CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

cc: ISO Officers, ISO Board Assistants

Date: April 19, 2002

Re: Market Analysis Report for March 2002

This is a status report only. No Board action is required.

Executive Summary

Prices for incremental energy in the ISO's real-time Balancing Energy Ex-Post Auction Market (BEEP Stack) increased in March, due to the substantial increase in the price of natural gas and the exodus of importers from the real-time market. Gas prices have risen nationally from approximately $2.25 per million British Thermal Units (MMbtu) in late January to over $3.50/MMbtu in late March. This, among other factors, caused regional spot electricity prices to rise from the range of $25-$30 per megawatt-hour (MWh) in early March to a peak above $45/MWh by March 25. Real-time incremental (INC) prices in the ISO's BEEP Stack averaged $51.85/MWh, up 14.4 percent since February. Total cost to load of energy and ancillary services increased to $44/MWh in March, the sixth month in a row that this index has remained in the $40-$50 range.

In an Order issued December 19, 2001, the Federal Energy Regulatory Commission (FERC) directed that energy marketers that bid energy into the BEEP Stack do so at a price of $0/MWh. Immediately after the ISO implemented this direction on February 22, 2002, the volume of import energy that marketers bid into the BEEP Stack dropped sharply from an average of over 1000 MW to approximately 200 MW.

On March 29, FERC issued an Order responding to the ISO's petition for Amendment 42 to its Tariff, rejecting the two main components of the ISO's request for authority to mitigate intrazonal congestion and penalize declines of dispatch instructions. Thus, the ISO continues to face compromises to system reliability, and remains stifled in its ability to penalize declines, resulting in economic withholding and the consequential exercise of market power.

I. Energy Market Statistics

Loads. ISO load totaled 18,749 gigawatt-hours (GWh) in March, up 5.0 percent from March 2001. Peak hourly load for the month was 31,014 MW, up 4.9 percent from the peak of March 2001, a month in which conservation and curtailments were key factors in limiting load. Average hourly load was 25,200 MW in March 2002.

Conservation. The California Energy Commission reports changes in total energy and peak load, adjusted for growth and weather conditions. These changes are an indicator of the level of conservation. The CEC reports that adjusted load increased 7.0 percent in March 2002 compared with March 2001. Peak load increased 4.1 percent for the same period. Load in March 2001 was considerably lower than usual, due to unusually high conservation and interruptible load curtailments. Adjusted total and peak loads in March 2002 were respectively 2.6 percent and 5.5 percent lower than those in March 2000.

Real-Time Prices and Volumes. As noted previously, real-time prices increased substantially between February and March. The increase in the price of natural gas has raised the operating costs of natural gas-fired thermal generators. Meanwhile, the sharp decrease in energy offered by marketers from resources outside the ISO Control Area, due to the zero-bid rule imposed on February 22, has diminished supply.

The ISO procured 30 MWh of energy out of market on the evening of March 17, when BEEP dispatches were not sufficient to meet load. This was the only OOM call during the month. The Department of Water Resources' California Energy Resources Scheduling Division (CERS) has not been involved in real-time procurement since December 2001.

The ISO tracks several key price and volume statistics for real-time energy procured on behalf of load in its control area. The following chart shows (1) average prices and total volumes for real-time energy procured through the BEEP Stack; (2) average prices and total volumes for real-time energy procured in out-of-market transactions, when BEEP energy was not sufficient to meet load; (3) average prices and total volumes for all real-time energy, equal to a weighted average of (1) and (2); and (4) average hourly system load and the percent of underscheduled energy, or proportion of volume that is not scheduled in the forward market and must be procured in real time.

Table 1. Real-Time Energy Statistics for March 2002

	Avg. Market-Clearing Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads and Pct. Underscheduling (4)
	Inc	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	
Peak	$ 53.74 119 GWh	$ 16.19 83 GWh	$ 71.78 *	No Procurement	$ 53.74 119 GWh	$ 16.19 83 GWh	24,453 MW 3%
Off-Peak	$ 43.33 26 GWh	$ 7.85 73 GWh	No Procurement	No Procurement	$ 43.33 26 GWh	$ 7.85 73 GWh	20,198 MW 1%
All Hours	$ 51.84 145 GWh	$ 12.29 156 GWh	$ 71.78 *	No Procurement	$ 51.85 145 GWh	$ 12.29 156 GWh	23,034 MW 2%

* Indicates less than 1 GWh of total procurement for the month.

Average BEEP prices generally increased from February levels. The average BEEP prices for incremental (INC) and decremental (DEC) energy respectively were $51.85/MWh and $12.29/MWh in March. Total BEEP procurement decreased from February levels on an absolute basis, in spite of the longer month. Total INC and DEC volumes were 145 GWh and 156 GWh in March, respectively.

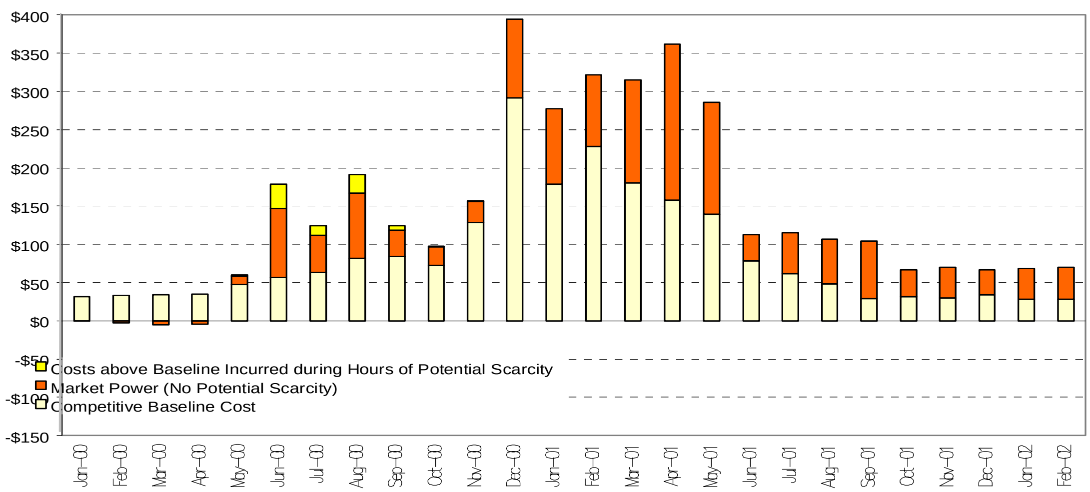
Price Cap Hits. The ISO monitors the frequency in which the BEEP MCP comes within $1 of the current soft price cap, established by FERC in its Orders of June 19, 2001, and December 19, 2001, and fixed at $108/MWh throughout March 2002. The MCP came within $1 of the cap in five of the 1,605 ten-minute pricing intervals during which INC energy was procured in March in Zone NP15. This was the third month in a row in which the ratio of hits to intervals with INC procurement remained below one percent.

