CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: July 24, 2000

Re: Market Analysis Report for June, 2000 and July 1-16, 2000

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

This report summarizes key market conditions, developments, and trends for June 2000. A special update of energy and ancillary markets conditions during the July 1-16 is also provided.

JUNE HIGHLIGHTS

- High loads combined with tight supplies across most of the Western U.S. led to record prices in both the energy and ancillary markets during June. Estimates of total energy and A/S costs for June were nearly $3.6 billion, or nearly $160/MWh of load served. The average unconstrained PX price for the month was $120/MWh while real time prices averaged roughly $127/MWh, up more than 400% from June 1999 levels. Unexpected warm weather meant substantially higher load growth in June 2000 over June 1999. Total energy was up nearly 13% while peak loads reach 43,447 MW, a 6% increase over June 1999. The warmer weather combined with two severe hot weather periods drove loads to exceed the 40,000 MW level during 51 hours (7%) in June.

- The high prices in the ancillary service markets were the result of substantially higher requirements, particularly in the replacement reserve market. The high replacement reserve requirements were the result of significant under-scheduling by both load and generation during many of the high load hours above 40,000 MW. Day ahead requirements for replacement reserves exceeded 10,000 MW for a number of hours.

- Natural gas spot and monthly natural gas prices were up nearly 100% relative to June 1999. Average daily spot prices for June for PG&E Citygate reached $4.73/MMBtu versus $2.46/MMBtu last June.

- Ancillary service costs jumped from $3.15/MWh of load served in May to about $20.19/MWh of load served in June 2000, representing an increase from about 6% of total wholesale energy costs in May to over 14% of total energy costs. Roughly 75% total A/S costs were incurred during six days: June 13-15 and 27-29 periods. More importantly, costs for replacement reserves were nearly half the month's total.

- Congestion on the major transmission paths continues to be very quiet with the exception of Path 15 and Path 26. A combination of tight regional supplies and high demand in the WSCC region led to higher prices in adjoining control areas, resulting in minor export congestion on the COI, NOB, Mead, and Summit branch groups. Overall congestion rates for Path 26 and Path 15 were 13% (N-S) and 38% (S-N), respectively.

KEY MARKET CONDITIONS FOR JUNE 2000

I. California Wholesale Energy Markets

- **Loads -** June 2000 had significantly warmer weather than June 1999. System energy loads totaled 21,568 GWh (29,956 average hourly MW), a 12.5% increase over June 1999 loads. Daily peak loads averaged 36,728 MW, 15% higher than average daily June 1999 peak loads. The peak load for the month was 43,447 MW for hour ending 16 on June 14 which represented a 6.2% increase over the June 1999 peak

- **Wholesale Energy Prices** – Energy prices in June were up sharply for both the real time and constrained PX markets compared to June 1999. The twelve-month percentage average price change for the real time market was up nearly 500% while constrained PX prices were up roughly 400%. Real time prices averaged roughly $125/Mwh while constrained PX prices averaged about $122/MWh. These prices represent more than a 100% increase over the price levels experienced in May 2000. Factors related to the price differences are:

  - Load growth over the last 12 months combined with the hot weather caused loads to exceed the 40,000 MW in 51 hours in June 2000 compared to six hours in June 1999 and 50 hours for July & August 1999 combined.

  - Load/resource balances throughout the entire Western region appear to be considerably tighter compared to last year. Hot weather and high loads in the Pacific Northwest during June coincided with many of the high load hours in California.

  - High real time prices were largely a result of the substantial under-scheduling of both load and generation in the day ahead market, particularly for hours when actual loads exceeded 40,000 MW. The difference between actual loads and hour ahead schedules averaged nearly 6,300 MW with incremental generation requirements averaging 5,300 MW for these hours.

  - Under-scheduling of significant loads and generation during days of tight regional energy supplies led the ISO to procure significant amounts of deviation replacement, with prices frequently hitting the $750 price cap when the supply of replacement offered was insufficient to met the entire shortfall between forecasted and scheduled. Since generation can be paid up to $750/MW in the replacement reserve capacity market and up to $750/MWh in the real time energy markets, the opportunity cost created by replacement reserve purchases and prices may have contributed to the “spiral” of higher prices in PX Day Ahead market experienced during June.

  - Significantly higher daily natural gas spot and monthly natural gas prices relative to June 1999. Monthly contract prices were up 86% while average daily natural gas spot prices were up 92% from a year ago. While these are substantial increases, natural gas prices can only explain roughly $30/MWh to $40/MWh of the total energy price increases experienced over the last 12 months.

