directly to the ISO are relatively straight forward to calculate based on market prices and hourly scheduling and dispatch records of the ISO. As indicated by the figure above, these sales come directly from generating units within the ISO system and supplies scheduled from outside the control area over interties. Since these are direct transactions with the ISO, actual prices received for these energy and ancillary services can be calculated and compared to the estimated hourly competitive baseline prices used throughout this analysis.

Since bidding in the PX, scheduling of generation units and imports/exports, and trades between Scheduling Coordinators (inter-SC trades) are all performed on a pooled, or "portfolio" basis, sales in the PX are not as easily tracked. In this study, sales in the PX by each participant were estimated based on net hourly inter-SC trades to the PX from other Scheduling Coordinators. Additional sales of imports into the PX were also identified based on tie-point identification codes, which indicate the source of imports scheduled with the PX as Scheduling Coordinator.

The following sections provide a detailed description of the methodology and algorithms employed in the study, and study results. Since the focus of this study is on excess revenues earned by individual suppliers due to uncompetitively high prices in California's wholesale energy markets, the methodology and results of this study are described from the "supply side" perspective, or in terms of *excess revenues received by suppliers,* rather than in terms of additional costs to consumers.

1.2 Final Hour Ahead Generation Schedules
Of Generation Sources Within ISO System

The excess revenues above competitive levels received by non-UDC generation scheduled with the ISO (either through the PX or through other bilateral arrangements), are estimated in this study by first recalculating the actual value of this energy at market prices, and then comparing this to the revenue that would be received for the same quantify of energy at the hourly competitive market baseline price calculated as part of previous analysis by DMA submitted to the Commission. First, total market energy revenues are estimated for each generating unit in each hour (*t*) by multiplying the final Hour Ahead Energy schedule of each generating unit (*u*) by the Market Clearing Price in the PX Day Ahead market (PX_MCP_t) .

$$\text{Estimated Actual Revenue}_{u,t} = \text{Hour Ahead Energy Schedule}_{u,t} \times PX\_MCP_t$$

Total market energy revenues under competitive market conditions are then estimated by multiplying the final Hour Ahead Energy schedules by the hourly Competitive Baseline Price (CBP_t) calculated as part of the previous analysis of market power in the ISO system:

$$\text{Competitive Baseline Revenue}_{u,t} = \text{Hour Ahead Energy Schedule}_{u,t} \times CBP_t$$

The difference between estimated actual revenues, and estimated revenues under competitive market conditions, represents estimated net revenues in excess of the competitive market baseline:

$$\text{Excess Revenues}_{u,t} = \text{Actual Revenue}_{u,t} - \text{Competitive Baseline Revenues}_{u,t}$$

The hourly total revenues and total scheduled generation associated with these excess revenues are calculated for each market participant (or Scheduling Coordinator) using the same basic equation above. Generation resources owned or under contract to the state three major UDCs are excluded from this calculation to reflect the assumption that any revenues in excess of competitive levels earned by these resources is ultimately "netted out" of any costs passed on to consumers.

The total portion of these excess revenues attributable to sales in the PX market is estimated in this study based on the quantify of scheduled generation transferred to the PX through inter-Scheduling Coordinator trades (inter-SC trades) scheduled with the ISO. This analysis is discussed in the section below on *Energy Sales in the PX Market.*

1.3 Final Hour-Ahead Import/Export Schedules

Hourly calculations for supply resources scheduled within the ISO system are combined with similar calculations for net import/export schedules to provide a "bottom up" calculation of total market revenues in excess of competitive levels associated with the total volume of import and exports scheduled into the ISO system. Revenues from any imports schedules submitted to the ISO by each market participant u are estimated by applying the same equations described above to import schedules (*i*):

$$\text{Estimated Import Revenue}_{,p,t} = \text{Hour Ahead Import Schedule}_{p,t} \times \text{PX\_MCP}_t$$

$$\text{Competitive Import Revenue}_{p,t} = \text{Hour Ahead Energy Schedule}_{p,t} \times \text{CBP}_t$$

$$\text{Excess Import Revenues}_{p,t} = \sum \text{Estimated Import Revenue}_{p,t} - \text{Competitive Import Revenue}_{p,t}$$

