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. EL00-95-000
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket No. EL00-98-000
Public Meeting in San Diego, California	)	Docket No. EL00-107-000
California Power Exchange Corporation	)	Docket No. ER00-3461-000
California Independent System Operator Corporation	)	Docket No. ER00-3673-000

COMMENTS OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
ON THE
ORDER PROPOSING REMEDIES FOR CALIFORNIA
WHOLESALE ELECTRIC MARKETS

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I. **Introduction**

In his prepared written statement that was entered into the record of this proceeding at the November 9, 2000conference, Terry Winter, President and Chief Executive Officer of the California Independent System Operator Corporation ("ISO"), stated:

> I harbor no illusion that your Order of November 1st will put discord to rest. I do, however, cling to an overriding hope: that each constituency with a stake in California's electric markets will recognize the need to suppress differences and choose, instead, to build on the commitment to restructuring that we share.

Now, after participating at and reviewing the record of the November 9thconference, the ISO is even more optimistic about the future of California's restructuring effort, indeed, about the evolution to a regional marketplace. The ISO is encouraged by the convergence evident at the conference and in the written submissions, coming from all quarters: from utilities both public and private, from generators, from consumers, and from their political leaders:

- There is near universal agreement that until there is a sufficient margin of supply in excess of demand, some measure of price mitigation is appropriate;
- There is apparent agreement that peaking units, with their unique cost structure, must be compensated in a way that encourages their development.
- There is agreement that the real time market, a market that the ISO believes it will always have to operate, should be limited to a true balancing function;
- There is agreement that the prescheduling of supply and load should be encouraged in ways that do not distort bargaining leverage for supply contracts and that the overwhelming bulk of that prescheduling, at least for the next several years, take the form of forward contracts; and

- There is agreement that the Stakeholder Board, which played a critical role in the legitimacy of California's movement toward a competitive paradigm and in its nurturing, should now evolve into an Independent Board better situated to promote the resolution of the issues confronting California in the regional context from which those issues are inseparable.

That many participants would design the details proposed in the Order differently is not at all surprising. That all have expressed confidence in the Commission's direction and a willingness to work cooperatively, proves that the enormous effort that went into the November 1st Order and accompanying Staff Report was effort well spent.

The ISO itself has concerns about constituent elements of the proposals in the November 1st Order, on the basis both of substance and of implementation – feasibility and timing. Those are the questions that we each should be focusing on; those are the subject of the discussion that follows. The ISO will address the following major issues: governance, system-wide market power mitigation, underscheduling, congestion management, and locational market power mitigation.

The ISO is concerned, for example, about the bifurcated market mitigation strategy that has been suggested: specifically, that the "As Bid" component will become the rule, not the exception, requiring an enormous market monitoring and cost review effort and leaving ultimate costs uncertain for prolonged periods.

The ISO submits that a preferable approach would be to establish "safe harbor" price benchmarks. Bilateral contracts negotiated at levels not in excess of those benchmarks would be deemed just and reasonable.

The encouragement of bilateral contracts, covering a substantial portion of the demand that must be met by load-serving entities, is absolutely key. But if those negotiations are to produce results that more closely reflect a competitive market, the scale must be balanced. Underscheduling must be penalized, whether by supply or load. In addition, forward contracting must be demanded of both, but on a level playing field. In those respects the proposals in the November 1st Order require modification.[1]

Very recent events underscore the critical need to implement solutions to the problems addressed in the November 1st Order. During the week of November 12, 2000, approximately 11,000 MW of generating unit capacity was either forced or planned to be out of service. These outages required the ISO to declare a Stage 2 Emergency (dropping interruptible load) on three consecutive days. The crises of the summer have followed us into the winter period – and will continue to threaten the reliability of California's electricity power system until the root causes are directly removed. We welcome the timely resolution that this proceeding promises.

II. Governance

One issue that, understandably, evokes a high level of emotion in California is the governance structure of the ISO. It is an area that, if not handled with particular sensitivity and a willingness to cooperate, can lead all parties on tangents and create prolonged uncertainty that can only disserve the consumers that are the intended beneficiaries of restructuring. That must not and need not be allowed to happen.