- Prices in both the real time and zonal PX energy markets were higher in NP15 than SP15 for both the peak and off-peak periods. This is due to congestion patterns in both the day ahead and real time markets where there was substantially more south to north congestion on Path 15 than north to south congestion on Path 26. The PX day-ahead market had zonal price differences during 51% of the hours in June 2000 resulting in peak period constrained PX prices in NP15 being about 8% higher than SP15 prices. The real time market was split in 12% of the hours with peak period prices in NP15 also averaging about 8% higher than SP15 prices.

Table 1: Energy Price Summary for June 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$158.56	$ 161.59	$155.52	$154.62	8%
Off-Peak	$ 63.13	$ 71.46	$ 54.80	$ 54.80	19%
Total	$126.75	$131.55	$121.95	$121.34	12%
PX Constrained					
Peak	$155.67	$160.36	$154.12	$152.53	42%
Off-Peak	$ 47.02	$ 56.45	$ 42.31	$ 42.31	70%
Total	$119.45	$125.73	$116.85	$115.79	51%

- The ISO real time market experienced 34 hours where the $750/MW price cap was reached in either SP15 or NP15 and a total of 39 hours where prices were greater than $748/MW. Of these 39 prices, 34 occurred during hours with loads above 40,000 MW with incremental generation requirements averaging 5,500 MW. Constrained PX energy prices reached record levels as well, reaching a maximum of $1099.99/MWh in NP15 on June 28 for hours ending 14-18. The Path 15 congestion charges of $350/MWh for these hours will be discussed in the congestion summary section.

II. Ancillary Service Markets

Ancillary Service Prices

- The ISO continued to procure most of its A/S requirements in the day-ahead market, with between 81% to 92% of A/S MW quantities being procured in the day-ahead market. The following table summarizes weighted average prices and quantity procurements for June 2000 in both the day-ahead and hour-ahead markets.

	Day-Ahead Market (all hours)	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$168.70	$145.42	$166.63	645	63	91%
Regulation Down	$ 87.79	$ 49.52	$ 84.81	552	47	92%
Spin	$ 72.55	$ 53.58	$ 69.31	712	147	83%
Non-Spin	$ 72.47	$104.58	$ 76.73	860	132	87%
Replacement	$412.31	$383.02	$406.85	602	138	81%

- There were two periods during the month, June 13-15 and 27-29, where total ancillary service requirements were exceptionally high resulting in most of the month's price spikes for both the day ahead and hour ahead markets. In particular, very high replacement reserve requirements occurred during high load hours, generally above 40,000 MW, where there was significant under-scheduling of both loads and generation.

On average, the day ahead replacement reserve requirement for these hours was 5,250 MW, reaching a maximum value of 11,000 MW for HE 16 on June 15. There were 38 hours where total requirements for all A/S markets exceeded the total of all A/S capacity bid into the day ahead market (with the constraint of a maximum 50% purchase of imports for spin, non-spin, and replacement). In most of these hours, prices were at or near the price cap in the regulation up, spin, non-spin, and replacement markets.

- There were 42 price cap hits at the $750/MW level in the day ahead A/S markets. However, there were an additional 109 instances where the market clearing prices were above $748/MW but below $750/MW. The hour ahead A/S markets had 84 instances where the prices exceeded $748/MW with the $750/MW price cap being reached 51 times.

- The number of hours of zonal procurement of ancillary services in June was down compared to May, though there was higher congestion rates on Path 26/Path 15 combined in June compared to May. The price differentials between NP15 and SP15 for the spin, non-spin, and replacement markets are somewhat misleading given the very low number of hours with zonal procurement for those services. The differences between NP15/SP15 weighted prices are due to the weights being based on a supply perspective, i.e. relatively more requirements were procured from resources in zone SP15 on high load/high price days whereas relatively more requirements were purchased from resources in NP15 on low load/low price days. In the case of the regulation markets, the zonal price differentials are more indicative of zonal market conditions given the greater number of hours with zonal procurement. The following table compares weighted average A/S prices in the day-ahead market during peak and off-peak periods along with the percentage of hours during which ancillary services were procured zonally (day-ahead and hour-ahead combined).

