Attachment S

THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	)	Docket No. EL00-95-045
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket No. EL00-98-042

AFFIDAVIT OF ANJALI SHEFFRIN REGARDING THE NEED FOR A 12-MONTH COMPETITIVENESS INDEX AS A MEASURE OF MARKET PERFORMANCE AND A PERFORMANCE- BASED INDICATOR FOR MARKET POWER MITIGATION

My name is Anjali Sheffrin. I am employed by the California Independent System Operator Corporation (ISO) as Director of Market Analysis. My business address is 151 Blue Ravine Road, Folsom, California 95630.

As Director of Market Analysis, I am responsible for developing and managing market monitoring activities for the ISO's electricity markets, ensuring an open and efficient market for energy, ancillary services, and transmission services. I am responsible for analyzing market performance, identifying market inefficiencies, and formulating recommendations for changes in market design. My duties include (1) analyzing market performance and identifying abuses of market power; (2) reviewing market rules and protocols for design flaws, gaming and market power opportunities; (3) recommending filings with the Federal Energy Regulatory Commission ("Commission") to change market rules for energy, ancillary services and congestion management markets in order to correct market design flaws or obtain authority to implement necessary mitigation measures; (4) reviewing the market impact of Reliability Must-Run (RMR) contracts; and (5) developing detailed performance indicators of market activity which are published as weekly and monthly market reports on the ISO Website.

I received a Ph.D. in Economics from the University of California, Davis in 1981. I have 22 years of managerial and technical experience in the electric utility industry working on utility deregulation, market design, competitive business strategies, generation, demand-side and transmission planning, load and market research, marginal cost of service studies, and rate design. Prior to joining the ISO, I was Manager of the Power Systems Planning and Evaluation Department at the Sacramento Municipal Utility District (SMUD). I directed a staff of 40 engineers, economists, and financial analysts in strategic planning and analysis. My responsibilities there included assessing generation options, initiating the relicensing of SMUD's hydroelectric project (Upper American River Project), transmission planning, load forecasting, and advanced and renewable technology development. I was the chief economist at SMUD through the closure of the Rancho Seco nuclear power plant and the evaluation of bids for replacement power. I started my professional career as Senior Economist in the

Load Forecasting Department of the Potomac Electric Power Company in Washington D.C. in 1980.

The purpose of my testimony is to support Commission approval of a new test that the Department of Market Analysis has developed to track the competitiveness of ISO energy markets. This new test is the12-month Competitiveness Index.[1] The 12-month Competitiveness Index compares, for a rolling 12-month period, actual market prices to an estimate of what prices would be if no firm had attempted to exercise market power. Specifically, the index is 1) the actual 12-month rolling total market cost calculated as the hourly market price multiplied by hourly demand and accumulated into 12-month totals[2] minus 2) the benchmark for market cost under competitive conditions, estimated as the hourly system marginal cost multiplied by the hourly system demand and accumulated into a 12-month total. Thus, the 12-month Competitiveness Index measures the extent to which prices remain above the competitive benchmark for a rolling 12-month period.

I recommend that the Commission adopt the 12-month Competitiveness Index as a test for determining when long-term market prices are uncompetitive and require intervention to reestablish just and reasonable rates. The ISO proposes

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[1] This index was first noted in comments of Anjali Sheffrin delivered at RTO Week, October 15-19, 2001, in Docket No. RM01-12-000, October 19, 2001 session on Market Monitoring.

[2] Scarcity hours are excluded from the calculation. When Demand *(1.10%) exceeds available supply, these hours are considered scarcity hours, and excluded from the calculation of price-cost markup.

that an effective standard for the index would be a $5/MWh markup. If on a 12-month basis, prices exceed competitive costs by a $5/MWh markup, the Commission would implement a prescribed set of mitigation measures. The mitigation measures would be pre-authorized by the Commission and would be enacted when the 12-month rolling average of price-cost markup exceeds the established threshold.

Triggering the index requires mitigation because under the Federal Power Act, the Commission must ensure just and reasonable rates. When the 12-month Competitiveness Index exceeds the threshold, the market will be deemed to be no longer competitive and, since the rates produced by an non-competitive market are unjust and unreasonable, action must be taken to uphold the standards set forth in the Federal Power Act. Because it might take months or years to implement a structural fix, regulatory mitigation must be implemented immediately and must remain in place until the market is restored to a competitive condition. The mitigation measures should be temporary, i.e., should stay in place until the market is found to be restored to a competitive condition. This should give the Commission and the ISO time to develop more permanent mitigation measures, if necessary.

The proposed 12-month Competitiveness Index is intended as an instrument to monitor electric market performance, and serve as an early warning device that market prices are not just and reasonable. It would provide a clear current signal that market mitigation measures are required. Importantly, it should be noted that the 12-month Competitiveness Index is not being proposed as a mechanism for calculating refunds or effectuating any retroactive changes to the market. Rather, the index will be calculated in a transparent manner using current market data so that all parties can monitor market performance and be aware of when conditions indicate that mitigation would be applied. Knowing in advance that market outcomes are nearing the point of mitigation allows all parties to self-police their actions so that the indicator's mitigation threshold will not be triggered. Thus, the 12-month Competitiveness Index should serve as a powerful self-regulating mechanism using the self-interest of market participants to regulate the market rather than relying on monitoring hourly market behavior. In other words, the 12-month Competitiveness Index allows normal demand and supply forces to equilibrate markets and calls for intervention only when the exercise of market power is shown to be significant on a sustained basis. Under these circumstances, the proposed index is consistent with the position enunciated in the Commission's "Working Paper on Standardized Transmission Service and Wholesale Electric Market Rate Design" that "[e]ffective ex ante mitigation is preferable to retroactive price changes."

The electric power market differs from other wholesale commodity markets. Electricity has many unique characteristics: it requires that supply and demand be balanced moment by moment; there are few practical ways to store electricity; electricity has few substitutes in the short term; there is little price responsive demand; and adding new supply requires several years. As a result, sellers of wholesale electricity are in a better position to affect prices than sellers of other commodities. These attributes of electricity, as well as the significant costs that uncompetitive action can impose in a short period of time, require that markets for electricity be managed differently than markets for other commodities.

An efficient, well-functioning market structure is the most effective means of mitigating market power in wholesale electricity markets. Some of the essential elements of a well-functioning market structure include significant price responsive demand, adequate capacity available to respond to high prices, an amount of load which is hedged and not exposed to short term price fluctuations, and retail rate structures which can adjust to wholesale price changes. Ensuring that these structural elements develop can take a long time, whereas the electricity market supply and demand balance can change in a moment from surplus conditions to tight conditions in which suppliers are pivotal in setting market prices. Therefore, until an efficient, functioning market structure is in place and an adequate market infrastructure is developed, regulatory safeguards such as the 12-month Competitiveness Index must be in place to curb the potential exercise of market power. The goals of a well-functioning, competitive marketplace and reduced regulatory intervention can best be achieved by adopting an effective regulatory safeguard such as the 12-month Competitiveness Index.

The goal of market monitoring and regulatory oversight is to ensure the just and reasonable rates required under the Federal Power Act. Competitive wholesale electricity markets can offer efficiency, increased choices, and savings to customers, if markets have the effective oversight that promotes competition. The 12-month Competitiveness Index would promote competition in that it uses the self-interest of all market participants to achieve a balanced market outcome. Suppliers would know when market outcomes are moving beyond an allowable threshold, and can self-regulate their bidding behavior accordingly. Load Serving Entities would know that the spot market continues to yield high prices, and that they should be hedged through forward contracting. State regulators would know that high prices would not continue indefinitely because there is a fixed threshold beyond which market mitigation would automatically occur and, as such, may not object to higher damage control bid caps and higher thresholds for bid mitigation. Federal regulators would have an objective standard to use to assess just and reasonable rates. Without this type of performance-based monitoring and mitigation, there will be more uncertainty, and parties will instead rely on the Commission's complaint process and lengthy regulatory proceedings to address, and mitigate, uncompetitive market outcomes – all after the fact. This could result in a slow response that would further damage the trust in the effectiveness of electricity markets already damaged due to the experience in California electricity markets from May 2000 to June 2001.