If the ISO is to make the contribution of which it is capable to a regional, competitive marketplace, indeed, if the ISO is to be in a position to make the contribution required of it for the benefit of consumers in California, it must have a

[1] The ISO is also concerned that a market power mitigation strategy applied only to resources within California both ignores the regional nature of the market and complicates the monitoring of transactions that begin as exports out of California.

governance structure that is well suited to respond to the regional marketplace upon which those consumers depend and within which California's electric markets must operate. At the same time, if the ISO is to discharge functions that reside within historic state jurisdiction, the State has a legitimate role in the Board selection process.

Part of the key to encouraging the desired cooperation may lie in a clarification of ISO responsibilities. The ISO believes that a critical focus of its responsibilities is the development and operation of an integrated transmission network that is capable of delivering reliable power and bringing to the consumers of California, and to neighbors in the west, benefits -- innovation and efficiency -- that competition can best provide. That the ISO has from time to time assumed responsibilities that necessarily impact retail rates, that it has taken steps to kick-start supply acquisition, cannot be disputed. In many instances, these are functions thrust upon the ISO by circumstance, not functions that the ISO covets as part of its on-going responsibilities. ISO management and its Governing Board stepped in to fulfill these functions because each believed it had no alternative, given the statutory responsibility of the ISO to maintain grid reliability. On a going-forward basis, however, the ISO would welcome developments within California that would enable it to direct its efforts to the areas identified as appropriate to a Regional Transmission Organization ("RTO") under Order No. 2000. To the extent that these activities impact areas within the purview of state authorities, state input can be assured while allowing the ISO to operate under a Board structure that is consistent with the regional nature of electric markets in the West. Even where the ultimate decision is of interstate character and within the ultimate authority of the

FERC, an Independent Board structure still can accommodate state input on issues of local interest, through advisory committees or other creative solutions.

With the continued leadership of this Commission, successful resolution of this issue as well will prove far less daunting.[2] The ISO is concerned, however, that the Commission's directive regarding governance raises a potential implementation concern. The governance proposal in the Order creates a conflict with California statutes that must be resolved, preferably by agreement among all concerned. Changes to the Governing Board of the ISO – a California corporation – require the proper adoption of Bylaws setting forth any new governance structure. As the Commission is aware, as permitted by California law, the ISO's Bylaws require Electricity Oversight Board approval for certain amendments regarding appointment of Board members currently subject to state confirmation.[3] The Electricity Oversight Board currently is prevented from approving such amendments by California Senate Bill 96 ("SB 96"), which "freezes" the current ISO Governing Board structure until other states are participating in the ISO under a negotiated interstate compact or California passes additional legislation.[4] Without changes to state legislation, any actions taken

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[2] As Terry Winter indicated (November 9th Tr. at 52), the ISO does not believe that implementation of the likely outcomes of the proposals in the November 1st Order will interfere with the ISO's timely compliance with Order No. 2000. To the contrary, the issues to be addressed in this docket should help clarify the ISO's responsibilities moving forward.

[3] Currently, the precise provisions of the ISO's Bylaws subject to Electricity Oversight Board approval are not easily defined, as the EOB has rejected the ISO's initially-proposed designation of provisions subject to EOB approval. Nevertheless, California Senate Bill 96 and the Commission's currently-effective Declaratory Order both recognize that EOB approval of certain ISO structural governance changes is appropriate. California Electricity Oversight Board, 88 FERC ¶ 61,172, reh'g denied, 89 FERC ¶ 61,134 (1999); appeal pending.

[4] In addition, the California State Constitution requires the Electricity Oversight Board to continue enforcing statutes, such as SB 96, that arguably are in conflict with federal laws or regulations until directed by an appellate court. Cal. Const. Art. III §3.5.

by a newly-seated Independent Board might be challenged as not taken by a Board properly seated under state corporation law and other statutes. This conflict in state and federal requirements should be resolved in order to avoid confusion. The ISO accordingly believes that this portion of the Commission's Order (or any alternate proposal) may require more than ninety days to implement.

Given the law in California, it is imperative that all parties cooperate in developing an independent governance structure that provides an appropriate opportunity for state input. We believe it is appropriate to look to the other independent system operators and the formation of their independent boards for guidance on this matter.