The ISO did not procure any real-time energy above the price cap in March.

Market Power. The bulk of the markup of prices above competitive levels in ISO wholesale energy costs is embedded in CERS' long term contracts. Prices for short-term energy, which includes day-ahead and hour-ahead forward contracts, as well as real-time procurement, have fallen toward competitive levels in recent months.

The ISO now tracks three metrics of market power. All of these metrics compare actual prices observed in forward and ISO real-time markets to estimates of prices that would prevail if energy markets were competitive; that is, if prices were equal to economic costs. The first of the following graphs shows the price-to-cost markup embedded in long-term and short-term[1] forward contracts, and real-time procurement. The second graph shows the markup included in the price of short-term energy and real-time procurement. The third graph shows the markup in the price of real-time energy from competitive baseline levels.

Figure 1. Price-to-Cost Markup in Long-Term Forward, Day Ahead, and Real-Time Energy



[1] Long-term forward contracts include energy procured prior to one day before the hour of delivery. Short-term forward contracts include procurement one day ahead and nearer to the hour of delivery.

Figure 2. Price-to-Cost Markup in Short-Term Energy (Day Ahead and Real-time)

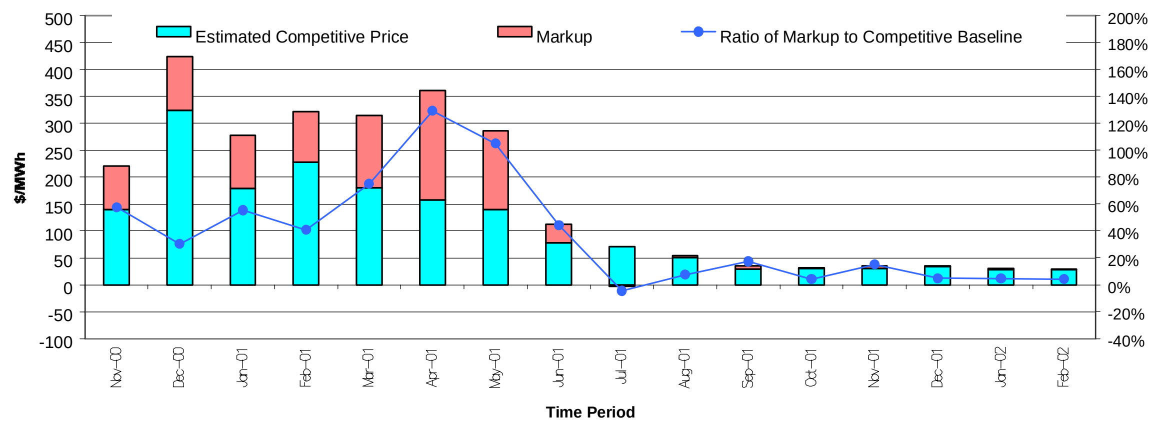
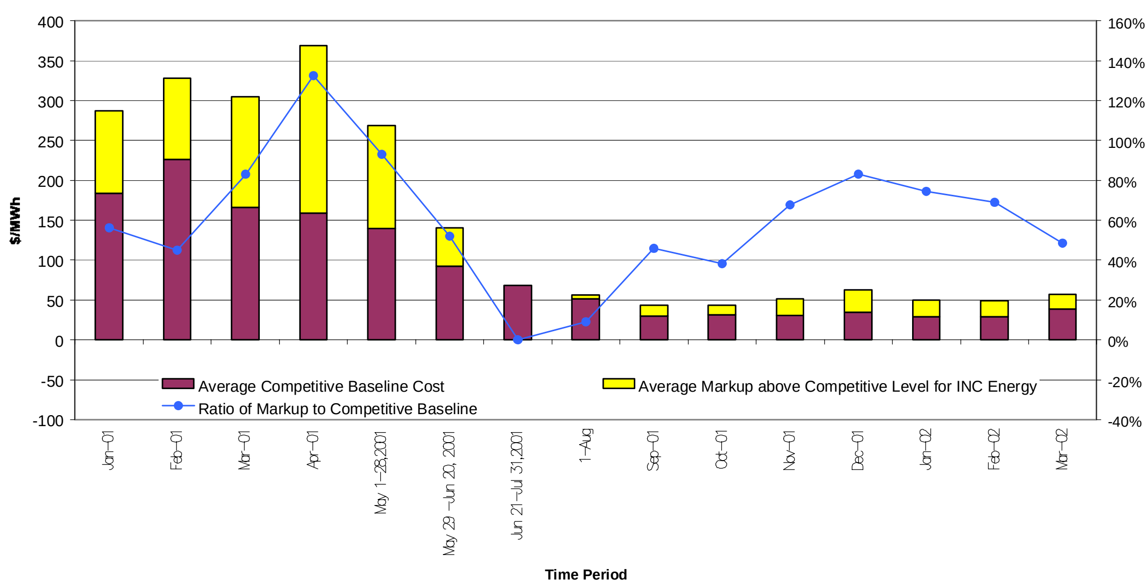