The proposed 12-month Competitiveness Index meets many of the objectives in the Commission's most recent working paper[3] on market power monitoring and mitigation. This paper provides a good definition of market power:

> Market power is the ability to raise market price above the competitive level. Market power can be exercised by withholding capacity or output from the market (physical withholding) or raising the price or offer (economic withholding). For a price to be above the competitive level, the price must reflect an excess over true scarcity value.

The Commission's paper also outlines what characterizes just and reasonable rates:

> Competitive prices reflecting no market power should be considered just and reasonable. The Commission should intervene in markets, beyond standard preventive measures, when market power is significant and sustained. Further mitigation should be used only when it is clear that short-term supply and demand forces cannot prevent significant and sustained market power....
>
> Significant market power involves prices some significant degree above competitive levels. Sustained market power includes circumstances which cannot be remedied by short-term supply, demand, or market rules. Probably it should be measured in months rather than hours or years. Sustained market power includes recurring market power that may appear and disappear with cyclical demand variation. Investment and entry of generation or transmission, given significant construction and siting timelines, typically takes too long to prevent significant and sustained exercises of market power. The Commission may wish to develop more specific standards of significant and sustained market power. For example, the Commission may wish to adopt a standard that balances the tradeoff between the magnitude and the length of time of the price increase.

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[3] Strawman Discussion Paper For Market Power Monitoring and Mitigation Panel, Technical Conference on Market Structure and Design, Docket No. RM01-12, February 7, 2002

The proposed 12-month Competitiveness Index addresses all of the considerations discussed above. It measures sustained and significant deviations of market prices above competitive levels, balances the magnitude of the price increase with the length of the time the increased price was charged, and considers scarcity value. The proposed index will be a transparent, feasible and effective measure of just and reasonable rates.

The determination of the appropriate threshold for this index is important. In earlier rulings, the Commission adopted as a threshold a 10 to 15% deviation of prices above competitive levels.[4] The ISO instead suggests that the threshold be based on the fixed amount of $5/MWh. This threshold was selected to allow for a sufficient return on investment for new generation resources. The ISO examined the past four years of market performance data in recommending this threshold. From April 1998-March 1999, the price-cost markup averaged $-0.84, from April 1999-March 2000, the price-cost markup averaged $2.29, from April 2000-March 2001 the price-cost markup averaged $47.15, and from April 2001-March 2002, the markup is estimated at $54. This analysis shows that the market achieved close to competitive levels in the first two years of operation. The markup level during these two years did not discourage new investment, since there were numerous permits filed to site new generation with the California Energy Commission in the years 1998 and 1999.

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[4] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Docket No. RM95-6-000, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, Docket No. RM96-7-000, slip op. at 25-26 (Jan. 31, 1996).

Capacity of Energy Commission Certification Permits Filed 1997 to 2001

Year AFC Filed	*Capacity Planned*	*Capacity Withdrawn*	*Net Capacity Planned*
1997-98	4328 MW	0	4328 MW
1999	4940	0	4940
2000	5740	1334	4406
2001	12779.4	3473	9306.4

Note: CEC is required to certify thermal generators over 50MW. Smaller confidential thermal generators and other types of generation are not included

Source: California Energy Commission website, Thermal Power Plant Projects
Before the California Energy Commission 1976-2002. Last updated February 22, 2002.
http://www.energy.ca.gov/sitingcases/projects_since_1976.html

In 2000 and 2001, the markup above marginal cost averaged $50/MWh, which clearly shows that market power was exercised with resulting prices above competitive levels on a significant and sustained basis. As the ISO has noted in previous filings, this price level allowed the *full* cost of a new peaker unit to be recovered within two years.[5] Clearly this was excessive and exceeded all previous standards for capital recovery.

Concern has been expressed that marginal cost pricing will not allow sufficient recovery of capital investment for power plants. These concerns are not founded in fact. First, competitive market prices provide sufficient cash flow for most generation owners to recover their investment. Market clearing prices are set by the most expensive resources needed to meet demand. Most generation

[5] Eric Hildebrandt, "Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market," filed as Attachment B to "Comments of the California ISO on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market," in Docket No. EL00-95-012

resources have lower costs than the marginal units being dispatched and, therefore, earn a return on investment during many hours of the year. Units with the highest heat rates are under RMR contracts or can be compensated under the new Available Capacity Requirement (ACAP). Therefore, the threshold should allow the most expensive units to earn a sufficient return, while allowing the remaining units to earn an above-average return -- which in all likelihood will be more than the return the unit would earn under traditional cost-of-service rate making. Revenues from ancillary service payments, RMR payments and Available Capacity Requirement (ACAP) payments are all revenue sources available for generation owners. This will enable generators to receive payments sufficient to cover fixed costs and a return on their investment, thereby making the total return allowed under the $5/MWh threshold generous. Considering all the factors mentioned above, this should allow adequate return for generation owners.

In estimating the competitive market price, the ISO considered all available in-state resources and the amount of imports. For most fossil fuel generation resources, the available capacity is the maximum capacity minus planned maintenance, historical forced outages and deratings. The unit's marginal cost is determined by its incremental heat rate times the daily spot market prices of corresponding fuel. For some hydroelectric and energy limited generating resources which are not owned by net buyers, the ISO will estimate their opportunity cost based on expected market price and the energy limits. Many different authors have calculated estimates of competitive benchmark prices using different data sources and different assumptions.[6] These studies show similar findings of price-cost markup and demonstrate how robust this calculation can be. Additionally, the price-cost markup has been calculated for different ISOs in the United States allowing for comparison of market performance under different market designs and different market conditions.

To best reflect the current market conditions, a weighted average of spot market and real time market energy quantity and prices would be considered in calculating actual market costs. The most reliable data would include a weighted average of day-ahead, hour-ahead, and real-time market transactions. Currently, since there is no formal Day Ahead market, the index is being calculated using data for 2001 and first months of 2002 on the ISO real time market and CERS Day Ahead and Hour Ahead bilateral purchases. Since there is a 47-day delay in receiving pricing information for Day Ahead and Hour Ahead purchases from CERS, the ISO would use the Dow Jones prices for day ahead prices as published in the Electricity Price Index on the Dow Jones newswire, and the actual purchase quantities in the day ahead and hour ahead. When ISO starts to

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[6] Frank Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," *POWER Working Paper PWP-086,* University of California Energy Institute, revised December 2001; Paul L. Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," *National Bureau of Economic Research Working Paper #8157,* March 2001; Erin Mansour, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electric Markets," *POWER Working Paper PWP-083,* University of California Energy Institute; and James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," February 2002, http://www.iso-ne.com/iso_news/

operate a Day Ahead energy market, the Day Ahead market costs will be part of the input.

The purpose of the 12-month Competitiveness Index is different than the purpose of damage control bid caps. Bid caps are in effect regardless of overall competitiveness of the market. Bid caps provide a constant safety net to guard against occasional large price spikes. The 12-month Competitiveness Index and accompanying mitigation measures provide protection against sustained market power. However, mitigation measures would not be invoked through the 12-month Competitiveness Index due to infrequent price spikes if the overall market is competitive. If unexpected conditions result in a sustained exercise of market power with significant adverse impact on consumers, the measures would be enacted to ensure just and reasonable rates in market outcomes.

Another proposed mitigation measure is the Automated Mitigation Procedure (AMP), which checks bid prices against historical bidding and mitigates bid prices if they deviate significantly from the norm. AMP is another tool to curb gross market power on an hourly basis. It limits the strategic bidding used to exercise market power. The threshold used there is relatively high, i.e., 100% or $50/MWh. Even if the bids are all within the threshold, there is no guarantee of a competitive market outcome, as demonstrated in California in August 2000 to November 2000 when bids hit the price cap for many peak and off-peak hours. This can result in as much as a 100% markup in terms of 12-month price-cost markup. The 12-month Competitiveness Index and automatic mitigation is still necessary to ensure just and reasonable rates.

Concern has been expressed that the costs of market power to consumers could be in the billions of dollars if the 12-month Competitiveness Index is used. The ISO has estimated the cost exposure of a $5/MWh mark-up to be approximately $152 million per year, well below one billion dollars.[7] This cost exposure is estimated using the full net short position (the Demand an Investor Owned Utility must serve less the utility's retained generation) minus the long-term contracts and quarterly purchases. The calculation assumes that the full amount of short-term purchases (one month in advance purchases, balance of monthly, weekly, daily and real-time) could be subject to market power demonstrated in spot markets for electricity.