Each has used an independent search consultant (firm) with board selection experience and we feel this is an appropriate mechanism to manage the candidate solicitation and screening process. As in the other searches, the firm would generate and qualify candidates from the firm's substantial resources as well as collect and qualify the candidates brought forward by stakeholders in the state and region. Working with the firm, the CEO and a selection committee would develop a set of qualifications similar to those used to select the Boards at the other independent system operators and consistent with those outlined in the November 1st Order. With the other independent system operators, the memberships of these selection committees has varied from a group composed entirely of investor-owned utility representatives to a group made up of stakeholders from a series of defined groups. We would propose using a selection committee of six current Board members and two representatives of the State. The Committee would also include the CEO of the ISO.

This committee would narrow the firm's slate down to 12-18 candidates (2-3 candidates per slot, excluding the slot for the CEO). The final six candidates would be selected by the current ISO Board.

We believe this type of process would result in a Board that can both represent the needs of California and make the necessary independent and prudent decisions for the ISO and facilitate required solutions.

III. <u>Market Power Mitigation</u>

It is not necessary to cast aspersions about the activities of market participants, or to reach judgments about the use of market power, to conclude that for significant periods of time, prices in California's wholesale markets have been far higher than is to be expected in competitive markets. See Attachment A, an analysis prepared by Dr. Eric Hildebrandt of the ISO's Department of Market Analysis ("DMA"). The problem, in a nutshell, is tight supply, concentrated ownership and lack of demand elasticity. This provides an opportunity for market power to be exercised. When California made its flash-cut to a competitive paradigm, assumptions were made about the pace of entry of supply that have since proven to be unrealistic. The back-up supply contracts that protect load-serving entities and their customers in the East were not put in place.

The Commission's proposal as advanced in the November 1st Order, while well considered, may not suffice. If forward contracting were at an appropriate level, it can be anticipated that the unacceptable consequences of excessive price spikes could be ameliorated.[5] But those contracts will only be at acceptable cost levels if they are negotiated in the context of a well-structured market power mitigation construct.

The ISO approaches the formulation of an appropriate mitigation design with the objective of encouraging forward contracting at prices that more closely approximate cost-based just and reasonable rates while minimizing the potential for prolonged refund uncertainty. The ISO's concerns with the bifurcated proposal advanced in the November 1st Order are summarized below.

First, the \$150 "soft" price cap may prove too generous for base-load units and may, if history is a good barometer, cause prices to hover at that level for far more hours than marginal clearing costs would justify.

Second, the "As Bid" alternative may produce several untoward results.[6] If, as may well prove the case, many units elect that alternative, actual cost mitigation could prove quite elusive. The ISO understands the logic of incorporating compensation for "opportunity costs" in the assessment of bids above the "soft" price cap. But that, of necessity, introduces considerable uncertainty. We agree that California is part of a regional market. Presumably, prices achievable anywhere within that market that are accessible to a supply source would constitute a foregone opportunity, an opportunity cost. The result, in effect, may be no price "cap" at all, or at least not for a very prolonged period of uncertainty while the issue of legitimate, verifiable opportunity costs is scrutinized. Relief deferred may prove highly unsatisfactory.

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[5] Participants at the public conference on November 9, commented on the significant level of forward contracting in the East and its contribution to relative price stability. November 9th Tr. at 72 (T. Winter), 82 (J. Smutny-Jones).

Third, the ISO is quite concerned that the bifurcated mitigation proposal will increase exports from California with tiered transactions that ultimately rebound back into California but at “As Bid” or Out-of-Market prices that are quite high and extremely difficult to police.

Fourth, if, as the ISO believes, the “As Bid” alternative will distort the bargaining leverage between load and supply, it might not be possible to negotiate short-term or long-term supply contracts at all, or at prices that are consistent with just and reasonable rates.

Fifth, the inevitable consequence of the blending that will be required of supply sold under each half of the bifurcated structure will be the muting of marginal cost signals so critical to the inducement of supply and demand-side response programs. Some portion of the market, albeit a very modest portion, should be given correct price signals in order to create incentives to transition to an efficient market structure.

We believe that, to be effective, the approach proposed in the November 1st Order would require imposition of similar bid caps throughout the Western region with which the California market is integrated. A price mitigation approach applicable only to California markets could give rise to gaming. For instance, California resources could have an incentive to export their power in order to take advantage of higher prices in neighboring states, or to claim those potentially higher prices as opportunity costs of participating in the California market.