Summary of Weighted Day-Ahead A/S Prices by Zone and Period – June 2000

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$148.75	$ 44.80	$329.13	$ 57398	21%
Regulation Down	$ 91.76	$ 55.58	$124.96	$ 56.97	12%
Spin	$ 79.50	$ 2.78	$151.82	$ 4.66	2%
Non-Spin	$ 55.49	$ 1.95	$136.88	$ 2.60	2%
Replacement	$322.40		$499.56		1%

Ancillary Service Costs

- A/S costs in June soared to $436.1 million compared to the May total of $63 million. June 2000 costs were 10 times the June 1999 level and were $30 million greater than total A/S costs for calendar year 1999. Roughly three-quarters of these costs occurred over just six days (June 13-15 & 27-29) and roughly half of the costs are attributable to replacement reserve purchases. The high costs are attributable to both the high prices and large MW requirements in both the day ahead and hour ahead markets, particularly for regulation up and replacement reserves. Total A/S costs for June were about 14.3% of total energy costs.

Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs**
March	$ .369	$ .60	2.0%
April	$ .576	$ .95	3.4%
May	$ 2.037	$ 3.16	6.1
June	**$14.533**	**$20.19**	**14.3%**

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)
** Energy cost = actual hourly loads multiplied by the PX Day-ahead Unconstrained MCP.

Cost Savings From A/S Redesign Changes

The extreme conditions in the A/S markets in June produced significant savings as per the separate pricing of RegUp/RegDown and the Rational Buyer protocols. The following table summarizes estimated savings from these A/S market redesign measures. These two measures have resulted in estimated savings of about $132 million since their implementation on August 17, 1999. This represents a saving of about 19% of total A/S costs during this time period. The very large savings realized in June were obviously a function of the increased A/S costs experienced during the month.

A/S Redesign Savings

	Rational Buyer		Separate Pricing of Reg Up/Down	
	Savings	Pct. of Total A/S Costs	Savings	Pct. of Total A/S Costs
August *	$6,000,000	20%	$3,893,000	14%
September	$1,285,000	4%	$5,936,000	19%
October	$2,048,000	4%	$7,643,000	17%
November	$ 678,000	3%	$6,612,000	31%
December	$ 589,000	5%	$3,056,000	29%
January	$1,317,000	11%	$2,571,000	22%
February	$ 295,000	3%	$1,239,000	12%
March	$ 685,000	6%	$1,465,000	13%
April	$ 854,000	5%	$4,242,000	24%
May	$7,166,000	11%	$8,123,000	13%
June	$33,559,000	8%	$32,466,000	7%
Total	$54,476,000	8%	$77,247,000	11%

* Savings after implementation on August 17, 1999.

III. Inter-zonal Congestion Management Markets

- The congestion markets in June experienced significant congestion on Path 15 and Path 26 with very low congestion rates on all other branch groups. The only congestion experienced on the Northwest paths (COI and NOB) was in the export direction. The following table summarized congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for June 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Export)	.4%	0%	.3%	$ .56		$ .56
Path 15 (S-N)	22%	69%	38%	$35.80	$20.45	$26.40
Path 26 (N-S)	20%	1%	13%	$ 8.00	$ .29	$ 7.92
NOB (Export)	2%	5%	3%	$15.05	$ 8.54	$11.02
Mead (Export)	5%		4%	$76.87		$76.87
Mead (Import)		1%	.3%		$36.88	$36.88
Sylmar-AC (Import)	3%		2%	$454.13		$454.13
Summit (Export)	1%		.7%	$110.87		$110.87
Summit (Import)		.3%	1%		$8.55	$8.55

- Path 15 congestion increased in June compared to May, rising from a 20% congestion rate to 38%. Roughly 40% of the congested hours occurred during peak hours. Day-ahead congestion charges on Path 15 ranged from $.02/MW to $350/MW and averaged $26.40/MW, an increase over the May average of $22.32/MW.

- Path 26 experienced congestion only in the N-S direction for June. The overall congestion rate decreased to 13%, compared to the 18% rate in May. Day-ahead congestion charges ranged from $.01/MW to $249.99/MW and averaged $7.92/MW, a decrease from April average of $20.48/MW.

- There was no day ahead import congestion on any of the northwest paths in June. Both COI and NOB experienced minimal export congestion rates of 0.3% and 3%, respectively. The export congestion was due to higher energy prices in the Northwest for many hours during the month, particularly in the early part of the month. In contrast, both COI and NOB experienced import congestion in June 1999 at rates of 15% and 8%, respectively.

