Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: August 29, 2000

Re: Market Analysis Report

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

This report summarizes key market conditions, developments, and trends for July 2000.

JULY HIGHLIGHTS

- July experienced a two-week respite from the hot weather and high prices, before returning to higher loads and prices in the latter half of the month.
- The estimated total energy and A/S cost for July was about $2.55 billion, or nearly $118/MWh of load served, compared to about $3.6 billion, or $166 per MWh of load served in June. The main cause of lower costs in July was the imposition of the $500/MWh price cap ($100/MW for replacement capacity) on July 1, 2000.
- The average constrained PX price for the month was $91/MWh, down from the $120/MWh average in June, but up 265% from July 1999. Real time prices (SP15 & NP15) averaged $114/MWh.
- Daily peak loads averaged about 36,300 MW compared to about 35,100 MW in July 1999, representing an increased of about 3.4%. Loads exceed the 40,000 MW level during 33 hours, compared to 51 hours in June 2000 and 25 hours in July 1999.
- Prices remained high in the ancillary service markets, but were significantly moderated by the $100/MW price cap for Replacement Reserves and the $500/MW price cap for all other Ancillary Services.
- Ancillary service costs fell to $5.71/MWh of load served in July from about $20.19/MWh in June. Total A/S costs were about $125 million in July 2000, which is about 5% of total wholesale energy costs in July, compared to last month's 14% rate. Roughly 85% of A/S costs were incurred in the last half of the month.
- Daily natural gas spot prices continue to stay at levels roughly 87% higher than July 1999. Average daily spot prices for July for PG&E Citygate were $4.46/MMBtu versus $2.48/MMBtu last July. Daily spot prices for the Southern California Border averaged $4.65/MMBtu for July 2000 versus $2.40/MMBtu last year.
- Congestion on the major transmission paths continues to be low with the exception of Path 15 and Path 26. Most significantly, day ahead congestion in the export direction was experienced on COI, NOB, Mead, and Summit, though in minor amounts. As with June, higher prices in adjoining control areas led to the outflows. Overall congestion rates for Path 26 and Path 15 were 22% (N-S) and 20% (S-N), respectively.

KEY MARKET CONDITIONS FOR JULY 2000

I. California Wholesale Energy Markets

- **Loads –** Despite moderate weather during the first half of the month, system energy loads totaled 21,932 GWh for July 2000, the second highest monthly total since August 1998 which had energy use of 22,834 GWh. This represents a 2% increase over July 1999 and a 1% increase over June 2000. Daily peak loads averaged 36,300 MW, an increase of 3.4% over July 1999. The peak load for the month was 43,334 MW for hour ending 16 on July 24 which represented a 5% decrease from the July 1999 peak. There were 33 hours with loads above 40,000 MW compared to the June 2000 and July 1999 totals of 51 and 25, respectively.

- **Wholesale Energy Prices** – Energy prices moderated in July compared to the previous month, but were still up sharply for both the real time and constrained PX markets compared to July 1999. Real time prices averaged $114/Mwh while constrained PX prices averaged about $91/MWh. These prices represent a decrease from June 2000 of more about 10% in the real time market and a 24% decrease for constrained PX prices. Factors related to the price differences include:

  - Higher loads, as described in the previous section.

  - Load/resource balances throughout the entire Western region appear to be considerably tighter compared to last year. Pre-schedule prices for various trading points across the WSCC territory show higher peak period prices outside of California for a majority of days in July.

  - High real time prices continue to be the 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 5,900 MW with incremental generation requirements averaging 4,000 MW for these hours.

  - The reduction of the energy price cap to $500/MWh combined with the lowering of the replacement reserve price cap to $100/MWh significantly reduced deviation replacement costs for the month. However, continued under-scheduling of significant loads and generation during high load days led the ISO to procure significant amounts of deviation replacement reserve, which increased the effective price paid for real time energy.

  - Significantly higher daily natural gas spot and monthly natural gas prices relative to July 1999. Average daily natural gas spot prices are up nearly 90% 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.