Figure 3. Price-to-Cost Markup in Real-Time Energy



II. Ancillary Services.

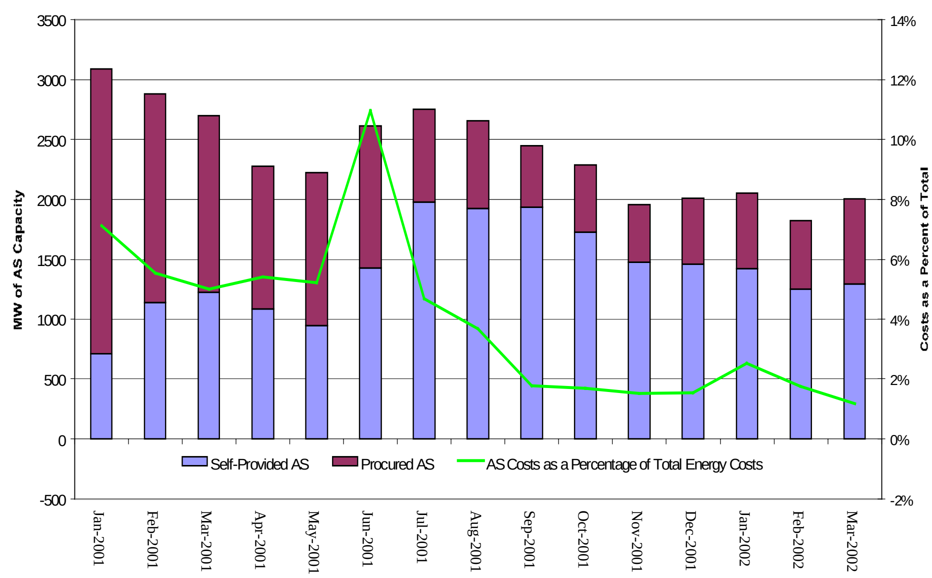
The ISO monitors prices and volumes for ancillary services (AS) by type and market. The average prices of upward and downward regulation services in the day-ahead market were $9.02/MW and $8.35/MW, down approximately 36 percent and 40 percent from February levels, respectively. The volume of market-procured AS has increased to approximately 35 percent of total AS volume, the largest proportion of market volume since July 2001. The cost of ancillary services has continued to decrease as a percentage of energy costs.

The table below shows average prices and volumes for AS by market in March. The following chart shows self-provision of AS, and AS costs as a percentage of total energy costs.

Table 2. Ancillary Services Statistics for March 2002

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 9.02	$ 10.75	$ 9.20	466	53	89%
Regulation Down	$ 8.35	$ 5.92	$ 8.04	450	66	87%
Spin	$ 3.15	$ 3.04	$ 3.15	740	34	95%
Non-Spin	$ 0.57	$ 1.08	$ 0.60	728	44	94%
Replacement	$ 0.09	$ 4.61	$ 2.22	57	51	52%

Figure 4: Self-Provision of Ancillary Services and AS Costs



III. Interzonal Congestion

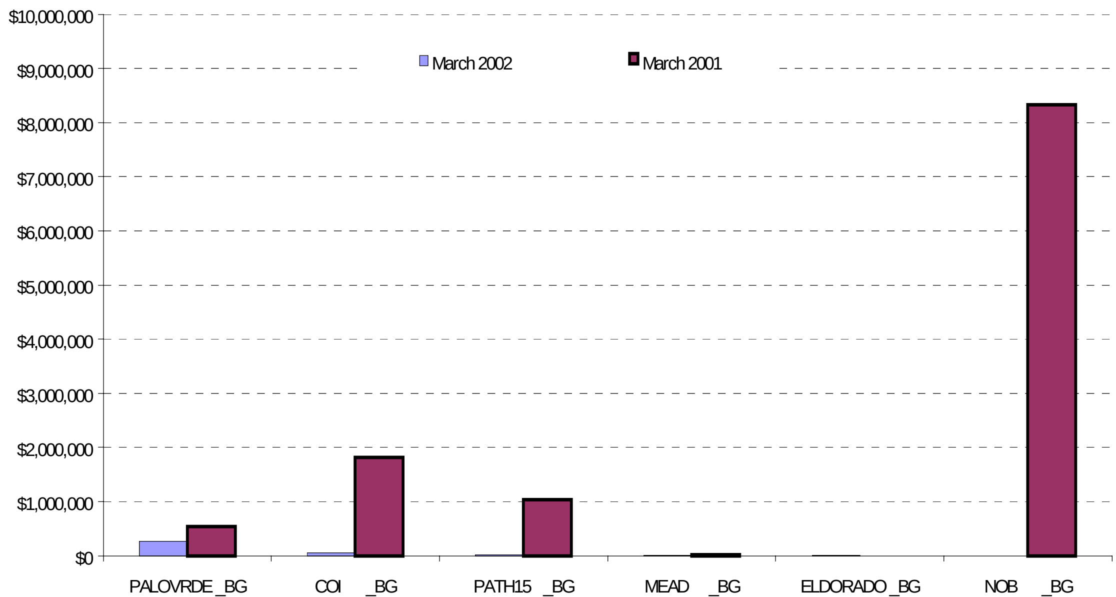
The bulk of interzonal congestion in March occurred in off-peak hours. In the day ahead, Path 15 was congested in four percent of peak hours and over 50 percent of off-peak hours in the import (South-to-North) direction, with an average price of $0.04/MWh, and was not congested in any hours of the month in the export (North to South) direction. Path 15 was also congested in a total of 3 percent of hours in the hour ahead, again in the import direction, with an average price of $15.14/MWh. Eldorado, Palo Verde, Path 26, and Sylmar (AC) were each congested at most one percent of the time in the hour ahead and in the import direction, with average prices of $1.00, $26.87, $49.99, and $247.91/MWh, respectively. Hour-ahead import congestion was present in at most one percent of hours on COI, Eldorado, Mead, Palo Verde, Parker, Path 26, and Sylmar (AC), with average prices of $17.97, $1.41, $18.69, $0.86, $30.00, and $124.98/MWh, respectively. Export congestion was minimal in March, occurring in fewer than one percent of hours on Parker and Path 26 in the day ahead, with average prices of $30.00 and $26.39/MWh, respectively. The table below shows day-ahead congestion frequencies (percent of hours in which the branch group is congested in the specified direction) and prices for March. The following chart compares total congestion costs in March 2002 with those in March 2001, on those paths in which there were substantial congestion costs in either year.

Table 3. Day-Ahead Interzonal Congestion Frequencies and Prices for March 2002

Branch Group	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-hour Cong. Pctg.	Peak Cong. Avg. Price	Off-Peak Cong. Avg. Price	All-hour Avg. Price
Eldorado (Import)	0	2.0	0.7		$ 1.00	$ 1.00
Palo Verde (Import)	0.2	1.61	0.67	$ 99.99	8.59	26.87
Path 15 (South-to-North)	4.4	56.5	21.8	0	0.05	0.04
Path 26 (Import)	0	0.8	0.3		49.99	49.99
Sylmar AC (Import)	0	0.4	0.13		247.91	247.91
Total Interzonal Congestion Costs						$479,359.00

Figure 5. Total Congestion Costs: Day Ahead & Hour Ahead Markets

March 2002 vs. March 2001



The ISO has revised interzonal congestion statistics for the year 2000. These revised statistics are shown in an Appendix at the end of this Report.