The ISO is also concerned that the Commission's approach may actually exacerbate underscheduling. Suppliers may attempt to evade the soft-cap by

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[6] For a discussion of the “As Bid” approach versus a uniform price auction, see the

withholding from the California Power Exchange ("PX") market and providing bids above the soft cap to other forward market exchanges (e.g., the APX) or schedule a bilateral export. Depending on how high these bids are relative to the real-time penalty for underscheduled load, load serving entities may prefer to have their load not clear the PX market and consequently rely on the ISO real-time market. Clearly, this outcome would be at odds with the intent of the November 1st Order.

Finally, the ISO is most concerned about difficulties in implementing the mitigation approach proposed in the November 1st Order. Two concerns are most prominent. If there is to be an “As Bid” alternative available to sellers, with the possibility that the “As Bid” price subsequently would be adjusted down requiring refunds, the ISO will have to record bid-specific information for each bid submitted above the $150 “soft” price cap. In order to permit the ISO to eventually rerun settlements in the event that refunds are ordered, the ISO will have to begin to record such information immediately and to continue to record such information for an extended period – perhaps a year or two. This is not a simple task and could result in market uncertainty for an extended period of time. Under very tight supply/demand conditions, this uncertainty by itself could decrease the supply offered in the ISO's markets and create reliability risks.

There would also be a need to establish a cap on the Adjustment Bids used by the ISO to manage congestion. A hard cap on Adjustment Bids would not work in combination with a real-time underscheduling penalty applicable only to loads and not to generation. With the possibility of a $100/MWh penalty on load for underscheduling,

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paper by John Bower and Derek Bunn provided as Attachment B.

the effective price cap perceived by the market under high load conditions would be $250/MWh. Under high load conditions both load and generation may thus end up bidding noticeable MWh quantities at higher than $150/MWh in the PX unconstrained market. If the PX supply and demand curves intersect above $150/MWh, the PX would set the unconstrained market clearing price to $150/MWh. If there is no congestion, the accepted supply bids above $150/MWh would be paid as bid, and the load would pay an uplift on top of the $150/MWh market clearing price. However, if there is congestion, incremental Adjustment Bids would be limited to $150/MWh, preventing load from submitting meaningful Adjustment Bids. Loads would be exposed to $150/MWh usage charges (or higher, e.g., in cases where congestion must be resolved simultaneously on multiple paths in the face of insufficient Adjustment Bids).[7] This presents the same type of problem that has concerned the PX with respect to the $100 Replacement Reserve cap. The PX wanted the Adjustment Bid cap raised to $350/MWh, but agreed that if compensation for Replacement Reserves were limited to either Capacity or Energy payments, the problem necessitating the $350 price would be abated. The November 1st Order includes a proposal to preclude payment for both Replacement Reserve Capacity and Energy, but because of the differential treatment of a real-time penalty for load and generation, a similar problem persists regarding Adjustment Bid caps.

Regardless of the solution adopted to cap Adjustment Bids, the constrained PX energy market clearing price (i.e., the price load in the PX pays for energy in the

[7] This has indeed occurred in practice, albeit rarely. For example, with a cap of $250 on the Adjustment Bid market, the hour-ahead usage charge on Path 15 was as high as $423/MWH on August 16, 1999, hour 3.

presence of congestion) can exceed the soft cap of $150, even when all energy and Adjustment Bids are below $150. There is a question as to whether the intention in the Order is to cap the constrained market clearing price and pay as-bid, or to allow the market clearing price above $150 to be the basis for payment in such a case.

In order to implement the market power mitigation plan put forth in the November 1st Order, the ISO would have to modify its Scheduling Infrastructure and Scheduling Applications software as well as its Settlements system. The ISO recommends pursuing an automated approach. This would slightly increase the implementation time to approximately four months from the date work commences.[8] It is important to recognize that timelines for other ongoing software development initiatives are driven by FERC-approved or FERC-mandated deadlines. Three initiatives that pre-date the November 1st Order are unbundling of the ISO's Grid Management Charge, implementation of the revised Transmission Access Charge, and collection of the Commission's annual charges under the new methodology recently adopted by the Commission. The need for coordination with this development work informs the estimated implementation time-frame for all major changes contemplated in the November 1st Order.