Revenues from any export schedules submitted to the ISO by each market participant u are estimated by applying the same equations described above to export schedules (*i*):

$$\text{Estimated Export Payments}_{p,t} = \text{Hour Ahead Export Schedule}_{p,t} \times \text{PX\_MCP}_t$$

$$\text{Competitive Export Payments}_{p,t} = \text{Hour Ahead Export Schedule}_{p,t} \times \text{CBP}_t$$

$$\text{Excess Export Payments}_{p,t} = \sum \text{Estimated Export Revenue}_{p,t} - \text{Competitive Export Revenue}_{p,t}$$

Scheduled exports are valued in this initial calculation at the PX MCP for each hour in keeping with the approach of using the PX price as the best proxy for valuing wholesale energy scheduled in the ISO system that is not directly transacted in the ISO or PX market. In the case of imports and exports, this approach effectively "nets out" a significant portion of Excess Import Revenues with Excess Export Payments at similarly high prices. A more detailed investigation, based on actual data on bilateral transactions, may show a different level of net excess payments for imports/exports above the competitive baseline price.

In practice, market participants may either self-schedule exports/imports by acting as their own Scheduling Coordinator, or may schedule exports/imports through another Scheduling Coordinator such as the PX or Automated PX (APX). The DMA has developed the means to electronically identify most entities scheduling import/exports through the PX based on the inter-tie identification codes. In this study, any imports/exports scheduled with the ISO by market participants through the PX are included with other market activity of that market participant for purposes of identifying market transactions subject to potential refunds, as discussed the section below on *Energy Sales in the PX Market*.

1.4 Total Hour Ahead Schedules

The total net impact of market energy prices in excess of competitive levels for energy scheduled with the ISO can then be estimated for any time period and group of market participants in terms of revenues earned by suppliers as follows:

Net Excess for Scheduled Energy$_{p,t}$ = Excess Revenues Received by Within-Area Resources$_{u,t}$
+ Excess Import Revenues$_{p,t}$
- Excess Export Payments$_{p,t}$

As in previous studies of total potential system level impacts of uncompetively high prices, supply sources owned or under contract to the state's major UDCs are not included in this summation. Also, this study provides a summation of results by sellers considered by FERC to be jurisdictional and non-jurisdictional. Summary results of this summation are shown in Table 2-1.

1.5 Energy Sales in the PX Market

The total portion of these excess revenues from scheduled energy attributable to sales in the PX market is estimated based on the quantify of generation transferred to the PX through inter-Scheduling Coordinator trades (inter-SC trades), which are scheduled with the ISO as part of the process through which each SC meets the ISO requirement for balanced Day Ahead and Hour Ahead load and generation schedules. In addition to providing a mechanism for generators and marketers to schedule generation sold in the PX against load purchasing energy in the PX, inter-SC trades provide a means for a wide range of bi-lateral transactions and transfers of load and generation. During most hours, actual inter-SC trades represent a complex "daisy chain" of transfers among the resource portfolios of different participants, including transfers of supply from generators or marketers to the PX, representing supply sold to buyers in the PX market.

The net quantity of generation sold by individual market participants (acting as their own Scheduling Coordinators) in the PX market can be calculated by summing up the total amount of generation transferred from the participants' supply portfolio to the PX:

Net PX Sales Quantity $_{SC,t}$ = Σ Transfer of Supply from SC to PX $_{SC,PX,t}$
− Transfer of Supply from PX to PX $_{PX,SC,t}$

The revenues from sales of energy in the PX at prices in excess of competitive levels may then be calculated as follows:

PX Revenue$_{SC,t}$ = Net PX Sales Quantity $_{SC,t}$ × PX_MCP$_t$

Competitive Baseline Revenue$_{SC,t}$ = Net PX Sales Quantity $_{SC,t}$

$$\times \text{Min}(CBP_t, PX\_MCP_t)$$

$$\text{Excess Revenues}_{SC,t} = \text{PX Revenue}_{SC,t} - \text{Competitive Baseline Revenues}_{SC,t}$$

We note that this approach has been employed to develop an initial estimate of excess revenues by individual participants' sales in the PX market. Additional analysis based on actual PX data is needed to confirm these results.