IV. Summary of Market Costs

Due to issues concerning the transmission of data from procurers of forward energy to the ISO, the Department of Market Analysis (DMA) includes actual net-short[2] wholesale energy costs on a 45-day-delay basis. Thus, this report contains estimated (rather than actual) net short energy costs for March 2002. Actual net short energy costs will be included in the April report, prior to the May meeting of the Board of Governors. Cost information in the April report may not be consistent with that in the March report, and will supersede it.

DMA estimates that wholesale cost to load for energy and AS totaled $826 million in March, or an average of $44/MWh. Average total costs have remained within the $40-$50 range since October 2001. Costs remain well below the average of $203/MWh seen in the crisis month of March 2001, but above the average of $33/MWh seen in the first two years of operation. The following tables show costs for wholesale energy and AS for 2002 to date and 2001.

[2] Net short energy costs are those costs incurred by CERS to procure energy needed to meet SCE's and PG&E's load requirements not met by those utilities' retained generation.

Table 4a. 2002 Energy Costs

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
JAN-02	19,356	18,940	$ 737	$ 7	$ 19	$ 744	$ 763	$ 38	$ 0.97	2.5%	$ 39
FEB-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 39	$ 0.68	1.7%	$ 40
MAR-02*****	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 44	$ 0.50	1.2%	$ 44
Total 2002	55,259	53,876	2,210	21	40	2,231	2,271				
Avg 2002	18,420	17,959	737	7	13	744	757	40	1	1.8%	$ 41

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund
***** Estimated. Values in April Report will include true-up and may differ from values shown here.

Table 4b. 2001 Energy Costs

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
JAN-01	18,770	16,950	$ 2,710	$ 756	$ 247	$ 3,466	$ 3,713	$ 185	$ 13.15	7.1%	$ 198
FEB-01	16,503	14,876	$ 2,657	$ 917	$ 198	$ 3,574	$ 3,772	$ 217	$ 12.00	5.5%	$ 229
MAR-01	17,857	16,744	$ 2,736	$ 881	$ 181	$ 3,616	$ 3,797	$ 203	$ 10.14	5.0%	$ 213
APR-01	17,237	16,267	$ 2,537	$ 755	$ 178	$ 3,292	$ 3,471	$ 191	$ 10.34	5.4%	$ 201
MAY-01	19,651	18,351	$ 2,771	$ 601	$ 176	$ 3,372	$ 3,548	$ 172	$ 8.97	5.2%	$ 181
JUN-01	19,777	19,468	$ 1,598	$ 111	$ 187	$ 1,709	$ 1,896	$ 86	$ 9.48	11.0%	$ 96
JUL-01	20,976	20,599	$ 1,458	$ 54	$ 71	$ 1,513	$ 1,583	$ 72	$ 3.37	4.7%	$ 75
AUG-01	21,048	21,571	$ 1,329	$ 34	$ 50	$ 1,363	$ 1,414	$ 65	$ 2.38	3.7%	$ 67
SEP-01	19,562	19,562	$ 1,048	$ 20	$ 19	$ 1,067	$ 1,087	$ 55	$ 0.97	1.8%	$ 56
OCT-01	19,105	19,395	$ 863	$ 10	$ 15	$ 873	$ 888	$ 46	$ 0.77	1.7%	$ 46
NOV-01	17,707	18,028	$ 754	$ 10	$ 12	$ 764	$ 776	$ 43	$ 0.66	1.5%	$ 44
DEC-01	18,830	18,673	$ 785	$ 14	$ 12	$ 800	$ 812	$ 42	$ 0.65	1.5%	$ 43
Total 2001	227,024	220,484	21,248	4,162	1,346	25,410	26,756				
Avg 2001	18,919	18,374	1,771	347	112	2,117	2,230	115	6	5.3%	$ 118

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

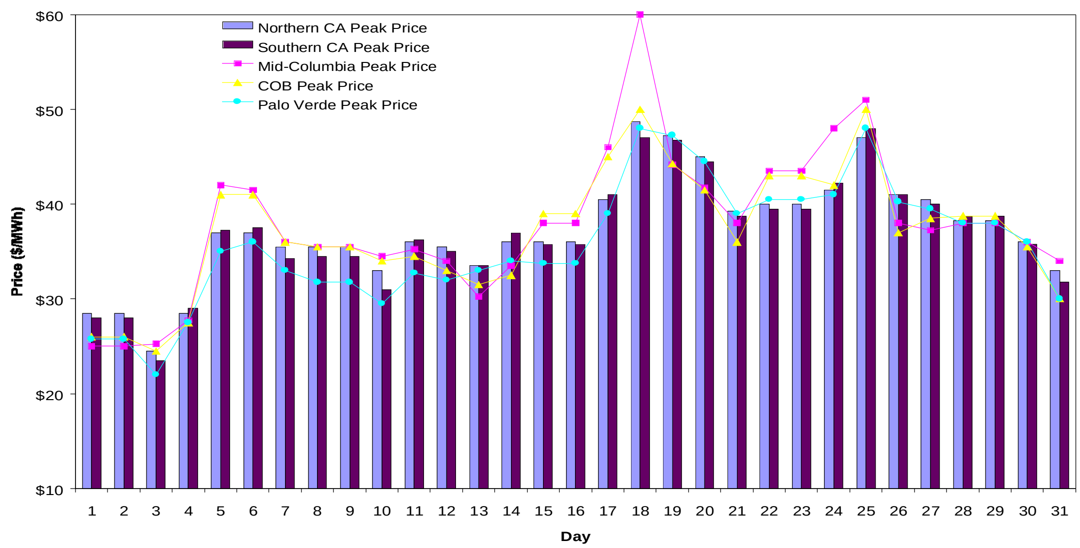
V. Western Regional Electric Bilateral Spot Market

Prices in March increased to highs between 80% and 180% above those at the beginning of the month. Major factors contributing to higher electricity prices throughout the month include intermittent cold weather through much of the continental United States; sharp increases in natural gas spot and futures prices; and lower-than-average hydro flow levels in the Pacific Northwest. The lower-than-average hydro flow levels are a continuing result of last year's drought conditions as reservoirs continue to replenish, with Water Year 2002 flows averaging between 60% and 90% of historical flow averages to date in the Northwest, despite average or above-average precipitation levels and snow pack in much of Washington State. While prices remained around the $25-$30/MWh range between March 1 and March 4, prices spiked to $35-$42/MWh on March 5. This increase was due to both planned and forced outages, and the aforementioned expectation of colder weather (particularly in the South and the Northeast), stronger gas prices, and lower river flows in the Northwest. Units out in the Northwest and in California included Boardman (530 MW), a 50% reduction at Colstrip #4 (700 MW), Huntington #2 (455 MW), El Segundo #3 (330 MW), Haynes #5 (341 MW), and Ormond Beach #1 (725 MW). Warmer weather forecasts caused peak prices to fall on March 7, although continued strength in gas prices and lower-than-average river flows in the Northwest kept prices within the $30-40/MWh range. Existing strength in gas prices and low water levels, combined with a transmission constraint on the California-Oregon Intertie and a false rumor of a 35% reduction at Columbia Generating Station (1,115 MW), caused Northwest peak power prices to increase slightly for March 15 and 16.