While sharing what we understand to be the objectives of the bifurcated approach, the ISO offers the following approach in its place which attempts to improve

[8] Implementation utilizing blends of automated and manual processes could be accomplished by January 1, 2001. However, such an approach increases operator intervention in the market and can be extremely time-consuming if settlements must be re-run.

on the incentive structure of the proposal in the November 1st Order.[9] The ISO recommendation centers on a two-tiered approach, with the base tier requiring suppliers to supply a significant portion of their generation capacity under a 24-month contract to ISO load serving entities at a fixed just and reasonable rate. In the second tier, having secured low cost supply for the majority of consumers, the proposal would allow the market to function to achieve efficient market outcomes through correct incentives to investment in new generation and demand side response programs.

The ISO believes that the market outcomes in Summer 2000 clearly demonstrate that market power was exercised, and that unrestricted market-based rate authority will continue to result in prices which are not just and reasonable. The ISO proposes a mandatory supply contract for suppliers as a reasonable and necessary means to mitigate this demonstrated market power and to ensure just and reasonable rates. The mandatory contract rate represents a market power mitigation measure, not a rate which would be freely negotiated between buyers and sellers. In terms of actual implementation details of the mandatory supply contract, the ISO offers details on two possible alternatives: Option A, which establishes "safe harbor" benchmarks by types of resources; and Option B, which establishes a single rate contract.

Option A relies on a more detailed assessment of cost. Based on unit commitment patterns, it would rely on "safe harbor" benchmark prices by type of units (base-load, intermediate and peaking units). The contract requirement would be on a portfolio basis and for the entire two-year period. Based on the composition of the

[9] The proposal we offer is modeled after the "Settlement" offer submitted in this proceeding by the ISO on October 20, 2000. It differs principally in the fact that the current proposal is action-forcing on the issue of forward contracting.

portfolio and the safe harbor benchmark, the contract rate can be verified to be just and reasonable. The salient features of Option A are as follows:

- Establishment of a separate "safe harbor" benchmark price for base-load, intermediate, and peaking units.
- Bilateral contracts that, either on a portfolio or unit-specific basis, are priced at or below the applicable "safe harbor" benchmark, would be deemed just and reasonable.
- Bilateral contracts that are priced in excess of the applicable benchmarks would be subject to just and reasonable review by the Commission.
- As a condition of their market-based rate authority, in-state generators/marketers would be required to enter into forward contracts with ISO load serving entities under the above bilateral rules for at least 70% of the megawatts of generation capacity owned in California.
- An in-state generator/marketer that satisfied the above 70% requirement would be free to sell the remainder of its output at market-based rates subject, in the case of ISO-administered markets, to the applicable damage control cap which would remain at $250.
- The following in-state generation would be exempt from the "safe harbor" and bilateral contracting rules and would be free to bid, subject to the applicable damage control cap:

  (a) generation that is powered by renewable resources (e.g., wind, solar);

  (b) generation resources of 10 MW or less, provided that neither the owner nor the operator of such resources, nor any direct or indirect affiliate of the owner or operator, owns nor operates a generating unit with a nameplate capacity in excess of 10 MW;

  (c) incremental supply resources, either additions to existing units or the development of new units, located within the State of California; and

  (d) imports from out-of-state resources, but only to the extent that the imports exceed firm exports made by the owner of the supply or by any directly-or indirectly-affiliated entity.

Option B offers simplicity and certainty. Under Option B, a single rate contract would be set for a substantial portion of each generator/marketer's portfolio. The contract rate can be based on an analysis of the market and competitive market benchmark price (marginal cost of the highest cost unit needed to meet system load) calculated for Summer 2000.[10] This rate would be justified on the basis that it represents a rate which would result from a fully competitive market. It provides sufficient revenues to cover variable cost of the highest cost unit needed to serve system load and provides some contribution to fixed cost for all infra-marginal units. Additional cost recovery would be available from the 30% of output under market-based rates. Any unit not able to recover its costs would be eligible for cost-based rates but would not set the market clearing price. Again, this rate is necessary to mitigate the market power experienced in the current market place. Additional aspects of this second option are as follows:

- For each load serving entity a determination would be made of its core load requirement (the percentage of its load that serves residential and small commercial customers).

- Each generator/marketer doing business in California (both in-state and out-of-state entities[11]) would be required to make available the percentage of its portfolio necessary to satisfy the core load requirements of load serving entities at a competitive benchmark price as a 24-month contract. The percentages will be determined on a statewide basis based on the total core load and total generation capacity.

- That requirement would be satisfied by offering this contract requirement in the PX forward market. (While it is proposed to eliminate the PX buy-sell requirement, use here of the PX might facilitate California Public Utility Commission ("CPUC") willingness to waive prudence review

[10] An example of how to calculate a competitive benchmark price is given in Attachment A.