- June congestion on the southwest paths also continued at very low levels in June. Palo Verde did not experience any congestion for the month, while Eldorado and Mead experienced day ahead congestion rates of 1% and 4%, respectively. Average congestion prices for Eldorado and Mead were $1.27/MW and $36.88/MW, respectively.

- Path 15 experienced day ahead congestion charges of $350/MW for HE 14-18 on June 28, which resulted in constrained PX zonal prices of $1,099.99/MWh in NP15. The unconstrained PX price for each of these hours was $749.99/MWh, which significantly limited the PX to use only those adjustment bids at the maximum price of $750/MWh, given that the PX can only use incremental bids that exceed the unconstrained price. The usage charges of $350/MWh were set via the adjustment bids of scheduling coordinators other than the PX.

- Total congestion costs for June were $18,421,000, an increase from the May 2000 costs of $5,290,000 and the $2,295,000 costs experienced in June 1999. Path 15 costs were $14,303,000 or 78% of the total, up substantially from the $459,000 costs in June 1999. Path 26 costs totaled $2,054,000 while Mead costs were about $950,000.

IV. Summary of Energy and Ancillary Service Market Conditions for July 1 – 16, 2000

The market results for the first two weeks of July were reflective of the mild weather conditions. Overall market conditions this month more closely resembled conditions experienced last May than either June 2000 or July 1999. Loads were substantially lower from June 2000 levels as well as levels experienced in July 1999. The peak load for the first half of the month was 37,942 MW, compared to the July 1999 peak of 45,574 MW and last month's peak of 43,447 MW. Average hourly energy for the month was 26,151 MW, compared to July 1999 levels of 28,878 MW and the June 2000 level of 29,956 MW.

Energy prices were substantially lower than June levels, and are comparable to June 1999 price level after adjusting for the doubling of gas prices from one year ago. Unconstrained PX prices averaged $56/MWh for the first 16 days of July compared to the June 2000 average of $120/MWh and the July 1999 average of $28.92/MWh. Real time prices are averaging $60.63/MWh for the month, down from last month's average of $126.75/MWh, but up substantially from the July 1999 average of $22.22/MWh. The highest real time price in July was $464/MWh, occurring at HE 17 on July 14, the peak load hour for the month thus far.

The ancillary service markets were also calm compared to June. The highest ancillary service price thus far in July has been $351/MW in the day ahead regulation down market. Prices have been very moderate with substantial reductions in the quantities procured as shown in the following table:

	Weighted Price	Weighted Price	Weighted Price	Average Hourly MW	Average Hourly MW
	Day Ahead	**Hour Ahead**	**DA+HA**	**Day Ahead**	**Hour Ahead**
Regulation Up	$33.84	$25.64	$33.33	320	21
Regulation	$37.89	$31.50	$37.63	292	12
Spinning	$ 7.22	$ 5.18	$ 6.92	393	64
NonSpinning	$ 5.02	$ 2.78	$ 4.76	464	58
Replacement	$ 1.61	$ .53	$ 1.43	112	21

Total ancillary service costs for July 2000 are roughly $22,341,000 which is about 3.7% of total energy costs and translates to $2.09/MWh of load served, compared to the June 2000 values of 14.3% and $20.19/MWh, respectively.

The congestion markets continue to be very quiet in the first half of July and remain essentially unchanged from the congestion patterns experienced over the last few months. The congestion rate experienced for Path 15 this month is 17%, with 80% of the congested hours occurring in the S-N direction. Path 26 has experienced a 12% congestion rate with all congestion in the S-N direction. The only other branch groups to experience any day ahead congestion was Cascade and NOB which had congestion rates of 1% and 2%, respectively. Total congestion costs were down substantially for the month, totaling $3.7 million compared to $10.2 million for the same period in July 1999.

V. Performance of the FTR Market in June 2000

FTR Concentration

The following table summarizes FTR ownership and control concentration as of the end of June 2000. This table shows high ownership concentration on several important interfaces. The table also shows that a relatively small percentage (41%) of the FTRs have been assigned Scheduling Coordinators.

The FTR ownership and control (scheduling) concentration on some paths is high enough to deserve close scrutiny of scheduling behavior to ensure FTR ownership/control is commensurate with scheduling needs. The DMA is also monitoring the scheduling activities of entities with FTRs in the directions inconsistent with the location of their resources within the ISO control area, or in amounts exceeding their historical scheduling needs.