Prices increased significantly on March 17 and to monthly highs on March 18, following expectations of colder weather, stronger gas prices, reduced hydroelectric generation, transmission curtailments, and unit outages. Outages and derates included a 20% reduction in generation at Columbia Generating Station (1,115 MW), a reduction at the Big Creek Project (1,020 MW) to 518 MW, and South Bay (240 MW). Prices between March 19 and March 23 declined to the $40/MWh level. Additional strength in natural gas prices caused prices to increase on March 24 and 25, with prices reaching the $48/MWh level by March 25. Milder weather expectations caused prices to decline to the $35-40/MWh level, and, by the end of the month, prices stood between $30-35/MWh.

The following chart shows daily regional prices in and around the ISO Control Area in March.

Figure 6. Western Regional Electricity Bilateral Spot Prices



VI. California Natural Gas Prices

Natural gas spot prices increased substantially over March, following an upward trend, reaching monthly highs in the range of $3.46 to $3.67/MMbtu on March 26. Prices were flat or decreasing through the first six days of March, but increased by $0.25/MMbtu on March 6 and continued to increase until March 9, where prices stabilized at between $2.80 and $3.10/MMbtu. The price increase was attributed to continued cold weather across much of the U.S. and expectation of colder weather in the South and Northeast, and also to stronger futures prices on the New York Mercantile Exchange (NYMEX). As shown in the graph of NYMEX Henry Hub Natural Gas April 2002 Futures contract prices, contract prices remained essentially flat through January and February 2002 at $2.05 to $2.50/MMbtu until March 2002, when prices increased to a high of nearly $3.50/MMbtu by the end of March. Prices remained level from March 9 through March 14, owing to more stable temperatures and adequate supply of natural gas.

Prices increased again from March 14 to 16 on reports of higher natural gas demand owing to an improving economy, strong NYMEX futures prices, and also from effects from fears of crude oil supply disruption as a consequence of political events in the Middle East. Mild weather caused prices in the West to drop back to $3.25/MMbtu levels between March 19 and March 21, but prices increased to $3.50/MMbtu levels on March 22 from continued strength in the futures market. Warm temperatures, particularly in the West, caused prices to drop to $3.25 to$3.40/MMbtu on March 27, with financial markets closed from March 29 to March 31. Average bid week prices for April were $3.41, $3.28, and $3.43 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 50%, 46%, and 45% from March bid week prices.

The following charts show monthly average gas prices for twelve months ending March 2002, March prices for California gas markets, and NYMEX gas future prices in March for April delivery.

Figure 7. Monthly Average Gas Prices – California vs. National
Twelve Months Ending March 2002