The following chart illustrates the12-month Competitiveness Index using a $5/MWh threshold applied to the California market since ISO start-up. Monthly price-cost markups are shown along with a cumulative 12-month average of these markups. The 12-month Competitiveness Index remained below $5/MWh

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[7] Estimated annual cost of the $5/MWh band:

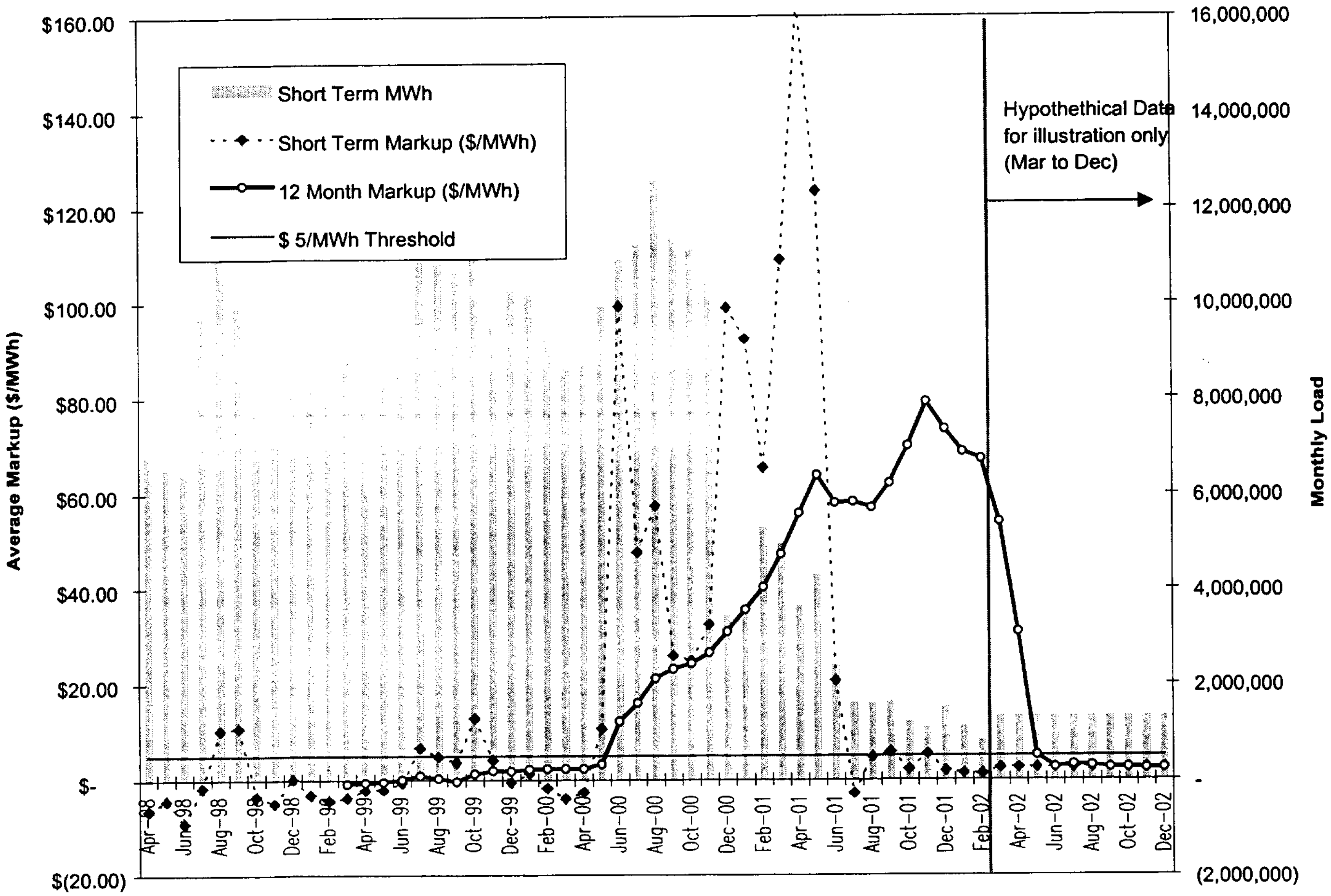
Average monthly net short: 4733 GWh
Average covered by Long Term Contracts and Quarterly Purchases: 2200 GWh

Difference = 2533 GWh

Total Cost = 2533GWh *1000MWh/GWh*$5/MWh*12months = $152 million/yr.

in the first two years of ISO market operation despite occasional high monthly price-cost markups. The 12-month Competitiveness Index moved-up to above \$5/MWh in May 2000 after significant price spikes at \$750/MWh. As shown below, such an index would have alerted all parties (consumers, regulators, suppliers) that markets had become uncompetitive in early summer 2000. Higher price spikes after June 2000 pushed the index to \$20/MWh and above, clearly showing an uncompetitive market. If the 12-month Competitiveness Index had been in place at the time, most of the disaster of 2000 and 2001 could have been avoided.

Evaluating California Market Performance Using 12-month rolling index With a $5/MWh Threshold



Although volumes in the spot markets moderated as long-term contracting increased, the markup continued to be high and, in fact, was highest in April and May 2001. This continued to drive the 12-month Competitiveness Index higher. Market performance improved in July 2001 when west-wide price caps, the must-offer obligation, and significant conservation by consumers caused suppliers to be less pivotal in setting prices. Although the 12-month Competitiveness Index continued to rise, better monthly market performance would cause it to go down after markets had sufficiently stabilized. I expect the index to revert back to competitive levels by June 2002 if market performance continues to be stable as demonstrated in the recent months. A full 12-month view is important because electricity demand is very seasonal, and it takes a 12-month window to review market performance under all conditions.

In summary, application of the 12-month Competitiveness Index demonstrates that it reflects when markets were competitive, and also reflects the dramatic changes that occurred in the market since 2000 and when the market will be sufficiently stabilized. Thus it can serve as the early detection system necessary to effectively monitor, promote competition in and ensure just and reasonable rates in electricity markets.

County of Sacramento
State of California

By: Anjali Sheffrin

Print Name: Anjali Sheffrin

Subscribed and sworn before me on this 29th day of April, 2002

Phat Myers

Notary Public

My Commission Expires: July 20, 2004

PHAT MYERS
Commission #1271220
Notary Public - California
Sacramento County
My Comm. Expires Jul 20, 2004

Attachment T

CONSISTENCY BETWEEN THE FEDERAL ENERGY REGULATORY COMMISSION'S STANDARDIZED MARKET DESIGN AND THE CALIFORNIA ISO'S MD02 COMPREHENSIVE MARKET DESIGN

ELEMENTS OF FERC'S STANDARDIZED MARKET DESIGN WORKING PAPER	CALIFORNIA ISO MD02 COMPREHENSIVE MARKET DESIGN	
	Consistent with FERC's SMD working paper	Comments
New Transmission Service		
Network Access Service	**Yes**	The ISO has offered a flexible form of network service for the last four years that is equal to the Network Access Service. ISO Tariff Section 2.2.
Transmission Rights		
"Source-to-Sink"	**Yes**	FTRs will be point-to-point. MD02 Filing, Section 5.3.2.1.
Flowgate (If Requested)	**Yes**	The ISO is assessing the need for flowgate FTRs. MD02 filing, Section 5.3.2.1.
Obligations/Options	**Yes**	FTRs will be obligations. MD02 Filing, Section 5.3.2.1.
Physical Rights Expire after DA	**Yes**	FTR holders would have a scheduling priority only in DA market. MD02 filing, Section 5.3.2.1.
Financial/Revenue Stream	**Yes**	FTR holder collects congestion revenues when it does not schedule transmission service. MD02 filing, Section 5.7.2.1.
Simultaneous Feasibility for FTR Auction	**Yes**	The ISO will run a simultaneous feasibility assessment to determine the amount of FTRs that can be released in auction process. MD02 Filing, Section 5.3.2.1.
FTR Secondary Market	**Yes**	Under Section 9.8.1 of the ISO's Tariff, FTRs may be assigned, sold or transferred.