- Peak period prices in both the real time and zonal PX energy markets were generally higher in SP15 than NP15, though off-peak prices were generally higher in the north. The price differential between zone for PX constrained prices is due to the predominance of N-S day ahead congestion on Path 26 during peak hours, while peak period congestion for the real time market was divided roughly equally in both directions. The higher real time prices in NP15 for the off-peak hours reflect the predominance of S-N congestion on Path 15. Energy prices by zone and period are listed in Table I.

- The ISO real time market experienced 38 hours where the $500/MW price cap was reached in either SP15 or NP15. Of these 38 hours, 35 occurred during hours with loads above 38,000 MW with incremental generation requirements averaging 4,100 MW. Constrained PX prices reached the $500/MWh price level eleven hours during the month.

Table 1: Energy Price Summary for July 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$138.41	$137.65	$139.17	$126.74	17%
Off-Peak	$ 65.60	$ 77.85	$ 53.34	$ 53.34	19%
Total	$114.14	$117.71	$110.56	$102.27	17%
PX Constrained					
Peak	$112.14	$102.32	$132.86	$101.24	50%
Off-Peak	$ 50.05	$ 53.59	$ 48.28	$ 48.28	35%
Total	$ 91.44	$ 86.08	$104.67	$ 83.58	45%

II. Ancillary Service Markets

Ancillary Service Prices

- The ISO procured most of its A/S requirements in the day-ahead market, with between 72% to 94% of A/S MW quantities being procured in the day-ahead market. Table 2 summarizes weighted average prices and quantity procurements for July 2000 in both the day-ahead and hour-ahead markets.

- The difference in load conditions between the first and last two weeks of the month is illustrated by the fact that 85% of the monthly A/S costs were incurred in the second half of the month. In contrast to June, replacement reserve requirements were significantly less, particularly for hours where loads were above 40,000 MW.

- There were 25 price cap hits at the $500/MW level for the day ahead and hour ahead markets combined, excluding the replacement reserve market which incurred 58 price cap hits at the $100/MW price cap for both markets.

- The number of hours of zonal procurement in the day ahead ancillary service markets in July was roughly comparable to June, with the exception of the regulation up market where the percentage of hours was down from 21% to 8%. Ancillary service prices were generally higher in SP15 largely due to the predominant N-S direction of congestion on Path 26. Table 3 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).

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – July 2000

	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	$91.80	$71.33	$90.57	629	40	94%
Regulation Down	$51.47	$36.61	$50.59	537	34	94%
Spin	$41.06	$25.99	$38.69	751	140	84%
Non-Spin	$16.98	$43.17	$20.61	879	141	86%
Replacement	$40.27	$65.59	$47.34	355	137	72%

Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – July 2000

	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$116.23	$ 33.87	$132.03	$ 38.69	8%
Regulation Down	$ 41.83	$ 56.17	$ 67.09	$ 51.30	13%
Spin	$ 35.93	$ 2.14	$ 93.16	$ 2.47	4%
Non-Spin	$ 16.12	$ 2.07	$ 32.08	$ 2.80	4%
Replacement	$ 33.27		$ 56.12		4%

Ancillary Service Costs

- A/S costs in July decreased to $125 million compared to the June total of $436 million due, in part, to the July 1 reduction of the capacity price cap from $750/MW to $500/MW ($100/MW for replacement reserves).

Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs
April	$ .576	$ .95	3.4%
May	$ 2.037	$ 3.16	6.1%
June	$14.533	$20.19	14.3%
July	**$ 4.041**	**$ 5.71**	**5.1%**

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

Cost Savings From A/S Redesign Changes

Conditions in the A/S markets in July, while not as extreme as in June, produced significant savings from 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 $166 million since their implementation on August 17, 1999, which represents a saving of about 20% of total A/S costs for this time period.