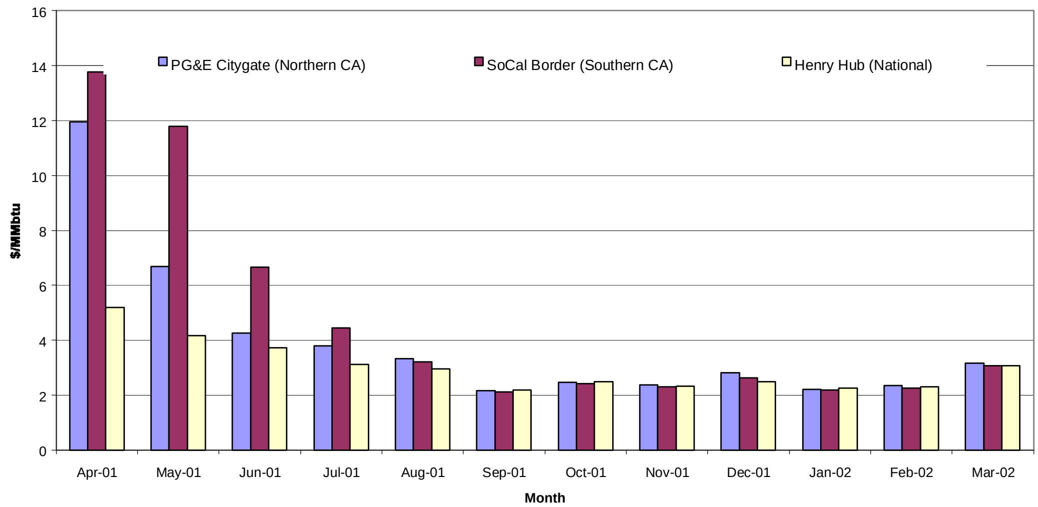


Figure 8. Natural Gas Daily Spot Prices

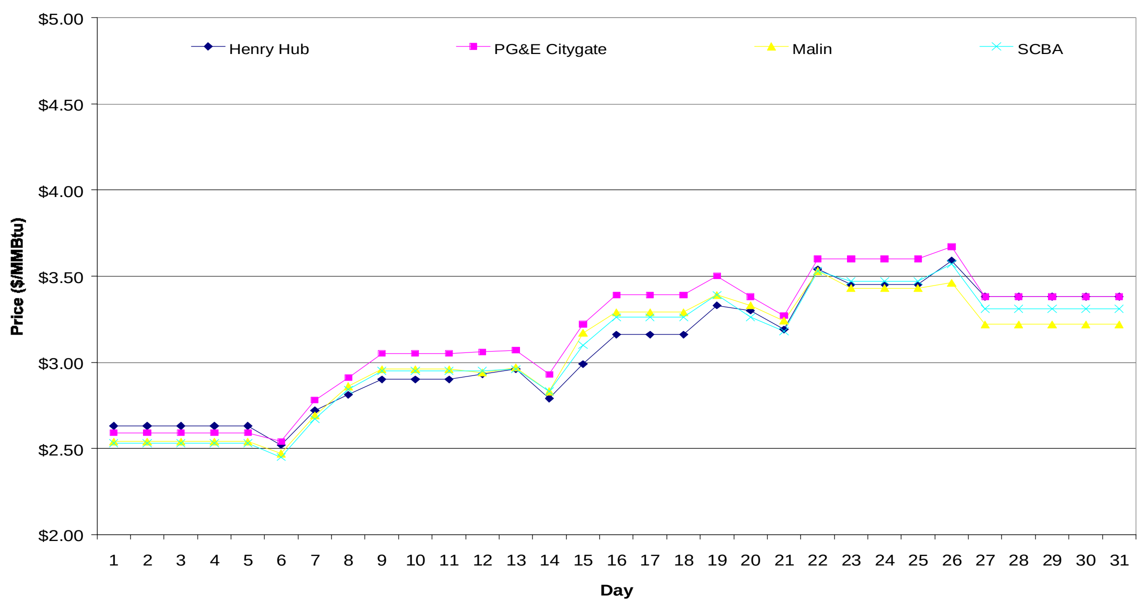
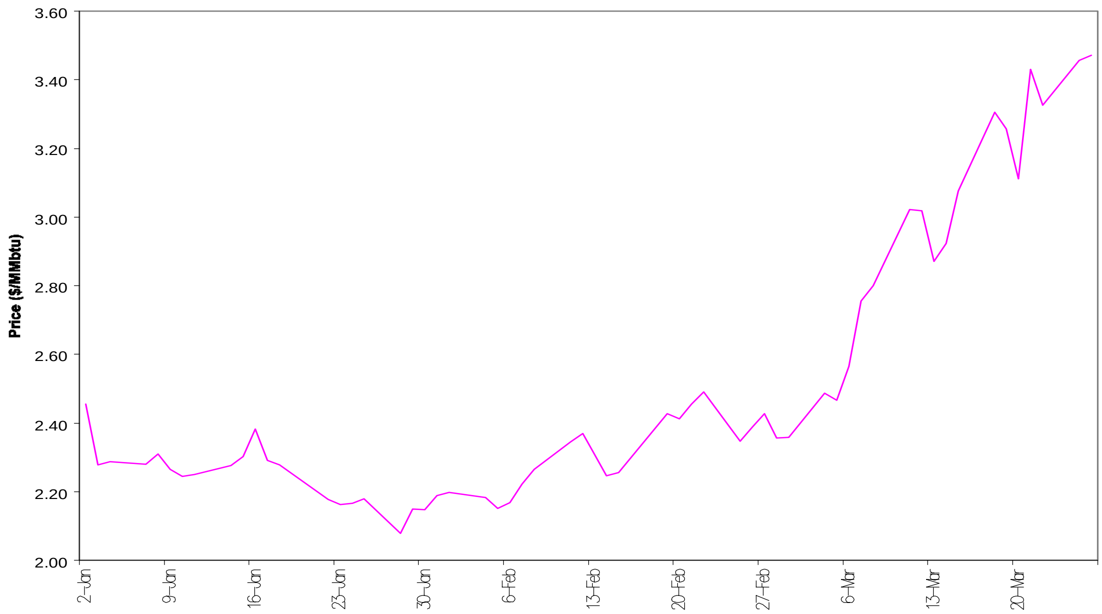


Figure 9. NYMEX Henry Hub Natural Gas Futures April 2002 Contract Prices



VII. Firm Transmission Rights Market

Firm Transmission Rights (FTR) Concentration. No secondary FTR market trades or scheduling coordinator reassignments occurred in March. Hence, FTR ownership concentrations reported in the December 2001 Market Analysis Report for FTRs valid through March 31, 2002, are still in effect. The ownership concentrations reported in the January-February 2002 report for the 2002-2003 FTR cycle also remain unchanged.

FTR Scheduling. FTRs have primarily been used for their financial entitlement to hedge against transmission usage charges. As shown in the following table, a high percentage of FTRs was scheduled on some paths (e.g., 55% on Eldorado, 100% on Silverpeak, and 68% on IID-SCE, all in the import direction). However, the congestion frequencies in the day-ahead and hour-ahead markets are both low. FTR concentration levels do not appear to raise concerns of market manipulation at the present time.

Table 5. FTR Scheduling Statistics

	IMPORT								EXPORT	
	COI	ELDORADO	IID-SCE	MEAD	NOB	PALOVRDE	SILVERPK	VICTVL	COI	PATH26
MW FTR Auctioned	600	707	600	487	523	1819	10	1013	56	1727
Avg. MW FTR Sch.	66	386	407	18	5	728	10	18	3	26
Max MW FTR Sch.	276	480	445	170	50	1111	10	66	25	475
Max Single SC FTR Scheduled	150	355	445	125	50	600	10	55	25	475
% FTR Scheduled	10.97%	54.65%	67.81%	3.69%	1.02%	40.05%	100.00%	1.75%	4.49%	1.48%

* only those paths on which 1% or more of FTRs were attached are listed.

FTR Revenue per Megawatt. FTRs auctioned in January 2001 expired on March 31, 2002. A new cycle of FTRs was auctioned in January, which are in effect from April 1, 2002, to March 31, 2003. The following table summarizes FTR revenue per MW for the 2001 FTR cycle.

Table 6. FTR Revenue Statistics

Export Direction (for Path26 : north to south direction)														
Branch Group	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	cumulative $/MW as of March 31, 2002	Auction Price ($/MW for 12 months)
CFE	0	0	0	0	0	33	0	0	0	0	0	0	33	$233
COI	9,501	365	0	60	0	0	0	0	0	0	0	0	9,926	$47,337
ELDORADO	0	0	0	0	0	0	0	0	0	0	0	0	0	$2,130
MEAD	0	0	0	135	428	0	0	0	0	0	0	0	563	$7,327
NOB	10,412	1,649	312	249	461	0	0	0	0	0	0	0	13,083	$64,069
PALOVRDE	0	0	0	30	0	0	0	0	0	0	0	0	30	$14,100
PATH26	0	0	0	0	0	43	20	101	0	60	4	0	228	$17,724
SILVERPK	0	0	0	0	0	0	0	0	0	0	0	0	0	$28,374
VICTVL	0	0	46	1,371	653	0	0	0	0	0	0	0	2,070	$760
Import Direction (for Path26 : south to north direction)														
CFE	0	0	0	0	0	0	0	0	0	0	0	0	0	$300
COI	0	492	11	0	1,494	1,520	237	28	86	172	28	42	4,112	$3,234
ELDORADO	501	51	125	0	0	26	2	22	60	133	139	5	1,063	$19,028
IID-SCE	0	0	0	0	0	0	2	0	0	0	0	0	2	$625
MEAD	3	0	0	0	0	0	102	244	0	77	43	22	491	$2,386
NOB	0	0	0	0	0	0	0	0	0	0	0	0	0	$3,843
PALOVRDE	752	622	5	0	0	0	2	9,003	2	2,555	742	134	13,816	$6,960
PATH26	6,159	5,828	407	0	0	0	70	997	332	89	0	100	13,982	$2,564
SILVERPK	0	0	0	0	0	0	30	0	0	0	0	0	30	$2,100
VICTVL	0	0	0	0	0	0	0	0	0	0	0	0	0	$168

2001 FTR revenue exceeded the 2001 auction price only on Victorville, COI, Palo Verde, and Path 26, all in the import direction. However, a key important feature of an FTR is that it serves as insurance against the risk that a scheduler must pay congestion charges. FTR holders are also entitled to scheduling priority in the day-ahead market.