Congestion Management		
Locational Marginal Pricing	**Yes**	Full network model with locational marginal prices at each node in the grid. MD02 Filing, Sections 5.2.2.1 and 5.6.2.1.
Voluntary Bid-based, Security Constrained Market	**Yes**	In forward market, SCs can submit Energy/Adjustment Bids on their preferred generation and load schedules that will be used to clear congestion. Final schedules will be feasible with respect to all transmission constraints as well as generator ramping and other performance constraints. ISO will use optimal power flow security constrained unit commitment (SCUC) algorithm. In HA, congestion will be resolved using TCUC. MD02 Filing, Sections 5.2.2.1 & 5.6.2.1.
Simultaneous TX/Energy/AS	**Yes**	Market Separation Rule eliminated. ISO will use simultaneous, integrated approach for energy, congestion management and ancillary services. MD02 Filing, Sections 5.2.2.1, 5.4.3 and 5.6.2.1.
ENERGY MARKETS		
Day-Ahead		

Voluntary Bid-based, Security Constrained Market	**Yes**	SC's can submit Energy/Adjustment Bids on their preferred generation and load schedules. The proposal ensures that final schedules are feasible with respect to all constraints, as well as generator ramping and other performance constraints. ISO will use optimal power flow security constrained unit commitment (SCUC) algorithm. MD02 Filing, Section 5.2.2.1.
Voluntary Participation/Accomodates Bilateral Transactions and Self-supply	**Yes**	The ISO will permit SC's to schedule bilateral transactions or self supply rather than bid into DA market. MD02 Filing, Sections 5.2.1, 5.2.3.2 and 5.2.2.1.
Demand Participation	**Yes**	The ISO's proposal permits demand side bidding, including the option to submit multi-part bids. MD02 Filing, Section 5.8.2.2.
Multi-part Bidding	**Yes**	DA Unit Commitment Service allows 3-part bids. Resources can submit multi-part bids as can Demand. MD02 Filing, Sections 2.5, 5.5.2 and 5.8.2.2.
Voluntary Balanced Schedules	**Yes**	The balanced schedule requirement is being eliminated. MD02 Filing, Section 5.2.1.
Nodal Pricing	**Yes**	The forward energy market will produce locational marginal energy prices at the nodal level. MD02 Filing, Sections 5.2.1 and 5.2.2.1.

Clearing Price Auction	**Yes**	The DA market will clear all economic demand and supply bids. MD02 Filing, Sections 5.2.1 and 5.2.2.1.
Voluntary Trading Hubs	**Yes**	Under the Full Network Model, the ISO will create various aggregations of nodes for the purposes of simplifying load scheduling and settlement and serving as trading hubs. MD02 Filing, Sections 5.2.2.1 & 5.2.2.3.
Uplift Payments for Generators torRecover sStart-up and Minimum Load Costs Not Recovered through Market Participation	**Yes**	For UCS and RUC, where start-up and minimum load costs exceed market revenues earned through real-time dispatch, such excess amount will be recovered via an uplift charge. MD02 Filing, Sections 5.5.2 and 2.5.
Intermittent Resources	**Yes**	Intermittent resources are permitted to participate in DA market. MD02 Filing, Section 5.2.5.
Real Time		
Bid Based, Security Constrained Market	**Yes**	Real time imbalance energy dispatch will be accomplished using a Security Constrained Economic Dispatch (SCED). SCED will be based on energy bids submitted by participating resources, subject to transmission interface, nomogram and resource capability constraints. MD02 Filing, Sections 5.6.2.2, 5.6.2 and 5.7.2.1.

Single Part Bid (Energy)	**Yes**	Participating resources submit Energy bids. MD02 Filing, Sections 5.6.2.2. and 5.7.2.1.
Nodal Pricing	**Yes**	SCED will produce nodal and hub energy prices. MD02 Filing, Sections 5.6.2.4 and 5.7.2.1.
Clearing Price Auction	**Yes**	Absent RT transmission constraints, imbalance energy will be economically dispatched based on a submitted energy curve. MD02 Filing, Sections 5.6.2.4 and 5.7.2.1.
Real-Time Settlement for Imbalances	**Yes**	Imbalances will be settled at the RT price. MD02 Filing, Sections 5.6.4 and 5.7.5.
Demand Bidding Accommodated	**Yes**	Demand resources are permitted to submit bids to increase or reduce energy consumption. MD02 Filing, Section 5.6.2.2.
Penalties for Uninstructed Deviations	**Yes**	The ISO is proposing penalties for uninstructed deviations outside the greater of 5MW or a three-percent bandwidth. MD02 Filing, Sections 5.7.4 and 5.13.2.
Ancillary Services Markets		
Suppliers Must Meet Specific Operational Requirements	**Yes**	Resources supplying AS must be certified for the specific AS to be offered. MD02 Filing, Section 7.2.6.
Opportunity for Demand to Supply Operating Reserves	**Yes**	Demand bidding is accommodated. MD02 Filing, Section 5.4.4.

Bid-based DA and RT Market to Procure Regulation and Operating Reserves	**Yes**	The ISO will operate a bid-based DA and RT market. AS will be procured simultaneously with Energy. MD02 Filing, Section 5.4.2.
LSE Satisfaction of Obligations through Self Supply/Bilateral Transactions	**Yes**	LSE AS obligations can be satisfied by self-supply/bilateral transactions. MD02 Filing, Section 5.4.4.
AS Procured Through Bid-based Auction	**Yes**	AS resources will be selected using an opportunity cost approach based on a resource's Energy bid. MD02 Filing, Section 2.5.
Availability Bids Permitted	**Yes**	The ISO will allow suppliers to submit capacity bids for AS, in addition to Energy bid curves. MD02 Filing, Section 2.5
DA AS Market Clears Simultaneously with DA Market for Transmission and Energy	**Yes**	The ISO will utilize a simultaneous optimization approach to do Energy, congestion management, AS procurement and unit commitment in an integrated run of the DA markets. MD02 Filing, Section 5.4.1.
Rational Procurement/Least Cost	**Yes**	Procuring AS simultaneously with the Energy market will result in a more efficient and rational price structure for both. AS prices will not exceed Energy prices. MD02 Filing, Section 5.4.2.
Bid Limits to Account for a Limited Number of AS Supplies	**Yes**	The ISO's proposed bid mitigation would apply to AS.
Substitution	**Yes**	High-quality services can substitute for lower quality services. MD02 Filing, Section 5.4.2.
Market Power Monitoring And Mitigation		

Structural Solutions in Addition to Bid Mitigation	**Yes**	The ACAP proposal, in conjunction with the RUC process, will help ensure that sufficient capacity is available in the DA market. MD02 Filing, Sections 5.1 and 5.5. The ISO's Participating Load Program meets most of the principles outlined in the SMD paper, and the ISO is making other accommodations to enhance Demand response. MD02 Filing, Sections 5.8.2.2 and 5.8.3.
Bid Cap as a Proxy for Demand Bidding	**Yes**	The ISO proposes continuation of the West-wide mitigation. In the MD02 Filing, the ISO is proposing a Damage Control Bid Cap. MD02 Filing, Section 5.10.2. The ISO also is proposing resource bid screens and mitigation (i.e. AMP procedures). MD02 Filing, Section 5.10.2.
Locational Market Power Mitigation	**Yes**	The ISO is proposing unit-specific bid caps to address local market power concerns. MD02 Filing, Section 5.9.2.
Limits on Flexibility to Change Bids	**Yes**	Once submitted, Energy bids cannot be increased. MD02 Filing, Section 5.6.2.2. Once selected, Energy bids associated with the selected AS capacity would not be allowed to be modified. MD02 Filing, Section 2.5.

Coordination of Maintenance and Outage Schedules	**Yes**	Sections 2.3.3 and 5.5 of the ISO's tariff and the ISO's outage protocol provide for coordination and monitoring of maintenance and outage schedules.
MMU Independent from Management	**No**	The ISO believes that a MMU can effectively operate while reporting to ISO management. The ISO is willing to identify and consider necessary clarifications to DMA's reporting relationship with ISO management to ensure that DMA has unfettered access to FERC and the ISO Board.
MMU Monitors All Markets in the Region	**Yes**	The DMA will continue to monitor all markets in the ISO control area under the MD02 Filing.
Long-Term Generation Adequacy		
Measures to Ensure Long-Term Generation Adequacy	**Yes**	The proposed ACAP requirement will ensure that LSEs procure sufficient capacity to meet forecasted load and an applicable reserve margin. MD02 Filing, Section 5.1.
State/Regional Authority to Set Reserve Margin	**Yes**	The ACAP proposal is based on WECC MORC translated into a monthly obligation. MD02 Filing, Section 5.1.3.
Selective Curtailment	**Yes**	Under ACAP, deficient LSEs will be asked to curtail an identifiable amount of load. MD02 Filing, Section 5.1.11.