Also, as noted above, market participants may either self-schedule exports/imports by acting as their own Scheduling Coordinator, or may schedule exports/imports through the PX as their Scheduling Coordinator. The DMA has developed the means to electronically identify most entities scheduling import/exports through the PX based on the inter-tie identification codes. In this study, any imports/exports scheduled with the ISO by market participants through the PX are included with other market activity of that market participant for purposes of identifying market transactions subject to potential refunds.

1.6 Energy Purchased in the ISO Real Time Energy Market

Any load not met by final Hour Ahead generation schedules submitted to the ISO is met by real time imbalance energy purchased directly by the ISO on behalf of Scheduling Coordinators serving load. For purposes of this study, the real time market is defined as including out-of-market purchases by the ISO, as well as any energy dispatched through the hourly imbalance market. Since December 8, 2000, the real time market also includes sales above the \$250/\$150 "soft caps", which may be paid on an "as-bid" basis, but are subject to cost review and refund by FERC.

The excess revenues above competitive levels in the real time market are estimated in this study by first recalculating the actual price of this energy, and then comparing it to the price of the same quantity of energy at the hourly competitive market baseline price calculated as part of the previous analysis by DMA submitted to the Commission. First, total real time energy revenues earned by each generating unit (or real time import) are calculated for each hourly dispatch by multiplying the incremental quantity dispatched by the hourly real time imbalance energy price:

$$\text{Actual Revenue}_{u,t} = \text{Dispatched MW}_{u,t} \times \text{Real Time Price}_t$$

For purchases made out-of-market or at prices above the "soft cap", the bid or purchase price of these transactions is used in place of the real time imbalance price. The price of energy at the hourly competitive market baseline price calculated as part of previous analysis submitted to the Commission is then calculated as follows:

$$\text{Competitive Baseline Revenue}_{u,t} = \text{Dispatched MW}_{u,t} \times \text{Min}(CBP_t, \text{Real Time Price}_t)$$

The difference between estimated actual revenues and revenues under competitive market conditions represents estimated net revenues in excess of the competitive market baseline:

$$\text{Excess Real Time Energy Revenues}_{u,t} = \text{Actual Revenue}_{u,t} - \text{Competitive Baseline Revenues}_{u,t}$$

Total market revenues and any excess revenues earned due to uncompetitively high prices earned by each generating unit or importer in each hour are then calculated based on the summation of generation dispatched from all units or import schedules owned/scheduled by each market participant.

1.7 ISO Ancillary Service Capacity Markets

Experience – as well as economic theory – shows that under competitive market conditions the prices of Ancillary Service (A/S) capacity purchased directly by the ISO would be expected to be highly correlated with energy market prices, particularly during periods of high prices and market power, but should rarely exceed the price of energy. In addition, since these prices represent specific transactions in the ISO market, this study includes calculation of the degree to which the prices of Ancillary Service capacity purchased directly by the ISO have been increased by the exercise of market power in California's wholesale market.

Specifically, we have assumed that in a competitive market the price of Ancillary Service capacity would not exceed the hourly competitive market baseline energy price used throughout this study, so that:

$$\text{Actual A/S Capacity Payment}_{u,t} = \text{Final A/S Schedule}_{i,t} \times \text{MCP}_t$$

$$\text{Competitive A/S Capacity Payment}_{u,t} = \text{Final A/S Schedule}_{i,t} \times \text{Min}(\text{CBP}_t\,,\ \text{MCP}_t)$$

$$\text{Excess A/S Capacity Payments}_{u,t} = \text{Actual A/S Capacity Payment}_{u,t} - \text{Competitive A/S Capacity Payment}_{u,t}$$

It should be noted that this approach allows payments for A/S Capacity in excess of the competitive baseline energy price, since units providing A/S capacity also have the opportunity to be dispatched for real time energy and earn the market energy price.

1.8 Excess Revenues Earned by Individual Market Participants In the ISO and PX Markets

The total net impact of market prices in excess of competitive levels, or *net system level markup*, can then be estimated for any time period and group of market participants in terms of revenues earned by suppliers as follows:

Total Excess Revenues$_{p,t}$ = Net Excess for Scheduled Energy$_{p,t}$
+ Excess Real Time Energy Revenues $_{u,t}$
+ Excess A/S Capacity Revenues$_{u,t}$

As in previous studies of total potential system level impacts of uncompetively high prices, supply sources owned or under contract to the state's major UDCs are not included in this summation. Also, this study provides a summation of results by sellers considered by FERC to be jurisdictional and non-jurisdictional.