FTR Concentration

Branch Group	CFE IMP	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	NOB IMP	PV IMP	P26 S-N	Silvpk IMP	VictVI IMP
FTR MW Auctioned	408	422	694	600	366	347	1,650	127	10	386
Max Single Ownership Concentration	47%	27%	59%	77%	64%	68%	37%	61%	90%	68%
FTR MW with SC Assignment	217	312	513	485	35	85	1,163	127	9	125
% FTR with SC Assignment	53%	74%	74%	81%	10%	24%	70%	100%	90%	32%
Max Single SC Concentration	25%	27%	59% (PX)	77% (PX)	7%	11%	36% (PX)	61%	90% (PX)	26%

Branch Group	CFE EXP	COI EXP	ELD EXP	IID-SCE EXP	MEAD EXP	NOB EXP	PV EXP	P26 N-S	Silvpk EXP	VictVI EXP	Total
FTR MW Auctioned	408	33	615	-	380	442	852	1,621	10	182	9,553
Max Single Ownership Concentration	43%	76%	49%	-	67%	43%	51%	62%	100%	50%	-
FTR MW with SC Assignment	150	8	50	-	25	100	100	328	10	116	3,958
% FTR with SC Assignment	37%	24%	8%	-	7%	23%	12%	20%	100%	64%	41%
Max Single SC Concentration	25%	24%	8%	-	7%	11%	6%	19%	100%	50%	-

FTR Scheduling

On most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached is indicated in the following table.

Branch Group	COI IMP	ELD IMP	IID-SCE	MEAD IMP	NOB IMP	PV IMP	Sil-Pk IMP	Total
MW FTR Auctioned	422	694	600	366	347	1,650	10	9,553
Avg. MW FTR Scheduled	12	391	446	6	12	596	9	1,472
% FTR Scheduled	3%	56%	74%	2%	3%	36%	90%	15%
Max MW FTR Scheduled	75	405	449	10	36	650	9	-
Max Single SC FTR Schedule	75	405	449	10	18	600	9	-

Secondary Market Activity

There were no secondary transactions during the month of June.

Adjustment Bid Markets

The following table summarizes the performance of the Adjustment Bid market based on simulation runs for the period June 1999 vs. June 2000. The manageable congestion range (MCR) indicates the amount of scheduled power flow on each interface that can be reduced through adjustment bids. When there is congestion on a interface a certain amount of scheduled flow needs to be curtailed. Adjustment Bid Sufficiency Index (ABSI) (expressed as %) is the ratio of MCR to the curtailed demand for transmission on the path. When ABSI is greater than 100%, usage charge is expected to be below price cap. Higher ABSI usually results in lower the usage charge because of higher available adjustment range relative to the amount of curtailment. The following table compares MCR and ABSI of 1999 and 2000. Congestion market performance is improving as indicated by higher ABSI in 2000 except Path 15. (Path 15 data is not strictly comparable between two years due to the creation of ZP26.)

Adjustment Bid Market Performance (June, 1999 vs. 2000)

Path /Direction		1999				2000			
		MCR (MW)		ABSI (%)		MCR (MW)		ABSI (%)	
		Avg.	Min	Avg.	Min	Avg.	Min	Avg.	Min
COI	Import	835	362	946%	402%	904	883	771%	666%
ELDORADO	Import	922	700	541%	232%	853	853	5029%	4754%
MEAD	Import	451	451	743%	743%	585	550	1331%	903%
NOB	Import	1352	1025	611%	95%	1726	1609	2396%	1845%
PALOVRDE	Import	-	-	-	-	-	-	-	-
PATH15	S-N	2887	2468	1100%	487%	2593	1527	334%	190%
PATH15	N-S	462	462	242%	242%	-	-	-	-
PATH26	S-N	-	-	-	-	-	-	-	-
PATH26	N-S	-	-	-	-	2538	1949	687%	348%

Explanation of Table Entries:

MCR = Manageable Congestion Range is the depth of the Adjustment Bid market (in MW) with economic adjustment bids on both sides of the path, taking into account market separation constraints.

ABSI(%) = Adjustment Bid Sufficiency Index (expressed as %) is the ratio of MCR to the curtailed demand for transmission on the path

Conclusions

The observation of the FTR and Adjustment Bid markets in June 2000 indicate the following:

1. More than 41% of the FTRs released in the primary auction have now been assigned Scheduling Coordinators.
2. The use of FTRs for their scheduling priority has been relatively small. Thus far FTRs have been used mostly to hedge against transmission price uncertainties.
3. FTR ownership and control concentration on some paths is quite high. These paths will be monitored closely for any unusual scheduling behavior during the high load periods.