[11] For imports, the contract quantity requirement can be based on historical sales (or projected sales for a new entrant) into California.

as it now does for PX transactions, but this would have to be extended to the duration of the transactions proposed.) The offer would be available for a thirty-day period beginning January 1, 2001.

- Available generation capacity in excess of the above forward contracting obligation, or any amounts not accepted by a load serving entity during the thirty-day period, could be sold at market-based rates.

- New generation additions would be exempted from the mandatory forward contracting requirements.

- A damage control cap of $250.

Any generator/marketer would be free to reject the mandatory requirement in favor of cost-of-service rates which would apply to its entire portfolio.

Both of the ISO's proposed options would require a substantial portion of each supplier's capacity to be under fixed price contract with ISO load serving entities.[12] Based on this example, the remaining 30% of the capacity would be eligible for market-based rates subject only to a market wide damage control price cap. Other key elements common to both options include:

- Demand-side programs would not be subject to any payment cap, but would be compensated at a price that is acceptable to the ISO.

- Replacement Reserve that is dispatched to supply Energy to the market could be paid the higher of the real-time Energy price or the Capacity price (relevant to the day-ahead or the hour-ahead market in which the Replacement Reserve Capacity was purchased from the seller).

- The ISO would retain its existing authority to make Out-of-Market calls.

[12] The quantity under mandatory contract could be pre-specified monthly. For example, if a suppliers total capacity is 2000 MW and the percentage subject to a forward contract is 70%, then the maximum contract quantity for this supplier is 1400 MW. This maximum contract quantity will be the megawatt contract quantity for on-peak hours (standard 6 by 16 contracts) during summer peak months. The megawatt quantity for off-peak hours can be a third of the maximum contract quantity, or 467 MW, which can be the same for every month. For months other than the summer peak months, the on-peak contract quantity could be adjusted downward to 800 MW.

Implementation of the ISO's proposed alternative market power mitigation plan may also require modifications to ISO software in order to validate exemptions and maintain cost-based rate information. Our best current estimate is that automated implementation of this alternative may take up to two additional months beyond that required to implement the proposal in the November 1st Order.[13]

[13] While the ISO recognizes that this implementation time is slightly longer than that necessary to implement the market power mitigation proposal in the November 1st Order, the ISO believes the benefits gained by addressing the additional concerns outweighs the increased implementation time.

IV. Underscheduling

There is absolutely no disagreement that the very high level of commerce regularly being transacted in the ISO's real time market is entirely unacceptable, from both a reliability and cost mitigation standpoint. This cannot be permitted to continue. A balancing market will always be necessary to fine-tune the balance between supply and demand. But it must not be a principal commodity market for load which could have been anticipated and therefore scheduled. As the Staff Report corroborates, this is precisely what that market has become, requiring the ISO's operators to scurry in real time for as much as 20% of the capacity necessary to meet system load.

Apart from the obvious, and entirely unacceptable, reliability implications, rational purchasers in commodity markets never leave themselves exposed to significant price volatility, at least not without first exhausting all reasonable efforts to hedge that risk. Where the commodity is an essential one, and where most of the load is inelastic, the failure to hedge, through a portfolio of supply contracts of varying length, is inexcusable. Without assigning blame, this situation cannot be permitted to continue.[14] A structure must be put in place where both buyers and sellers are incented or penalized comparably; where the playing field is level.

We have concerns with the proposal in the November 1st Order for addressing underscheduling. First, it does not mandate forward contracting by supply – a necessary requirement that we already have addressed as part of our market power mitigation proposal. Second, it properly imposes a penalty for real-time deviations but

[14] We would note that in the ISO's view, the requirement of balanced schedules from Scheduling Coordinators does not contribute to the current level of underscheduling.

improperly assigns that penalty just to one side of the market, to load. The penalty must apply to both load and supply if the negotiating leverage is to remain in balance. By assigning a $100 penalty to load deviations, those on the supply side of the bilateral negotiations could well view a $250/MWh price (the penalty plus the $150 cap) as the benchmark from which to negotiate supply arrangements. Third, it addresses the need for load to preschedule, but not to forward contract.