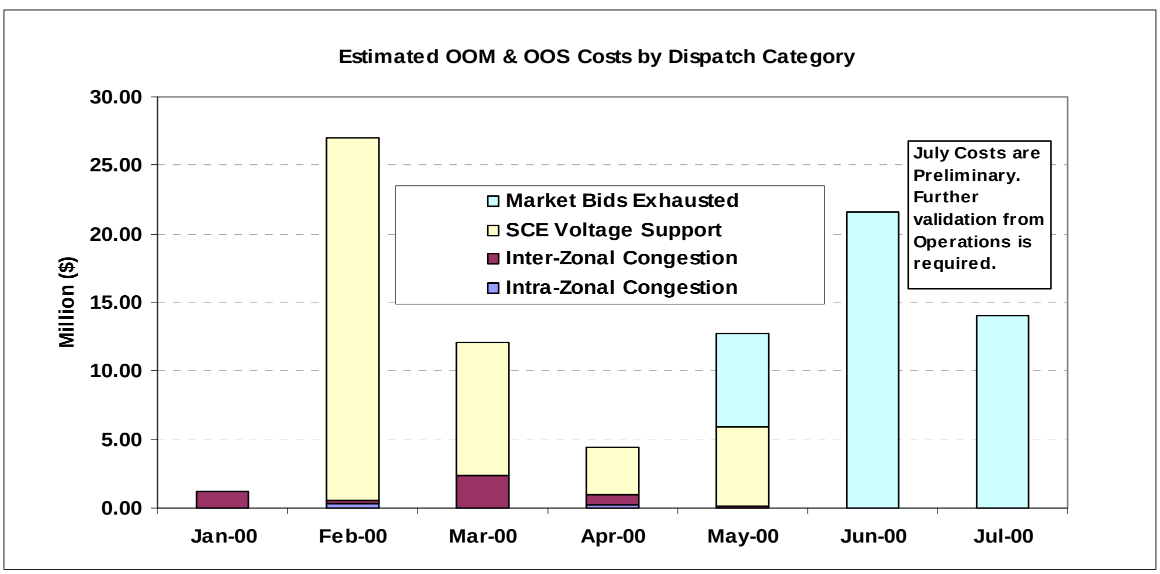
A/S Redesign Savings

	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%
July	$20,756,000	17%	$13,814,000	11%
Total	$75,232,000	9%	$91,061,000	11%

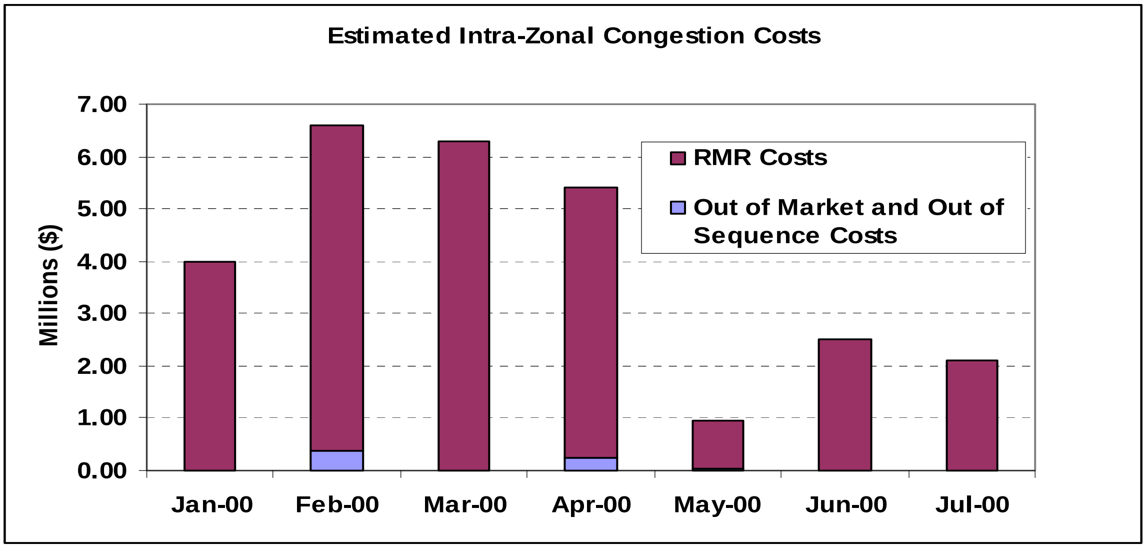
* Savings after implementation on August 17, 1999.