VIII. Issues of Note

Rejection of Amendment 42 by FERC. On March 29, FERC issued an Order rejecting certain elements of the ISO's petition for Amendment 42 to its Tariff, which the ISO believes necessary to address well-known flaws in its market design that continue to cause operational problems. Amendment 42 would have included new provisions to mitigate locational market power and increase adherence to ISO dispatch instructions. As a result of the rejection, the ISO continues to lack the authority to mitigate bids for local reliability needs, including intra-zonal congestion, under both normal operating conditions and when transmission facilities are out of service or derated. Suppliers also continue to have the ability to disregard dispatch instructions without penalty, which results in higher real-time costs and compromises the integrity of the ISO's real-time market.

Lack of imports following implementation of FERC zero-bid direction. FERC has sought to inhibit the practice of "Megawatt Laundering," the situation in which an in-state generator evades a price cap by selling electricity to an out-of-state marketer at a high price. The marketer then bids energy into the ISO's real-time market, and uses the high price it paid to support its bid as just and reasonable. In its Order of June 19, 2001, FERC directed that marketers that bid into the BEEP Stack be price-takers; that is, their bids may not set the BEEP MCP. The ISO implemented this provision by allowing the importers to submit bids as price-quantity combinations. The ISO then considered marketers' prices as minimum prices at which they could be dispatched by the BEEP algorithm in economic merit order, but would not use those bids to set the MCP.

In its Order of December 19, 2001, FERC clarified that marketers that choose to offer energy into the BEEP Stack do so at a price of zero. The ISO implemented FERC's clarification on February 22, 2002. DMA found in an investigation that the volume of import energy bid into the BEEP Stack subsequently and immediately diminished from an average of approximately 1200 MWh to approximately 200 MWh. The decrease in import supply has resulted in less competition in the real-time market and could compromise system reliability. The ISO contacted several marketers to supplement the empirical evidence regarding the effect of the zero-bid requirement on import bids. Most marketers confirmed that they could accept being price takers, but the zero-bid requirement increased exposure to price risk by preventing them from being guaranteed a minimum price to supply energy.

There had also been concern that the ISO's other recently-implemented practice of dispatching imports at ten-minute intervals (rather than for full operating hours) would be problematic for the marketers. However, they noted that they have learned to manage this risk by incorporating it into their bid prices, and that it has not had the effect of preventing them from bidding as has the zero-bid requirement.

FERC convened a technical conference on April 4 and 5 to discuss the zero-bid issue, in addition to other market design topics. The Western Power Trading Forum, Independent Energy Producers and California Municipal Utilities Association sponsored a follow-up meeting on the issue on April 11. At these meetings, representatives from the ISO and stakeholders came to a consensus to petition FERC to remove the zero-bid requirement, and to pay ties at the ten-minute INC price for dispatched import bids.

March 26 Report to FERC. DMA contributed to the ISO's comprehensive Third Quarterly Report on mitigation to FERC on March 26, 2002, as requested by FERC in its Order of June 19, 2001. DMA provided the analysis behind the ISO's conclusions that recent moderate prices have largely been a result of factors other than competitive market conditions, which cannot be expected to continue. DMA provided evidence that failure to renew mitigation after it sunsets on September 30, 2002, could result in a return to the dysfunctional conditions of early 2001. DMA's contributions included foundation to an overview of general market conditions, comparisons between ISO prices and regional prices; analyses of market power; and a section on anti-competitive bidding.

Market Design 2002. DMA has been involved in developing the October 1, 2001 market design elements, as well other elements for the ISO's long-term comprehensive market redesign. In particular, DMA has provided leadership in developing the tools for mitigation of market power in both designs, and has been instrumental in steering the design of the Available Capacity (ACAP) requirements.

Path 15 Upgrade. DMA has also been involved in the hearing before the California Public Utilities Commission on whether to upgrade Path 15. Keith Casey, Manager of Market Analysis and Mitigation at the ISO, provided expert testimony in this proceeding. A study completed by DMA that examines the economic benefits from upgrading Path 15 serves as the central item of evidence in this proceeding. Formal hearings in this proceeding concluded on March 26. The ISO submitted final briefs on April 10.

Appendix. Interzonal Congestion Comparison for 2000 and 2001

DMA has revised its interzonal congestion figures for the year 2000. The chart below summarizes the revised congestion frequencies (percentage of hours in which the branch group had congestion in the specified direction) for 2000 compared with 2001. The table that follows is a detailed list of interzonal congestion statistics for 2000. For each branch group that was congested in the specified direction, the table shows total congestion costs, volume of congestion in MWh, congestion frequency, and average congestion price ($/MWh); in all hours, peak hours, and off-peak hours. These figures supersede those from previous reports.