Implementation of the excess deviation penalty[15] set forth in the November 1st Order requires modifications to the ISO's Settlements system. As calculations depend on meter data, and changes to meter data are the most common reason for settlement re-runs, a manual approach is infeasible because it is onerous under conditions where frequent settlement re-runs may materialize. Implementation time is estimated at four months from the date work commences.

Again, consistent with the underlying objectives of the November 1st Order, we offer the following as an alternative approach:

- Load serving entities be required to forward contract for no less than 85% of their anticipated requirements, at least through October 15, 2002.[16] In calculating satisfaction of this commitment, load serving entities would include capacity that they currently own. (Thus, it is appropriate to impose a somewhat reduced obligation of approximately 70% on in-state supply.)

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[15] This analysis assumes that it would be applied to deviations calculated on an hourly basis.

[16] Load serving entities have expressed understandable concern that their decisions to contract may be subject to after-the-fact prudence reviews with the possibility of disallowances. That concern has had a chilling effect on forward contracting. Recognizing the legitimate interest of the CPUC in the prudence of utility purchase commitments, we would hope that a process could be established that would satisfy the concerns of both the utilities and the CPUC – for example, granting prudence protection to forward contracts that are the result of a competitive solicitation process and are based on costs no higher than the "safe harbor" benchmark prices.

- Real-time charge assessed against both load and generation that fails to schedule 95% of actual metered consumption and supply in their final Hour-Ahead schedules. The charge would start at $10 for instructed deviations and $50 for both uninstructed deviations and Out-of-Market purchases from generators,[17] with authority in the ISO to increase either charge as shown by experience to be advisable. We would suggest a 10 MW "deadband," i.e., that no charge be assessed up to the greater of a 5% or 10 MW shortfall in scheduling.

- Disbursement of revenues from real-time energy charges to those Scheduling Coordinators that, during the trading hour in which the charges were collected, satisfied the 95% scheduling requirement, in the ratio that a qualifying Scheduling Coordinator's total schedule bears to the total schedules of all qualifying Scheduling Coordinators.

- Out-of-Market purchase costs charged to underscheduled load, adjusting for any real-time dispatch instructions.

Implementation of the ISO's proposed alternative real time trading charge would also require modifications to the ISO's Settlements system. Once again, since calculations depend on meter data, and changes to meter data are the most common reason for settlement re-runs, a manual approach is infeasible because it is onerous under conditions where frequent settlement re-runs may materialize. Implementation time is estimated at four months from date work is commenced.

V. Congestion Management Redesign, Balanced Schedules, ISO/PX Integration, and Alternative Auction Mechanisms

The November 1st Order would have the ISO complete its congestion management redesign effort under the guidance of the new Independent Board for filing by April 2, 2001. As part of that submission, the ISO will compare the zonal and nodal price models, and, should it propose continuation of a zonal approach, will include a meaningful number of zones and specify a procedure for periodic review of

[17] The ISO has potential concerns about whether applying this charge to out-of-state

established zones and of the need for their modification or supplementation. Further, the ISO will undertake, within the time period suggested, a full reappraisal of the market separation rule, of the balanced schedule requirement, and of the single price auction.

The ISO commits to a full, open evaluation of each of the above areas, building on the extensive stakeholder process that already has made substantial progress on the myriad of issues that fall within congestion management redesign, and will do so under the guidance of the new Independent Board.

In light of that commitment, it would be inappropriate to comment on the merits at this time.

VI. Locational Market Power Mitigation

One policy option identified in the Staff Report but not addressed in the November 1st Order is a recommendation that the Commission "implement locational market power mitigation measures, independent of options for price caps."[18] The problems presented by the potential exercise of locational market power were also recently described in a study by the Department of Energy:

> Electricity markets are dynamic and can change dramatically over the course of just a few hours, creating opportunities to exercise market power even though the market may be very competitive under most circumstances. For example, the geographic scope of the electricity market is determined by the transmission system. Any change in available transmission capacity can quickly alter the geographic boundaries of the market. To cite another example, certain plants may be required to run at certain times in order to meet reliability needs,

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generators may inhibit the ISO from securing these resources, if necessary, in real time.

[18] Staff Report at 6-3.

effectively giving them market power during those periods, because no other plants can act as substitutes.[19]

The ISO agrees with the concept expressed in both the Staff recommendation and the DOE paper that the issues presented by locational market power are distinct from the regional market power concerns. The ISO, therefore, offers some observations about locational market power and its mitigation, to clarify its significance within the ISO system and its relationship to the other issues addressed in the Order.