III. Out of Market and Out of Sequence Calls

The first chart shows an estimate of total monthly Out-Of-Market and Out-Of-Sequence costs by dispatch category. For June and July 2000, these costs totaled at approximately $22 million and $14 million, respectively, and were comprised entirely of OOM calls due to exhausting all available market bids. The estimated costs for July are preliminary. DMA is waiting for further validation from operations.



The next chart shows an estimate of total monthly intra-zonal congestion prices. These costs are comprised of both OOM and OOS costs and RMR costs. RMR costs are calculated net of energy market prices. For the months of June and July 2000, there were no OOM or OOS calls for intra-zonal congestion. Estimated RMR costs for these months were $2.5 million and $2.1 million, respectively. Lower RMR costs for May through July 2000 can be attributed to higher energy prices (i.e. more RMR units are in the market and if RMR units are called under their contract, the payment net of market revenues is lower).



IV. Inter-zonal Congestion Management Markets

The day ahead congestion markets in July experienced two major events: (1) significant congestion on Path 26, and (2) a significant number of branch groups that experienced modest or minor export congestion which was dissimilar to July congestion patterns in previous years. The following table summarized congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for July 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Export)	1%	0%	1%	$13.03		$13.03
Path 15 (S-N)	13%	34%	20%	$14.37	$15.49	$15.00
Path 26 (N-S)	33%	1%	22%	$96.22	$ 1.00	$95.64
NOB (Export)	3%	9%	5%	$13.39	$15.44	$14.68
NOB (Import)	15%	0%	10%	$14.79		$14.79
Path 15 (N-S)	4%	0%	2%	$18.59		$18.59
Mead (Export)	3%	0%	2%	$103.73		$103.73
Summit (Export)	6%	0%	4%	$30.00		$30.00
Eldorado (Import)	0%	2%	1%		$ 2.63	$ 2.63

- Path 26 experienced congestion only in the N-S direction for July. The overall congestion rate increased to 22%, compared to the 13% rate in June, with the significant majority of congested hours occurring during peak period hours. Day-ahead congestion charges ranged from $.02/MW to $398.66/MW and averaged $96/MW, a significant increase from the June average of $7.92/MW. Most importantly, total congestion costs on Path 26 totaled $36 million in July, representing the largest monthly total for any branch group for any month.

- Path 15 congestion decreased from the 38% congestion rate experienced in June to a rate of 23% in July. Roughly 90% of the congested hours occurred in the S-N direction. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $112.23/MW and averaged $15.43/MW, a decrease from the June average of $26.40/MW.

- There was no import congestion on COI in July while NOB experienced day ahead import congestion at a rate of 10%. This contrasts sharply to July 1999 import congestion rates of 51% and 18%, respectively. Both COI and NOB experienced minimal export congestion rates of 1% and 5%, respectively. The export congestion was due to energy prices in the Northwest being higher than California wholesale prices for many hours during the month. Nearly all of the export congestion on these branches was experienced between hours ending 1 to 9. The total net import day ahead schedules were more than 54% lower this month compared to July 1999.

- July import congestion on the southwest paths also continued at very low levels as Palo Verde and Eldorado both experienced congestion rates of less than 1%. The only other SW branch group to experience day ahead congestion was Mead, which had export congestion during 2% of the hours. Average congestion prices for Palo Verde, Eldorado, and Mead were $4.30/MW, $2.63/MW, and $103.73/MW, respectively.

- Total congestion costs for July were about $44 million, up substantially from the June 2000 total of $18.4 million and the $13.6 million total experienced in July 1999. Path 26 costs were $36 million or 82% of the total, Path 15 costs totaled $4.6 million, followed by NOB with costs of $2.4 million.