II. Aggregate Summary Results

- As shown in Table 2-1, the total net potential excess revenue for energy scheduled in Final Hour Schedules submitted to the ISO (excluding UDC generation) is estimated at about $4.3 billion over the period May 200 to February 2001. Based on inter-SC trades to the PX and imports from non-UDC participants scheduled through the PX as the Scheduling Coordinator, we estimate that at least $1.5 billion of these revenues are directly attributable to sales in the PX market. The remaining $2.7 billion represents potential bilateral market activity and self-supply by non-UDCs, represented by final Hour Ahead Energy schedules submitted by different Scheduling Coordinators.

- Table 2-2 and Table 2-3 show analysis of Final Hour Ahead resource and import/export schedules combined with analysis of direct sales in the ISO real time energy and Ancillary Service markets. As shown in Table 2-2, results of this analysis indicate total potential revenues in excess of competitive levels for the total wholesale market in excess of $6.7 billion. Previous estimates did not include Ancillary Service markets, which account for about $430 million of total potential excess revenues identified in this study (see Table 2-2).

- A total of about $4 billion of the $6.7 billion of potential excess revenues identified in this study can be tied directly to specific schedules and transactions in the PX and ISO markets (Table 2-3). In addition to about $1.5 billion of potential excess revenues in the PX market, about $2.4 billion of these excess revenues involve sales in the ISO's markets. About $1.9 billion of these excess revenues were incurred in the real time energy market, and about $460 million incurred in the Ancillary Service market.

- Of these $4 billion of excess revenues from transactions in the PX and ISO markets, approximately $3 billion involves sales by entities directly under FERC jurisdiction and holding market-based rate authority (see Figure 2-4). About $1 billion involves transactions by public entities and other participants not under FERC jurisdiction. Tables 2-5 through 2-9 provide more detailed summaries of monthly revenues in excess of competitive levels broken down by FERC jurisdictional and non-FERC jurisdictional entities.