Figure 10. Interzonal Congestion Frequencies for 2000 and 2001

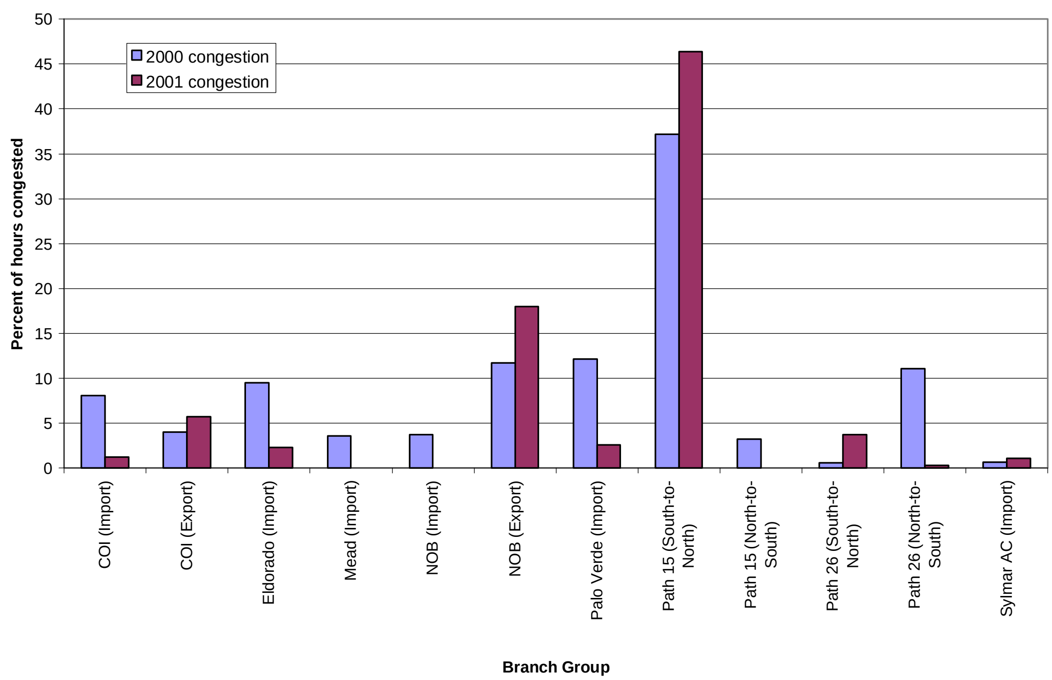


Table 7. Revised Interzonal Congestion Costs, Frequencies, Volumes, and Average Prices for 2000

Branch Group	Direction	All Hours				Peak				Off-Peak			
		Cost	Volume	Cong. Freq..	Avg. Price	Cost	Volume	Cong. Freq..	Avg. Price	Cost	Volume	Cong. Freq..	Avg. Price
Blythe	Import	$ 477	65	0.0%	$ 7.33	$ 477	65	0.0%	$ 7.33	$ -		0.0%	$ -
Cascade	Import	$ 11,450	1,120	0.2%	$ 10.22	$ 11,450	1,120	0.2%	$ 10.22	$ -		0.0%	$ -
Cascade	Export	$ 29,369	511	0.2%	$ 57.53	$ 14,414	480	0.3%	$ 30.00	$ 14,955	30	0.0%	$ 498.00
COI	Import	$ 2,402,990	1,041,758	8.1%	$ 2.31	$ 2,278,231	939,966	11.0%	$ 2.42	$ 124,759	101,792	2.3%	$ 1.23
COI	Export	$ 11,625,261	293,054	4.0%	$ 39.67	$ 9,947,159	236,164	4.7%	$ 42.12	$ 1,678,101	56,889	2.7%	$ 29.50
Eldorado	Import	$ 19,552,996	1,038,296	9.5%	$ 18.83	$ 5,780,096	450,477	6.2%	$ 12.83	$ 13,772,900	587,819	16.2%	$ 23.43
IID-SCE	Import	$ 23,223	774	0.0%	$ 30.00	$ -		0.0%	$ -	$ 23,223	774	0.1%	$ 30.00
IID-SDG&E	Export	$ 122,819	4,094	0.8%	$ 30.00	$ 93,045	3,102	0.9%	$ 30.00	$ 29,774	992	0.5%	$ 30.00
Mead	Import	$ 4,298,743	251,688	3.6%	$ 17.08	$ 3,965,510	225,358	4.8%	$ 17.60	$ 333,233	26,330	1.1%	$ 12.66
Mead	Export	$ 1,908,730	27,680	0.7%	$ 68.96	$ 1,908,730	27,680	1.0%	$ 68.96	$ -		0.0%	$ -
N. Gila	Export	$ 31,509	1,050	0.1%	$ 30.00	$ 10,503	350	0.1%	$ 30.00	$ 21,006	700	0.2%	$ 30.00
NOB	Import	$ 5,874,963	502,436	3.7%	$ 11.69	$ 5,874,963	502,120	5.6%	$ 11.70	$ -	316	0.0%	$ -
NOB	Export	$ 23,334,535	617,638	11.7%	$ 37.78	$ 9,856,914	252,677	8.0%	$ 39.01	$ 13,477,621	364,961	19.2%	$ 36.93
Palo Verde	Import	$ 56,006,590	1,965,521	12.1%	$ 28.49	$ 37,118,230	1,141,045	10.2%	$ 32.53	$ 18,888,360	824,476	16.0%	$ 22.91

Table 7 (Continued)

Branch Group	Direction	All Hours				Peak				Off-Peak			
		Cost	Volume	Cong. Freq..	Avg. Price	Cost	Volume	Cong. Freq..	Avg. Price	Cost	Volume	Cong. Freq..	Avg. Price
Path 15	South-to-North	$ 167,483,229	4,409,586	37.1%	$ 37.98	$ 87,491,160	2,169,893	28.2%	$ 40.32	$ 79,992,069	2,239,693	55.1%	$ 35.72
Path 15	North-to-South	$ 3,108,065	95,825	3.2%	$ 32.43	$ 3,103,446	94,640	4.7%	$ 32.79	$ 4,620	1,185	0.2%	$ 3.90
Path 26	South-to-North	$ 220,239	39,256	0.6%	$ 5.61	$ 81,209	6,574	0.1%	$ 12.35	$ 139,030	32,681	1.6%	$ 4.25
Path 26	North-to-South	$ 93,437,714	2,193,203	11.0%	$ 42.60	$ 93,373,932	2,157,318	16.2%	$ 43.28	$ 63,782	35,885	0.7%	$ 1.78
Silver Peak	Import	$ 4,779	110	0.1%	$ 43.31	$ 4,779	110	0.2%	$ 43.31	$ -		0.0%	$ -
	Export	$ 5,192	187	0.1%	$ 27.71	$ 3,563	102	0.1%	$ 34.87	$ 1,629	85	0.2%	$ 19.13
Summit	Import	$ 80,105	2,866	0.3%	$ 27.95	$ 48,283	1,245	0.2%	$ 38.77	$ 31,822	1,620	0.5%	$ 19.64
Summit	Export	$ 294,166	4,602	0.7%	$ 63.92	$ 294,166	4,602	1.1%	$ 63.92	$ -		0.0%	$ -
Sylmar (AC)	Import	$ 704,775	3,754	0.6%	$ 187.75	$ 677,125	3,045	0.8%	$ 222.34	$ 27,650	708	0.3%	$ 39.04
Victorville	Export	$ 270,190	7,035	0.2%	$ 38.41	$ 270,190	7,035	0.3%	$ 38.41	$ -		0.0%	$ -