V. Summary of Market Conditions for August 1 – 22, 2000

The first three weeks of August experienced very high loads and prices across all of the ISO markets. The peak load through August 22 was 43,509 MW, compared to the August 1999 peak of 43,925 MW and last month's peak of 43,334 MW. However, the peak load adjusted for load shedding is estimated to be 45,208 MW. Average hourly energy for the month was 31,766 MW, a 9.5% increase over the August 1999 value of 29,016 MW and an 8% increase over July 2000 average energy. More importantly, average daily peak loads for August were 39,856 MW, a 12% increase over the August 1999 daily peak average of 35,647 MW and a 10% increase over the July 2000 average. There have been 60 hours with loads above 40,000 MW.

Average energy prices for August are the highest of any month since start up for both the PX and ISO energy markets, despite the reduction of the ISO price cap from $500/MWh to $250/MWh on August 7. Constrained PX energy prices (non-weighted) for the month averaged $141/MWh compared to the June & July 2000 values of $119/MWh and $91/MWh, respectively. ISO real time prices averaged $182/MWh for the month thus far, compared to June and July values of $127/MWh and $114/MWh, respectively. One of the significant aspects in the August energy markets is the significant increase in average off-peak real time prices to $100/MWh, compared to the July 2000 average of $65/MWh and the August 1999 average of $20/MWh. Total energy costs plus A/S costs are estimated to be $183 per MWh of load for August.

The real time market in August has experienced significantly more under-scheduling of both loads and resources in all hours, particularly in the off-peak relative to previous months. The combination of higher loads and imbalances in off-peak hours along with significantly higher export schedules in the off-peak have contributed to the higher real time prices in off-peak hours.

Energy Price Summary for August 1 - 22, 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$222.75	$231.96	$213.55	$213.41	27%
Off-Peak	$100.25	$123.44	$ 77.05	$ 77.05	47%
Total	$181.92	$195.79	$168.05	$167.96	33%
PX Constrained					
Peak	$178.39	$165.00	$205.61	$164.56	75%
Off-Peak	$ 67.48	$ 82.38	$ 60.04	$ 60.03	90%
Total	$141.42	$137.46	$157.09	$129.72	80%

Prices in the ancillary service markets were also extremely high for the first three weeks of August. A combination of high loads plus high requirements led to relatively low bid sufficiency levels in a number of markets resulting in average A/S prices exceeded only by June 2000 values.

	Weighted Price	Weighted Price	Weighted Price	Average Hourly MW	Average Hourly MW
	Day Ahead	**Hour Ahead**	**DA+HA**	**Day Ahead**	**Hour Ahead**
Regulation Up	$144.61	$140.39	$144.10	483	64
Regulation	$ 84.75	$ 64.14	$ 82.23	408	55
Spinning	$120.87	$ 47.47	$114.05	730	72
NonSpinning	$ 48.29	$ 98.46	$ 58.05	696	159
Replacement	$ 59.06	$ 78.63	$ 66.75	513	316

Total ancillary service costs for August 2000 are approximately $224 million, which is about 8% of total energy costs and translates to $13.36/MWh of load served, compared to the June 2000 values of 14% and $20.19/MWh, respectively.

The congestion markets show a much more pronounced export pattern than the previous two months. While COI did not experience any day ahead import congestion, export congestion occurred during 17% of the hours, primarily during the peak period. NOB experienced a 32% export congestion rate, with most congested hours during the off-peak period. Congestion rates on Path 26 and Path 15 were 38% and 39%, respectively, with Path 26 congestion in the N-S direction during peak hours and Path 15 congestion primarily in the S-N direction mostly during off-peak hours. Total congestion costs for August thus far have soared to $54 million (compared to $12 million in August 1999), with roughly 80% of these costs ($43.4 million) occurring on Path 26 and Path 15. Of the remaining $10 million of congestion charges, $8 million occurred as a result of export congestion. The surge in exports is largely the result of higher energy prices elsewhere in the WSCC region.