VI. Issues Under Investigation

1. **ISO Price Cap Policy Options beyond November 15, 2000.** DMA is preparing a white paper that presents and evaluates several alternative approaches to mitigating overall market power once the ISO's current price cap authority expires on November 15, 2000. This draft paper will be sent to stakeholders for comment and suggestions on alternatives. A price cap policy is separate from local market power mitigation measures being developed as part of congestion reform. DMA will discuss long-term price cap options with stakeholders at the August MIF meeting and will present a final recommendation for Board vote at the September 6-7 Board meeting. A FERC filing is required prior to Sept 15, 2000.

2. **Interim Locational Market Power Mitigation (Interim LMPM).** DMA is developing an interim measure to mitigate the exercise of local market power by resources that must be dispatched in real time to meet locational needs. This interim measure is intended to remain in effect until the ISO addresses locational market power in a permanent fashion in the context of Congestion Management Reform. This approach is needed because there is currently no comprehensive measure in place to deal with locational market power. Even in areas with RMR contracts in place, an RMR outage causes the remaining units to bid excessively because they know their bids will face no competition.

   The interim approach is based on a clear distinction between market power and scarcity, and draws upon similar approaches that FERC has approved for other ISOs to mitigate locational market power. Locational market power is characterized by: (1) the absence of competitive supply to meet a locational need, where competitive supply entails three or more suppliers each offering at least 50 percent of the needed quantity of incremental or decremental energy, and (2) having to dispatch units out of BEEP merit order to meet the locational need. Such situations do not involve true scarcity since there is generally ample effective, available capacity to meet the need; the problem is that all the effective capacity is in the hands of only one or two suppliers.

   In these situations, when the resource's INC bid exceeds the market-clearing BEEP price (or when its DEC bid is below the MCP), the bid will be mitigated by substituting a resource-specific bid cap. The bid cap is based on the unit owner's choice of either (a) incremental operating cost plus fixed margin of x percent, or (b) a weighted average of recent MCPs earned by the resource when its bid was in merit order, adjusted for changes in system load and fuel prices. The resource would be paid the larger of its bid cap and the actual MCP, but would not set the MCP if its bid cap is above the MCP. The ISO is presently refining the initial proposal based on stakeholder and MSC input.

3. **Congestion Management Reform and Redesign.** The DMA is participating in the ISO's internal team to develop a Congestion Management Reform Proposal, with a view to creating a design that would incorporate effective economic incentives, and would be internally consistent and responsive to FERC's concerns and stakeholder inputs. The DMA is evaluating alternative design options for local market power mitigation measures.

   Three options under review: (1) Long-term contracting approach similar to current RMR with variable cost-based bids, (2) Creation of a new "local reliability market" with daily auctions subject to a price cap (based on the incremental investment cost of new resources) to limit locational market power, but allow the resource owner to be rewarded for providing a locationally necessary service, and (3) Integration of local reliability into the day-ahead congestion management process through bid caps on Adjustment Bids.

4. **Investigation of Market Events and Data Requests.** DMA is preparing a report for management and various outside agencies on market conditions, price spikes, and total market costs in late May and June. A

final report will be completed by August 1. DMA is responding to requests for operational and market data from a variety of outside agencies, including the Energy Oversight Board, California Public Utilities Commission, and FERC.

5. **Public Bid Data Release.** At the end of July 2000, the ISO will begin posting bid data, subject to a 6-month lag, on the ISO's web site. The effort to release this information was led by DMA in response to recommendations made from the MSC. On October 19, 1999, the ISO Board approved the release of the six-month lagged data with the possibility of a shorter lag if data sets were used in ISO or MSC reports. These special releases would be brought for Board approval on a case by case basis. Tariff language to support this policy was filed with FERC in January 2000 as part of the ISO's Amendment 25 – Q4 Tariff filing. FERC issued a ruling on Amendment 25 in March 2000 where they approved the release of the six-month lagged data but denied the release of bid data associated with ISO or MSC reports with as little as a one month lag, even if the release of these data were approved by the Board. (Publication of the six-month-lagged data is consistent with practices that FERC approved for the PJM and New York ISOs.)

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