Table 2-1. Summary of Analysis of Based on Individual Hour Ahead Schedules

		Within Control Area		Scheduled Imports		Scheduled Exports		System		
Month	Type	HA Revenue	Excess	HA Revenue	Excess	HA Payments	Excess	Total	Excess	Percent
2000.05	UDC	$527,353,135	$42,481,275	$143,000,000	$18,524,405	-$36,000,000	-$4,395,009	$634,353,135	$56,610,671	9%
2000.06	UDC	1,362,216,994	754,793,309	359,000,000	202,000,000	-110,000,000	-61,000,000	1,611,216,994	895,793,309	56%
2000.07	UDC	1,060,446,285	350,636,326	303,000,000	113,000,000	-100,000,000	-44,000,000	1,263,446,285	419,636,326	33%
2000.08	UDC	1,610,719,040	470,917,057	435,000,000	142,000,000	-150,000,000	-54,000,000	1,895,719,040	558,917,057	29%
2000.09	UDC	1,009,662,518	157,158,336	287,000,000	43,282,945	-100,000,000	-17,000,000	1,196,662,518	183,441,281	15%
2000.10	UDC	775,752,837	166,503,631	232,000,000	46,208,714	-70,000,000	-13,000,000	937,752,837	199,712,345	21%
2000.11	UDC	1,216,144,714	136,891,571	346,000,000	26,080,751	-170,000,000	-21,000,000	1,392,144,714	141,972,322	10%
2000.12	UDC	3,639,552,591	1,029,000,000	559,000,000	-140,000,000	-260,000,000	44,496,095	3,938,552,591	933,496,095	24%
2001.01	UDC	2,248,451,062	843,510,426	654,000,000	221,000,000	-270,000,000	-97,000,000	2,632,451,062	967,510,426	37%
2001.02	UDC	2,445,376,031	699,985,825	728,000,000	206,000,000	-320,000,000	-98,000,000	2,853,376,031	807,985,825	28%
	Sub-total	$15,895,675,207	$4,651,877,756	$4,046,000,000	$878,096,815	-$1,586,000,000	-$364,898,914	$18,355,675,207	$5,165,075,657	28%
2000.05	non-FERC	$109,137,242	$7,082,791	$69,199,322	$6,153,108	-$5,216,460	$961,042	$173,120,104	$14,196,940	8%
2000.06	non-FERC	330,857,981	199,767,099	132,000,000	73,660,097	-22,000,000	-6,922,472	440,857,981	266,504,724	60%
2000.07	non-FERC	219,493,362	63,079,649	129,000,000	49,069,139	-9,547,254	-540,371	338,946,108	111,608,417	33%
2000.08	non-FERC	326,995,398	91,197,836	168,000,000	55,628,707	-35,000,000	-8,206,310	459,995,398	138,620,233	30%
2000.09	non-FERC	184,466,455	34,771,234	115,000,000	19,111,184	-7,706,704	668,655	291,759,751	54,551,073	19%
2000.10	non-FERC	155,902,505	45,272,250	102,000,000	21,755,647	-4,315,611	-192,672	253,586,894	66,835,225	26%
2000.11	non-FERC	270,860,410	70,090,364	141,000,000	15,872,619	-25,000,000	-1,381,694	386,860,410	84,581,289	22%
2000.12	non-FERC	675,737,104	186,143,089	223,000,000	-38,000,000	-63,000,000	5,993,739	835,737,104	154,136,828	18%
2001.01	non-FERC	455,768,446	167,049,008	233,000,000	77,187,971	-45,000,000	-14,000,000	643,768,446	230,236,979	36%
2001.02	non-FERC	485,163,084	136,180,622	304,000,000	96,449,280	-110,000,000	-32,000,000	679,163,084	200,629,902	30%
	Sub-total	$3,214,381,987	$1,000,633,942	$1,616,199,322	$376,887,752	-$326,786,029	-$55,620,083	$4,503,795,280	$1,321,901,610	29%
2000.05	FERC	228,898,897	41,546,482	65,973,399	13,342,863	-40,000,000	-7,841,400	254,872,296	47,047,945	18%
2000.06	FERC	827,305,007	504,998,446	121,000,000	64,391,094	-180,000,000	-110,000,000	768,305,007	459,389,540	60%
2000.07	FERC	727,199,321	291,395,617	127,000,000	57,338,277	-250,000,000	-110,000,000	604,199,321	238,733,894	40%
2000.08	FERC	1,207,067,469	395,289,099	157,000,000	53,991,589	-410,000,000	-130,000,000	954,067,469	319,280,688	33%
2000.09	FERC	759,706,353	137,954,138	105,000,000	15,997,004	-170,000,000	-23,000,000	694,706,353	130,951,142	19%
2000.10	FERC	583,593,563	130,905,808	129,000,000	27,912,391	-75,000,000	-14,000,000	637,593,563	144,818,199	23%
2000.11	FERC	746,348,144	148,240,296	195,000,000	18,282,429	-140,000,000	-19,000,000	801,348,144	147,522,725	18%
2000.12	FERC	1,526,133,057	460,084,406	207,000,000	-55,000,000	-300,000,000	59,556,074	1,433,133,057	464,640,480	32%
2001.01	FERC	1,553,525,316	586,388,629	152,000,000	58,089,433	-170,000,000	-50,000,000	1,535,525,316	594,478,062	39%
2001.02	FERC	1,800,828,585	476,784,511	231,000,000	74,891,600	-280,000,000	-83,000,000	1,751,828,585	468,676,111	27%
	Sub-total	$9,960,605,712	$3,173,587,432	$1,489,973,399	$329,236,680	-$2,015,000,000	-$487,285,326	$9,435,579,111	$3,015,538,786	32%
System Total		$29,070,662,906	$8,826,099,130	$7,152,172,721	$1,584,221,247	-$3,927,786,029	-$907,804,323	$32,295,049,598	$9,502,516,053	29%
Non-UDC Totals		$13,174,987,699	$4,174,221,374	$3,106,172,721	$706,124,432	-$2,341,786,029	-$542,905,409	$13,939,374,391	$4,337,440,396	31%

Table 2-2. Total Estimated Wholesale Revenues Above Competitive Market Baseline

Non-UDC Market Participants Only (Millions of Dollars)