VI. Performance of the FTR Market in July 2000

FTR Concentration

The following table summarizes FTR ownership and control concentration as of the end of July 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	VictVl 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	262	513	485	35	85	1,163	127	9	125
% FTR with SC Assignment	53%	62%	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	VictVl 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	3,908
% 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	4	388	446	6	10	602	9	1,465
% FTR Scheduled	1%	56%	74%	2%	3%	36%	90%	15%
Max MW FTR Scheduled	100	405	449	10	18	650	9	-
Max Single SC FTR Schedule	100	405	449	10	18	600	9	-

Secondary Market Activity

There were no secondary transactions during the month of July.

Conclusions

The observation of the FTR and Adjustment Bid markets in July 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.

VII. Issues Under Investigation

1. **ISO Price Cap Policy beyond November 15, 2000.** DMA is investigating options to help formulate a price cap policy beyond November 15, 2000, when ISO's current authority to set price caps as provided by FERC's Orders of November 12, 1999 expires. The framework suggested by the DMA includes an interim price cap policy beyond November 15, 2000 until the on-going Comprehensive Market Redesign (CMR) elements are implemented, and sets the stage for a longer term policy on "price caps" and "bid caps" as part of the CMR process. Distinction is made between *price caps*, i.e., the maximum price buyers are willing to pay, and *bid caps*, i.e., maximum prices sellers are permitted to offer.

   A DMA white paper circulated for comments to the stakeholders sets forth an interpretation of FERC's rulings on price caps and bid caps, whereby price caps do not necessarily require FERC approval, whereas bid caps do. The white paper will be sent to the FERC (after stakeholder review) along with any filing to FERC to extend the ISO's price cap authority. Bid caps, and possibly availability standards will be included in the CMR as longer-term measures to identify and mitigate local and system-wide market power. The DMA will investigate alternatives for stakeholder and Board review, including the potential for thresholds triggering market power mitigation, and the corresponding level of bid caps. Options and criteria for the definition and enforcement of availability requirements would also be investigated and presented for review by the stakeholders and the Board.

2. **Investigation of Market Events and Data.** DMA prepared a report for management and various outside agencies on market conditions, price spikes, and total market costs in late May and June 2000. The report identified a number of factors responsible for price spikes in the ISO and PX markets, including the following:

   - High demand and tight supply in California and the regional markets:
     - High peak demand due to unseasonably hot weather
     - Generating units on maintenance based on expected normal seasonal conditions
     - Higher gas prices
     - Lack of new investment in generation and transmission
   - Lack of demand-side response
   - Market power, created by tight supply-demand conditions and the lack of demand elasticity.
   - Market Design and Operational Features
     - Under-scheduling of loads and generation
     - Replacement reserve procurement policy
     - Reliance on supplemental energy from other control areas

   The report also provided several recommendations that include enhancing demand response and hedging products, expediting generation and transmission investment, market power mitigation and availability requirements, and the reform of Replacement Reserve procurement policy.

3. **Market Design Option to Increase Forward Market Scheduling.** DMA is investigating a number of market design options for increasing forward market scheduling. One option under consideration would be to allocate the cost of forward OOM procurement to under-scheduled load rather than the current practice of spreading these costs to all load. Another potential market design option being investigated by DMA is how the incentive for suppliers not to schedule in the forward markets may be reduced by charging Deviation Replacement Reserve to un-scheduled generation only. A third market design issue related to under-scheduling involves the ISO's cap on adjustment bid prices, and whether this cap should be equal to the

ISO's real time price cap, or set at a higher level, such as the PX's new $350 price cap. Each of these market designs will be addressed in the DMA Director's Report at the September Board meeting.

4. **Special Investigations of Price Spikes and Market Power.** The DMA is collaborating with several other agencies undertaking investigations of market power and recent price spikes. These include FERC, the State Attorney General's office, the Public Utilities Commission (PUC) and the Energy Oversight Board (EOB).

5. **Comprehensive Market Redesign (CMR).** DMA's participation in the Congestion Management Reform project continues actively, and has been expanded as the need to address bid caps and availability standards and requirements has become an inseparable element of the project. To reflect its expanded scope, while keeping the same acronym (CMR), the project is now called Comprehensive Market Redesign.

6. **LARS Bid Evaluation.** The DMA is performing an analysis to support incorporation of local market power and market generation into the evaluation and selection of LARS bids.