State Participation in RTO Activities		
Advisory Committee	**The MD02 Filing is not intended to address this issue**	The ISO believes that a high level of coordination is required between state and federal policy makers and states have a legitimate interest in RTO operations. This can occur through an advisory committee or some other mechanism.
Other OATT charges		
Independent ATC Calculation	**Yes**	The ISO already posts & calculates ATC and OTC.
CBM Transmission Rights	**This issue is not addressed in the MD02 Filing**	The ISO has not yet developed a cost allocation proposal for CBMs.

Attachment U

Board of Governors **Comprehensive Market Design**

Moved, that the Board:

1) **Approves Management's recommendations for a hypothetical Comprehensive Market Design that moves the California markets to model FERC's proposed Standard Market Design (SMD), and that provides greater price transparency for users of the California grid, and that provides for greater reliability in the ISO's operation of the electric transmission system subject to reconsideration of the entire design when California's Electricity markets are returned to a stable condition. The elements of the design include the following elements as described in the Board memorandum, dated April 19, 2002, and the design document attached to the memorandum:**

   a) **Firm Transmission Rights (FTR)**

   b) **Day Ahead Congestion Management**

   c) **Forward Spot Energy Market**

   d) **Ancillary Services Market**

   e) **Residual Unit Commitment**

   f) **Real-time Economic Dispatch Using Full Network Model (LMP), subject to reevaluation upon receipt of sufficient data**

   g) **Bid Mitigation for Local Reliability Needs**

   h) **Penalties for Excessive Uninstructed Deviations**

And,

2) **Approves Management's recommendation for a hypothetical Available Capacity Obligation (ACAP), as an integral part of the Comprehensive Market Design that places the requirement on Load Serving Entities (LSE) to make available sufficient capacity to the ISO so that expected energy demand can be met subject to reconsideration of the entire design when California's Electricity markets are returned to a stable condition**

with the caveat that the AFEC proposal be fully evaluated for incorporation into any ACAP design and that any ACAP give full credit to any contracts endorsed by CERS.

And,

3) Directs Management to prepare and file the items listed above with FERC on May 1, 2002, with tariff language to follow.

Moved: Geesman Second: Florio

Board Action: **Passed** Vote Count: **5-0-0**	
Finney	Y
Florio	Y
Geesman	Y
Guardino	Y
Kahn	Y

Moved, that the Board:

1) Approves Management's recommendation as amended below to file at FERC, for approval, a "less preferred" alternative interim market power mitigation proposal, to be effective and implemented by October 1, 2002, in the event that the FERC does not extend the "preferred" interim measures, as established in the June 19, 2001 FERC order, that are scheduled for expiration September 30, 2002. The subset of measures include the following elements as described in the Board memorandum dated April 19, 2002 on this subject:

   a) Bid Screen Mitigation (AMP);

   b) Damage Control Bid Cap, set as a "hard cap" at $108 indexed to gas as reflected in the current west-wide mitigation

And,

2) Approves Management's recommendation to file at FERC, for approval, an additional subset of the Comprehensive Market Design proposal, comprised of certain operational, market power mitigation, and other supporting measures, to become effective and implemented by October 1, 2002 to support continued reliable operation of the California transmission grid and stable markets. These elements include the following elements as described in the Board memorandum dated April 19, 2002 on this subject:

   Operational Elements:

   a) Residual Unit Commitment;

   b) Changes to the Day Ahead and Hour Ahead Markets;

   c) Changes in the calculation of the Target Price (Economic Dispatch), which was previously approved by the Board and filed by the ISO as part of the proposed Tariff Amendment No. 42 but which FERC rejected for not being part of a comprehensive design;

   Market Power Mitigation Elements:

   d) Modified Must Offer Obligation;

e) 12-Month Market Competitiveness Index, and;

f) Other measures, in support of the above elements, including penalties for uninstructed deviations, negative Damage Control Bid Cap, recovery of emissions costs, and local market power bid mitigation.

And,

3) Directs Management to prepare and file items 1 and 2 with FERC by May 1, 2002, concurrent with the long-term Comprehensive Market Design plan.

Moved: Geesman Second: Florio

Board Action: **Passed** Vote Count: **5-0-0**	
Finney	Y
Florio	Y
Geesman	Y
Guardino	Y
Kahn	Y

Attachment V

Comments of the Market Surveillance Committee of the California ISO on the Proposed October 1, 2002 Market Power Mitigation Measures

by

Frank A. Wolak, Chairman; Brad Barber, Member
James Bushnell, Member; Benjamin F. Hobbs, Member

Market Surveillance Committee of the California ISO

April 22, 2002

Summary of Comments

We endorse the general framework of the ISO's proposed market design. In particular, we agree that strong protections against excessive market power are necessary given the current market structure. However, these measures also create additional costs, and a central goal of the new market design should therefore be to reduce reliance upon these market power mitigation measures. The most effective way to do so is to facilitate more active demand-side participation in the wholesale market.

In particular, we make the following recommendations on the ISO's proposed market power mitigation measures.

1. The establishment of a damage control bid cap (DCBC) of $250/MWh that can be adjusted in the event of a significant increase in natural gas prices.

2. The adoption of automatic mitigation procedures (AMP) or similar measures to mitigate the exercise of local market power. The mitigation of local market power is a critical component of the overall market design.

3. The establishment of a 12-month competitiveness index that can monitor a level of aggregate performance of the market over a time horizon longer than do the AMP and DCBC measures.

4. The creation of an index of available capacity (ACAP) that would, at least in the near term, provide to the public advance notification of the ability of the various load-serving entities (LSEs) to satisfy their load obligations. We believe the question of the appropriate penalties for failure to acquire sufficient ACAP in the long-run warrants further discussion. We do strongly endorse the principle that LSEs, and not the ISO, should bear ultimate responsibility for ensuring the availability of sufficient resources to satisfy their load obligations.

Introduction

We have been asked to comment on the California ISO's proposed market power mitigation measures to be implemented October 1, 2002. At a later date, we will comment on aspects of the ISO's comprehensive market re-design dealing with transmission congestion management. However, we would like to emphasize that the ISO's congestion management protocols were not the cause of the crisis of the past two years. The primary cause was an underlying market structure that was insufficiently competitive. Reforming the ISO's congestion management protocols can somewhat mitigate the consequences of these structural problems, but these changes will not be sufficient to achieve a robust, competitive, and reliable electricity market in California. To reach that goal, more fundamental structural changes are necessary.

The greatest structural problems in the California market from 1998 through 2000 were the asymmetric treatment of final consumers and producers of electricity, the lack of sufficient forward contracting by load-serving entities (LSEs), and the local market power of some suppliers. The long-term contracts signed by the State of California during the spring of 2001 significantly reduced the reliance of consumers on the short-term markets. Implementing this solution was extremely costly to California consumers, because these long-term contracts were voluntarily entered into by firms serving the California market. Therefore, the terms of these contracts reflected the enormous amount of market power that the suppliers expected to exist in the spot market in subsequent years had these long-term contracts not been in place.

The existence of transmission constraints within the ISO system remains a structural problem that continues to give suppliers local market power. There are obvious limits to the extent that new transmission or generation facilities can relax these constraints. The California ISO must have mechanisms to mitigate the local market power of suppliers. Such measures have been adopted and approved by FERC for all east coast ISOs and it is important for California to have comparable measures.

The critical remaining structural flaw in the California electricity market and all other US wholesale electricity markets is the asymmetric treatment of suppliers relative to end-users of electricity. Suppliers in all US ISOs participate in a market with prices that can vary significantly over time and location. The prices paid to generators can change as frequently as every 5 minutes at potentially thousands of locations in the ISO control area. In contrast, virtually all end-users in California and all of the states served by the eastern ISOs pay prices that are adjusted infrequently, if at all, and are the same over large geographic areas.

Many of the elements of the ISO's new congestion management proposals are designed to provide more variation in wholesale prices by *location*. While we feel that this is a worthwhile goal, it is even more crucial to provide to end-users more variation in prices by *time*. The wholesale prices earned by suppliers are much more volatile with regards to time than across locations for a given time period. More importantly, the most effective way to reduce supplier market power is to construct a system in which an attempt to raise prices would result in lost sales. Giving end-users the ability to alter their usage patterns and refuse to purchase power at extreme prices would provide an important counterbalance to the market power of suppliers. Unfortunately, this most critical element of a functional electricity market has been lacking in California and throughout the US.