	Final Hour Energy Schedules		ISO Real Time Energy Purchases		ISO Ancillary Services Market		ISO System Total	
May	$61	18%	$40	50%	$21	55%	$123	27%
June	$726	63%	$223	81%	$289	85%	$1,237	70%
July	$350	37%	$112	61%	$33	37%	$495	41%
Aug	$458	30%	$193	42%	$48	23%	$698	32%
Sept	$186	20%	$130	45%	$26	23%	$341	25%
Oct	$212	29%	$67	55%	$2	6%	$281	31%
Nov	$232	23%	$132	37%	$4	6%	$368	25%
Dec	$619	28%	$376	33%	$8	2%	$1,003	27%
Jan	$825	41%	$309	43%	$3	1%	$1,137	39%
Feb	$669	29%	$346	37%	$6	5%	$1,022	31%
May-Sept	$1,781	34%	$698	54%	$416	53%	$2,896	40%
Oct-Feb	$2,557	26%	$1,231	38%	$23	3%	$3,810	28%
Total	$4,337	29%	$1,929	42%	$439	29%	$6,706	32%

Revenues in excess of competitive levels in non-ISO energy markets estimated by multiplying Total Hour Ahead Energy Schedules for non-UDC generation resources with control area plus non-UDC import/export by difference between PX MCP and estimated hourly competitive baseline price.

Numbers in parentheses represent excess revenues as percent of total marketrevenues.

Table 2-3. Total Estimated Revenues Above Competitive Market Baseline

PX and ISO Market Transactions/Schedules

Non-UDC Market Participants Only (Millions of Dollars)

	PX Market Transactions (Estimated)		ISO Real Time Energy Purchases		ISO Ancillary Services Market		Total	
May	$52	30%	$40	50%	$21	55%	$114	39%
June	$369	61%	$223	81%	$289	85%	$880	72%
July	$198	40%	$112	61%	$33	37%	$343	45%
Aug	$220	35%	$193	42%	$48	23%	$461	36%
Sept	$107	23%	$130	45%	$26	23%	$263	30%
Oct	$102	25%	$67	55%	$2	6%	$171	31%
Nov	$132	24%	$132	37%	$4	6%	$268	27%
Dec	$138	25%	$376	33%	$8	2%	$522	26%
Jan	$273	43%	$309	43%	$3	1%	$585	38%
Feb	$0	0%	$346	37%	$6	5%	$352	33%
May-Sept	$946	40%	$698	54%	$416	53%	$2,061	47%
Oct-Feb	$644	30%	$1,231	38%	$23	3%	$1,898	31%
Total	$1,590	35%	$1,929	42%	$439	29%	$3,958	37%

Numbers is parentheses represent excess revenues as percent of total market revenues.

Table 2-4. Total Estimated Revenues Above Competitive Market Baseline

PX and ISO Market Transactions/Schedules

FERC Jurisditional / Non-UDC Market Participants Only
(Millions of Dollars)

	PX Market Transactions (Estimated)		ISO Real Time Energy Purchases		ISO Ancillary Services Market		Total	
May	$48	31%	$30	50%	$17	58%	$95	39%
June	$341	61%	$185	81%	$243	86%	$770	72%
July	$174	40%	$85	61%	$27	39%	$287	45%
Aug	$198	35%	$147	44%	$38	23%	$382	36%
Sept	$95	23%	$106	48%	$24	25%	$225	31%
Oct	$91	26%	$56	56%	$2	7%	$149	31%
Nov	$122	25%	$112	37%	$4	6%	$237	28%
Dec	$140	25%	$311	33%	$7	3%	$458	26%
Jan	$223	43%	$146	39%	$2	2%	$372	36%
Feb	$0	0%	$107	32%	$6	5%	$114	25%
May-Sept	$856	41%	$554	56%	$349	55%	$1,758	47%
Oct-Feb	$575	30%	$732	36%	$21	3%	$1,329	29%
Total	$1,431	35%	$1,286	42%	$370	29%	$3,087	37%

Numbers is parentheses represent excess revenues as percent of total market revenues.