Because of the asymmetric treatment of load and generation, procedures to mitigate supplier market power are an essential part of any market design for California, as they currently are for the east coast ISOs. All methods for congestion management--nodal-pricing, zonal-pricing and system-wide pricing--must deal with the local market power problem and the system-wide market power problem. However, we should also caution that there is a false sense of security created by market power mitigation measures that masks their potentially negative short-term and long-term consequences. The short-term consequences stem from their inability to fully and effectively control the market power of suppliers under conditions of system stress. In other words, mitigation measures such as the ones proposed by the California ISO, versions of which are currently in place in the eastern ISOs, are least likely to work when they are needed the most. The long-term consequences stem from the operational and investment choices made by suppliers in response to the incentives provided by the mitigation measures. In many ways, these responses can raise the costs of supplying power and thereby inflate prices over time.

In short, there is no free lunch when it comes to mitigating market power. There are measures that can be taken to limit prices in a given hour, but usually at the cost of raising prices in other hours or by threatening system reliability. In circumstances where buyers in the market are trying to buy power, regardless of price, and there is insufficient competition among suppliers, sellers will always be able to put pressure on the ISO to exempt them from price mitigation. Unless an entity such as FERC is willing to coerce suppliers to offer power at mitigated prices, the ISO will have to choose between the integrity of its price controls and the integrity of the electric system.

Measures such as the ISO's proposed Available Capacity (ACAP) requirement can be used to reduce the chance that the ISO would be left in such a situation, but at the cost of paying ACAP resources. Providers of ACAP would be required to supply power to the ISO system in a manner that is consistent with the ISO's mitigation measures. In other words, an ACAP payment is made to suppliers for their consent to provide power at potentially lower prices than they otherwise would have earned. In this way ACAP is essentially `buying out' the market power of suppliers rather than eliminating it, unless the supply of new generation is sufficiently elastic and enough lead-time (2-3 years or more) is allowed to acquire ACAP. In the absence of an ACAP mechanism, it is not practical to expect suppliers to voluntarily give up their market power in times of tight supply. If there is a cap on the price load-serving entities must pay for ACAP capacity (either in the form of an explicit price cap or a $/MW penalty on load-serving entities for failing to meet their ACAP requirement) and generators are not compelled to offer their capacity in the ACAP market below that penalty level, the ISO may be forced to choose between maintaining reliability or maintaining this price cap if generators have market power in the ACAP market. This sort of market power problem has occurred in the PJM Installed Capacity (ICAP) Market. Despite a requirement for all generators to bid into the ICAP market, those firms with market power were only willing to sell ICAP capacity at prices above the $/kw penalty to load-serving entities for ICAP inadequacy.

Despite our concerns about the costs imposed by market power mitigation measures, they are still preferable to allowing the unfettered exercise of market power in a market that is unable to support competition. However we believe that it is much less costly in the long-run to correct the underlying structural problems that make these regulatory measures necessary. We strongly urge all the parties involved in the California electricity market to make demand-side participation in the market a centerpiece, rather than an afterthought, of market power mitigation.

ISO Market Power Mitigation Plan

The ISO proposes both a short-term and long-term approach to market power mitigation. For a variety of reasons, the ISO does not believe it is possible to implement an ACAP requirement in the short-term. Given current supply and demand for generating capacity in the western US, it is very likely that in the short-term, at least one entity is pivotal in the ACAP market. Consequently, the ACAP market is very likely to be subject to significant market power at time horizons shorter than the time necessary to site a substantial amount of new capacity in California. In addition, the ISO envisions implementing local ACAP requirements to account for known transmission constraints throughout the ISO control area. Creating local ACAP requirements will further exacerbate the market power problems associated with implementing ACAP in the short-term and even in the long-term. For example, it is highly unlikely that additional generating capacity can ever be built in certain local areas, such as in the City of San Francisco. Consequently, the only time horizon which a workably competitive local ACAP market in San Francisco could operate would be at the horizon necessary to credibly construct new transmission capacity into San Francisco, which is considerably longer than the time necessary to build new generating capacity.

For all of these reasons, we strongly agree with the ISO's perspective that an ACAP market is not practical over the short-term. Moreover, we believe that several of these factors call into question the viability of a workably competitive ACAP market over the 2-3 year forward market horizon without intervention by FERC to cap the prices paid to generation unit owners for providing local ACAP.

In spite of our reservations about the viability of a workably competitive ACAP market, we strongly endorse the concept of holding load-serving entities (LSEs) responsible for supplying sufficient generating capacity or equivalent quality negawatt capacity to the ISO to operate a reliable transmission network. The residual unit commitment (RUC) process is designed to deal with the problem of under-scheduling on a daily basis. However, we are not convinced that the current ACAP proposal is the least-cost mechanism for implementing that requirement over the long-term.

Obviously, a first step in the process of assigning any ACAP or analogous obligation would be a determination of what entity is responsible for purchasing wholesale electricity. Particularly, for the portion of the state served by Pacific Gas and Electric, it is unclear what entity will purchase wholesale electricity on January 1, 2003. Until there is more clarity on what entities will be purchasing electricity, it is impossible to determine the least-cost long-term mechanism for providing sufficient capacity to the ISO for reliable grid operation.

For these reasons and because California is a net importer of electricity, we believe the best course of action for short-term market power mitigation is to extend the June 2001 FERC west-wide mitigation order until it is determined what entities will be responsible for purchasing electricity after December 31, 2002. A contributing factor to the crisis of the past two years in California was the disconnect between California's retail market design and its wholesale market design. Relying on the demand side of the wholesale market to provide significant market power mitigation is imprudent given current conditions in the retail sector the California market. However, we strongly urge all parties at the state level to facilitate the active participation of load in the ISO markets through the installation of interval meters and retail pricing programs that allow final consumers to participate in the hourly markets in the same manner as a generation unit owner.

If it is not possible to extend the June 2001 FERC west-wide mitigation order beyond October 1, 2001, we believe the following market power mitigation proposal should be implemented. First, the ISO should implement a damage control price cap of \$250/MWh. To ensure the ISO has sufficient capacity during periods in which it may need energy most, we do not advocate setting the price cap any lower than \$250/MWh, assuming that natural gas prices remain in the \$2.50/MMBTU to \$4.00/MMBTU range. Because of the quantity of forward contracts for electricity signed by the state of California during the spring of 2001, the exposure of California load to spot price fluctuations should be significantly less than it was during the summer and autumn of 2000 and winter of 2001. Consequently, the harm to consumers in terms of higher wholesale electricity costs associated with hitting the \$250/MWh price cap is significantly less than it was during the previous year. The benefit of setting a relatively higher cap is that the ISO will be more likely to be able to attract sufficient energy in the short term and generation capacity in the long term to the California market to operate the transmission network reliably.

Even though the ISO has a number of generating units under Reliability Must-Run (RMR) contracts that it can call to mitigate local market power, system conditions often occur when generating units besides RMR units are able to exercise local market power. Consequently, we strongly support the implementation of an automatic mitigation procedure (AMP) on all generating units that possess local market power according to a clearly articulated criterion. For example, if the ISO determines that at most three generation owners are able to provide a local energy need, then the bids submitted by these market participants will be subject to an AMP.

FERC is currently considering whether to modify or void the forward contracts signed by the state of California during the spring of 2001. Because of the enormous uncertainty about the final quantity of forward contracts held by the state and uncertainty surrounding the final structure of the retail market in California, we do not think it is possible to provide a specific recommendation on the final component of the market power mitigation proposed by the ISO—the available capacity (ACAP) requirement. We only note that for the reasons cited above, we are not convinced that an ACAP market is likely to be the least cost (to consumers) approach to providing the capacity required by the ISO. We discuss the ACAP requirements in further detail below.

Moreover, without explicit mitigation of the prices paid for ACAP capacity in certain locations in the ISO control area, purchasers of the ACAP obligation will find themselves paying for the local market power that a unit has in the energy market (albeit in advance), at least in the short run. In this way local market power in the energy market is transferred to the ACAP market.

12-Month Competitiveness Index

The last element of the ISO's proposed market power mitigation measures is the 12-month competitiveness index and its use as a trigger for stronger mitigation measures. The index is designed to provide a high level, longer-term evaluation of the overall competitiveness of the market. The basis of the index would be a comparison between actual market prices and an estimate of what prices would have been if no firm had attempted to exercise market power. If the 12-month rolling average of this measure crosses a pre-specified threshold, then an additional layer of stronger mitigation measures would automatically be triggered. A key requirement for this mitigation measure is that all of the market participants would find it in their financial interest to avoid exceeding this threshold. If the mitigation measures that occur when the threshold is exceeded are perceived as sufficiently Draconian by all market participants, each will have a strong financial incentive to work to correct the market flaws that allowed the index to approach this threshold. In this sense, the market will be self-regulating by providing incentives for all market participants to fix small design flaws before they can develop into problems that result in large wealth transfers.

Such a long-term measure can also be a very useful diagnostic tool. Unusual problems with unit outages, trading decisions, data collection, and a number of other factors can make a short-term measure of market performance unreliable. Even severe levels of market power can have minor consequences if limited to a small number of hours. An annual measure can overcome many of these shortcomings. The presence of an explicit threshold on the annual level of market power can also permit less stringent thresholds to be set on short-term mitigation measures such as AMP and hourly price-caps.

The ISO's experience during the summer of 2001 is an excellent example of how the automatic implementation of strong mitigation measures can serve as a powerful self-regulating influence on suppliers in the market. The FERC's June 19th order would reset the West-wide price cap if the system enters an hour of a stage 1 system emergency. The cap was initially set in June of 2001 using a significantly higher gas price than those experienced during the summer of 2001. Consequently, suppliers had a very strong incentive to bid sufficient capacity into the ISO's real-time market to ensure that a one-hour period of a Stage 1 emergency did not occur. If it did, the price cap would have been adjusted downwards using the significantly lower natural gas prices that prevailed during the summer of 2001. The ISO operators report that, in contrast to previous summers, suppliers were eager to supply to the California market during the unexpectedly high demand conditions of the summer of 2001 in order to prevent a Stage 1 emergency. A properly implemented competitive index (with an explicit 12-month threshold) would create incentives for the market to self-regulate and thereby not to be subject to significant long-term market power.

Because of these advantages, we strongly endorse the concept of a rolling 12-month competitiveness index. Before this index can be implemented, there are several issues raised by stakeholders that need to be addressed, none of which is a reason to reject the concept. These are discussed below.

1.) **Transparency**. It is critical for such an index to be transparent to all market participants. This may involve simplifying the calculation of the competitive benchmark in order to make the algorithm more transparent and to accommodate data confidentiality policies.

2.) **Threshold**. The two primary options for a threshold level are the percent mark-up of market costs over competitive costs and/or a ($/MWh) level of average market costs over competitive costs. Although more analysis of this question is needed, our sense is that the percent mark-up is likely to be more sensitive to movements in external factors such as gas prices, and thus will be more likely to trigger a `false positive' result than would a fixed ($/MWh) threshold. The fixed threshold would also provide a stronger incentive for firms to reduce their costs than would the percent mark-up. Lastly, the fixed threshold can be more easily linked to the long-term average costs of new generation, since the nominal level of the percent mark-up would grow as costs rise. For these reasons, we favor fixed $/MWh difference rather than a percent mark-up as the threshold.

3.) **Measurement of market costs and prices**. Though there are complications in the measurement of market costs and prices which are necessary for the construction of a competitiveness index, we believe these can be satisfactorily addressed. Without an established transparent forward energy market, the measure of market price becomes more complicated. One option would be to use the imbalance energy price in the ISO. If the spot market is not very liquid, this may not be a very accurate signal of market costs. We would not advise using a measure of the average cost of purchased power that includes forward contracts of duration longer than 12 months. These contracts would reflect the conditions of the market at the time they were negotiated, rather than during the time the index is intended to measure. The transition to locational marginal pricing (LMP) will require further modification of the calculation.

4.) **Consequences of Exceeding Threshold.** The ISO proposal suggests that cost-of-service measures should be implemented. In general, the consequences of violating the threshold should be sufficiently unattractive that no market participant (buyers or sellers) would risk doing so. The severity of such measures implies that the threshold should be set high enough that the prospect of triggering it in error is remote. A higher threshold also ensures that buyers would prefer continued market operation to triggering the threshold level.

Maintaining Reliability in the California ISO Control Area

A core principle of the ISO's market design is that load-serving entities bear the responsibility for ensuring the availability of adequate resources for satisfying their load obligations. We strongly endorse this principle.

The current ACAP proposal can serve a very useful informational role in achieving this goal. By tracking which LSEs are being responsible in the procurement of supply, the ISO provides useful information to consumers and regulatory bodies. In the short-run, this information would be most useful to regulatory bodies, since end-use consumers have little choice in selecting an energy service provider (ESP). However, a critical element of a successful market design, as we have emphasized repeatedly, is retail prices that reflect market conditions. Time and location are two important determinants of market-determined prices; the reliability of an energy service provider is a third. In the long-run, we envision a retail market populated with many ESPs. The current ACAP proposal would provide information that would allow the ISO to rate the reliability of ESPs, much as bonds are rated in financial markets. The market prices charged by ESPs would reflect their reliability ratings, much as the interest rates paid on bonds reflect the creditworthiness of the issuer. In short, we strongly endorse tracking ACAP as an important informational tool.

Unfortunately, we are currently in a market where three investor-owned utilities serve the vast majority of load in California. The retail rates that they charge are fixed. End-use consumers cannot vote with their feet (by changing ESPs). Thus, should ACAP be required, with pecuniary penalties for failing to meet ACAP requirements and ultimately curtailment of LSEs who do not meet ACAP requirements? We strongly endorse the notion of curtailing those LSEs who fail to meet their obligation to serve (rather than curtailing the entire system). This is the ultimate penalty that befalls those who violate the proposed ISO ACAP requirement. There are pros and cons to adding intermediate (day ahead and month ahead) financial penalties for failing to meet ACAP requirements. On one hand, financial penalties would ensure that LSEs are properly planning for their load requirements. On the other hand, intermediate financial penalties may lead to overprocurement, a cost ultimately borne by consumers. This tradeoff needs to be carefully scrutinized before we can reach a clear conclusion on the issue of intermediate financial penalties. (There is also the thorny issue of what generation and demand-side reduction programs would qualify for satisfying the ACAP requirement.) However, there is one clear conclusion. LSEs that fail to procure sufficient supplies to meet their demand should bear the consequences of that failure. LSEs that responsibly fulfill their obligation to serve should not be penalized for the poor behavior of other market participants.

No matter what mechanism is adopted by the ISO for dealing with the question of long-term adequacy of supply, the incentives provided to LSEs by local regulators will still be critical to supporting it. Given that both the ISO and other California authorities place paramount importance on maintaining reliability, we urge that a mechanism satisfactory to all parties be developed. It is important to note that even if ACAP is adopted in its current form, it would not become effective for several years. In the meantime we will have to develop alternative means to ensure system reliability.

Attachment W

MARKET POWER IN CALIFORNIA

ISO Markets have never been found to be competitive at all times and under all conditions.

- In its October 18, 1999 Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets, the ISO Market Surveillance Committee ("MSC") stated,

> We find that significant market power remains in California's wholesale energy markets during periods of high total system load, which primarily occur during the summer months.
>
> * * * *
>
> During these periods, price movements across hours of the day are significantly in excess of the increased costs of supplying power during these hours. . . . This is a direct indication of market power.[1]

- On September 6, 2000, the MSC issued its analysis of the June 2000 Price Spikes in the California ISO Energy and Ancillary Services Markets, finding that:

> [d]uring the months of May and June 2000, wholesale revenues from sales of total ISO load (less must-take energy) for all hours of the month in the California energy market were approximately 37% and 182%, respectively above monthly revenues under perfectly competitive pricing.[2]

The MSC concluded that the California electricity market:

> [i]s composed of a relatively small number of firms, some of which own a sizable fraction of the total electricity generating capacity located in the ISO Control Area. The geographic

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[1] *Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets*, Docket Nos. ER98-2843-000, *et al.* (Oct. 19, 1999), at 1 and 7-8. The MSC found that actual costs during the summer of 1999 were approximately 20 percent above those predicted by the MSC's benchmark market analysis, an analysis designed to measure deviations from prices that would be associated with a market that is workably competitive. *Id.* at 8.