Table 2-5. Final Hour Ahead Energy Schedules
Estimated Revenues Above Competitive Baseline (Millions of Dollars)

	Non-UDC Market Participants					
	FERC Jurisdictional		non-FERC		Total	
May	$47	18%	$14	8%	$61	18%
June	$459	60%	$267	60%	$726	63%
July	$239	40%	$112	33%	$350	37%
Aug	$319	33%	$139	30%	$458	30%
Sept	$131	19%	$55	19%	$186	20%
Oct	$145	23%	$67	26%	$212	29%
Nov	$148	18%	$85	22%	$232	23%
Dec	$465	32%	$154	18%	$619	28%
Jan	$594	39%	$230	36%	$825	41%
Feb	$469	27%	$201	30%	$669	29%
May-Sept	$1,195	32%	$585	50%	$1,781	34%
Oct-Feb	$1,820	29%	$736	36%	$2,557	26%
Total	$3,016	30%	$1,322	41%	$4,337	29%

Table 2-6. Sales in PX Market (Inter-SC Trades to PX)
Estimated Revenues Above Competitive Baseline (Millions of Dollars)

	Non-UDC Market Participants					
	FERC		non-FERC		Total	
May	$38	31%	$1	20%	$40	30%
June	$293	61%	$7	55%	$300	61%
July	$151	40%	$4	33%	$155	40%
Aug	$177	35%	$4	29%	$181	35%
Sept	$80	23%	$3	18%	$83	23%
Oct	$74	26%	$5	21%	$79	25%
Nov	$105	25%	$5	17%	$111	24%
Dec	$153	25%	$5	15%	$158	25%
Jan	$197	43%	$29	38%	$226	43%
Feb	$0	0%	$0	0%	$0	0%
May-Sept	$740	41%	$19	31%	$759	40%
Oct-Feb	$529	30%	$45	27%	$573	30%
Total	$1,269	35%	$64	28%	$1,332	35%

Table 2-7. Imports into PX Market (Scheduled with PX as Schedule Coordinator) Estimated Revenues Above Competitive Baseline (Millions of Dollars)

Non-UDC Market Participants

	FERC	non-FERC	Total
May	$10	$3	$12
June	$48	$20	$68
July	$23	$21	$43
Aug	$21	$19	$40
Sept	$15	$9	$24
Oct	$17	$6	$23
Nov	$17	$5	$21
Dec	-$13	-$8	-$20
Jan	$26	$20	$46
Feb	$0	$0	$0
May-Sept	$116	$71	$187
Oct-Feb	$47	$23	$70
Total	$162	$95	$257

Table 2-8. ISO Real Time Energy Market Revenues Above Competitive Baseline (Millions of Dollars)

	Non-UDC Market Participants					
	FERC Jurisdictional		non-FERC		Total	
May	$30	50%	$10	50%	$40	50%
June	$185	81%	$38	80%	$223	81%
July	$85	61%	$27	59%	$112	61%
Aug	$147	44%	$46	39%	$193	42%
Sept	$106	48%	$24	36%	$130	45%
Oct	$56	56%	$11	54%	$67	55%
Nov	$112	37%	$20	35%	$132	37%
Dec	$311	33%	$66	34%	$376	33%
Jan	$146	39%	$163	48%	$309	43%
Feb	$107	32%	$239	40%	$346	37%
May-Sept	$554	56%	$145	49%	$698	54%
Oct-Feb	$732	36%	$499	41%	$1,231	38%
Total	$1,286	42%	$643	43%	$1,929	42%

Table 2-9. ISO Ancillary Service Capacity Markets Revenues Above Competitive Baseline (Millions of Dollars)

	FERC		Non-UDC Market Participants non-FERC		Non-UDC Market Participants Total	
May	$17	58%	$5	47%	$21	55%
June	$243	86%	$46	79%	$289	85%
July	$27	39%	$5	31%	$33	37%
Aug	$38	23%	$10	22%	$48	23%
Sept	$24	25%	$2	12%	$26	23%
Oct	$2	7%	$0	3%	$2	6%
Nov	$4	6%	$1	5%	$4	6%
Dec	$7	3%	$1	2%	$8	2%
Jan	$2	2%	$0	0%	$3	1%
Feb	$6	5%	$0	0%	$6	5%
May-Sept	$349	55%	$68	46%	$416	53%
Oct-Feb	$21	3%	$2	2%	$23	3%
Total	$370	29%	$69	28%	$439	29%