[2] *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets* at 2. This report and other MSC reports cited in these comments can be found on the ISO Home Page at <http://www.caiso.com/surveillance/overview/Committee.html>.

> distribution of generation unit ownership can allow some owners to exercise locational market power during certain system conditions. In addition, the amount of generating capacity owned by some market participants allows them to exercise market power during high load conditions, *when there is not a physical scarcity of available generating capacity to serve this load.*

Id. at 5 (emphasis added).

In an affidavit filed with the Commission in this proceeding on October 20, 2000, Dr. Eric Hildebrandt of the ISO's Department of Market Analysis ("DMA") presented results of a systematic, quantitative analysis of market power and scarcity over the first two and one-half years of ISO operations. Results of this analysis showed that a significant degree of market power was exercised during the months of May to September 2000. Dr. Hildebrandt noted that:

> While a significant portion of the increase in wholesale costs above this competitive baseline have been incurred during hours of potential absolute resource scarcity, the bulk of these additional costs are attributable [to] a lack of competition, rather than scarcity. In addition, prices continued to significantly exceed competitive levels even after the ISO's real-time price cap was lowered to $250 in August.[3]

- A DMA report submitted with the ISO's comments on the Commission's November 1 Order proposing solutions to the continuing crisis in California markets[4] presented the results of a quantitative analysis by DMA staff of the impact of market power and other factors on market costs. As explained in this report:

> [S]ince late May of this year [2000], the combination of very tight supply and demand conditions – in conjunction with very limited ability of consumers to reduce consumption in response to high prices – has created the opportunity for the persistent exercise of market power in California's wholesale energy markets. The exercise of this market power has inflated wholesale energy costs significantly above levels that would have resulted under competitive market

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[3] Declaration of Eric Hildebrandt filed with Proposed Offer of Settlement in Docket Nos. EL00-95 *et al.* on October 20, 2000 at 5-7.

[4] *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 93 FERC ¶ 61,121 ("November 1 Order").

conditions, even after taking into account fundamental market factors driving up costs and hours of potential scarcity of supply. While some degree of market power may be tolerable from the perspective of defining a workably competitive market, the exercise of market power since late May of this year has clearly exceeded the level that may be considered consistent with a workably competitive market. Since additions of new supply are likely to merely keep pace with or even fall short of demand growth over the next two years, the exercise of significant market power can be expected to continue – if not worsen – over the next two years absent action to more effectively mitigate system-wide market power.[5]

- The studies by Dr. Hildebrandt and Dr. Anjali Sheffrin attached to the ISO's March 22, 2001, Comments in on Staff's "Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market" in Docket Nos. EL00-95, *et al.*, provide further evidence that market power was being exercised widely under all market conditions.[6] Specifically, these studies demonstrate that Market Participants can affect market prices in California by altering output or bid prices during a wide range of system conditions, not just in those hours where a deficiency in Operating Reserves requires the ISO to declare a System Emergency.[7]

- On April 2, 2001, the ISO filed a protest of the compliance filing of Williams Energy Marketing & Trading Company ("Williams") in Docket No. ER99-1722-004. The ISO attached additional analyses from the DMA

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5 *See Analysis of Market Power in California's Wholesale Energy Markets*, Attachment A to the ISO's November 22 Comments on the November 1 Order in Docket Nos. EL00-95 *et al.*, at 9.

6 The ISO incorporates by reference Dr. Hildebrandt's study, Dr. Sheffrin's study, and the responses to a March 30, 2001 letter from Mr. Daniel Larcamp, the Director of the Commission's Office of Markets, Tariffs and Rates relating to those studies.

7 DMA estimates that 31 percent of the total energy costs during non-emergency hours for the period of March 2000 to February 2001 are attributable to the exercise of market power. Though the average markup above competitive levels during non-emergency hours is lower than in emergency hours, because there are many more hours of non-emergency conditions, the cost impact of market power is much higher than in emergency hours. In fact, by these estimates, the cost impact of market power during non-emergency hours represents over 54 percent of the total cost impact of market power in all hours. This analysis suggests that limiting mitigation to emergency hours would address less than half the cost impact of market power. *See* Dr. Hildebrandt's March 2001 report, *Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market*. This study was attached to the ISO's Comments on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, filed in Docket No. EL00-95-12 on March 22, 2001.

showing that Williams engaged in either physical or economic withholding during *every* hour of the May 2000 through November 2000 period, and that subsequent to the Commission's termination of the ISO's price cap authority, Williams's exercise of market power was even more pronounced, resulting in revenues from the ISO real-time market for the months of December 2000 through March 2001 that were almost twice (173 percent) its estimated operating costs.

- The ISO's Second Quarterly Report[8] reported that, for the period of September through November 2001, the ISO continued to see certain suppliers submitting energy bids well in excess of their proxy bid cost, *i.e.*, incremental cost. Approximately 20 percent of the total volume bid into the ISO BEEP stack in September and October 2001 had prices above the $91.87/MWh Non-Emergency Clearing Price Limit.

- The ISO's Third Quarterly Report[9] provided extensive data demonstrating the extent that market power continues to be a factor in the California energy market. Analysis of the bidding of individual suppliers showed that at least four of the five major owners of gas-fired generators have consistently bid significant amounts of capacity well in excess of variable operating costs. Moreover, bid prices appear to remain relatively constant, rather than reflecting significant variations in spot market prices over time, the heat rates of different units, or other factors that would be expected to affect bid prices under competitive conditions. In addition, 70 to 80 percent of the capacity from combustion turbines, as well as significant quantities of excess capacity from on-line steam units, have been bid into the Real Time Market at prices at or near the price caps that have been in effect.

  The ISO's analysis in the Third Quarterly Report also demonstrated that numerous suppliers have bid into the Real Time Market excess capacity from steam units that are on-line and scheduled to operate at prices far in excess of marginal costs. For example, the average bid price for these units in October 2001 was about 75 percent higher than marginal costs. The ISO also observed "hockey stick" bidding where suppliers bid all

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[8] *Second Quarterly Report of the California System Operator Corporation*, FERC Docket Nos. EL00-95-000 *et al.*, filed December 14, 2001 in response to the Commission's April 26, 2001 and June 19, 2001 mitigation orders in *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange*, 95 FERC ¶ 61,115 and 95 FERC ¶ 61,418 (2001), at 5-6 ("Second Quarterly Report").

[9] *Third Quarterly Report of the California System Operator Corporation*, FERC Docket Nos. EL00-95-000 *et al.*, filed March 26, 2002 in response to the Commission's April 26, 2001 and June 19, 2001 mitigation orders in *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange*, 95 FERC ¶ 61,115 and 95 FERC ¶ 61,418 (2001), at 27-45 ("Third Quarterly Report").

peaking capacity (combustion turbines) at a price at or near the price cap, while bidding excess capacity from on-line steam units at prices that are somewhat lower (but often still significantly in excess of marginal costs).

Following the Commission's June 19 Order, Western regional Spot prices dropped from over $120/MWh to under $60/MWh in two days. While prices increased for a brief period in late June and early July 2001 due to a heat wave in the Southwest, overall prices remained below the "soft cap" level of $91.87/MWh, except at Palo Verde. Following this brief occurrence of prices above the cap, prices continued downward and stabilized between $20/MWh and $30/MWh.[10] The ISO believes that these prices confirm that the Commission's *comprehensive* mitigation measures have been effective in moderating prices throughout the Western *regional* marketplace.

10 Third Quarterly Report at 19.

Attachment X

NOTICE SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas and Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents,	)	**Docket No. EL00-95-001, et al.**
California Independent System Operator Corporation	)	**Docket No. ER02-___-000**

Notice of Filing

[ ]

Take notice that on May 1, 2002, the California Independent System Operator Corporation ("ISO") tendered for filing in the above-captioned dockets its proposals for a Comprehensive Market Redesign. The ISO requests that certain elements of the filing be made effective on July 1, 2002 and others on October 1, 2002. The ISO states that this filing has been served on the California Public Utilities Commission, all California ISO Scheduling Coordinators, and all parties in Docket No. EL00-95.

Any person desiring to be heard or to protest the filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). All such motions or protests must be filed in accordance with § 35.9 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).