Within the ISO system, locational market power arises because of local transmission constraints, generally going into areas of dense population and hence high load. These constraints require the services of specific generation resources to ensure the reliability of the grid in these areas, and in practically all such situations there is not a workably competitive market to provide such services. As a result, the resources that are needed to ensure local reliability would be able to exercise locational market power and therefore mitigation is required.

Thus, locational market power mitigation ("LMPM") is expected to be a permanent feature of the electricity market. The Order, however, indicates that its proposed "market mitigation" measures are temporary and will be terminated at the end of a 24-month transition period (i.e., by December 31, 2002). The final order should recognize that LMPM is not a temporary measure – it will be needed indefinitely, as long as there are local transmission constraints that require the services of location-

[19] Horizontal Market Power in Restructured Electricity Markets, Office of Economic, Electricity and Natural Gas Analysis, U.S. Department of Energy, March 2000 at 2.

specific resources to ensure reliability, in areas where there is no workable competition for these services.[20]

It is also important to recognize that redesign of the ISO's congestion management procedures will not eliminate the problem of locational market power. The need for LMPM cannot be eliminated by adopting a particular design of congestion management, since congestion management cannot eliminate the underlying physical transmission constraints that give rise to locational market power. While it is true that congestion management should incorporate accurate locational price signals which will provide some incentives for new generators to locate in the constrained areas, the effectiveness of such incentives will be limited because:

- Congested areas tend to be high-density urban areas, where incremental siting costs and political barriers to new generation may be prohibitive.
- Locational market power is more a function of concentration of resource ownership within constrained areas than the absolute quantity of available capacity, so adding new capacity in the area may do nothing to reduce market power unless it is installed by a new competing supplier.
- Elimination of the constraint that drives need for local resources requires upgrading transmission, which also faces severe political barriers in most constrained areas.

Moreover, the Eastern independent system operators that have implemented alternative methods for congestion management must still rely on some form of

[20] In some areas of the grid these services will be needed continually (e.g., daily), and in other areas they may be needed periodically (e.g., seasonally, or when there are facility outages or derates).

LMPM.[21] Accordingly, the congestion management redesign proposal being developed by the ISO will include a mechanism for procuring local resources needed for local reliability, with specific measures to mitigate locational market power. In the interim, until congestion management reform can be implemented, and particularly for Spring and Summer 2001, the ISO will need to have LMPM measures in place. The ISO

[21] This practice is consistent with the approach to dispatch of reliability must-run generation by other independent system operators See, e.g., PJM Operating Agreement, Schedule 1, Section 6.

therefore seeks the Commission's guidance as to the acceptability of an ISO filing regarding this matter sometime in the first quarter of next year.

VII. <u>Miscellaneous</u>

A. The ISO is comfortable with the **additional reporting obligations** proposed for it by the November 1st Order. To the extent that the Commission elects to modify the bifurcated mitigation approach, we presume it will consider as well as modifications to the associated market monitoring and reporting functions.

B. The ISO is comfortable with the requirement that **reports of the Market Surveillance Committee and of the DMA** be filed with the Commission at the same time that they are released to the ISO Board. We assume that the filing obligation proposed in the November 1st Order is to be interpreted as preserving all justified claims of confidentiality and of privilege.

C. The ISO agrees that **interconnection procedures** are absolutely critical to the stimulation of efficient generation supply additions. The ISO will, therefore, commit to file a comprehensive interconnection policy by no later than April 2, 2001. We do, however, seek clarification as to the ability of the ISO, if it is ready to do so, to make that filing in advance of its consideration by the Independent Board. Interconnection policy has been an active subject of stakeholder consideration -- a review that is at a quite advanced stage. Draft tariff language already has been circulated to stakeholders and while we would not presume to suggest that there is a uniformity of views, it is possible that the ISO might soon conclude that additional delay is unlikely to achieve any greater level of consensus. We do, therefore, seek guidance as to the acceptability of an earlier filing, if that should seem appropriate to the current Stakeholder Board. For much the same reason, we seek similar guidance with respect to the **Long Term Grid Planning** filing.

D. We understand and agree fully with the directive that the ISO continue its efforts to jump-start **demand response initiatives** and to facilitate bidding opportunities for demand resources. While the most fertile opportunities for demand initiatives necessarily are at the retail level, dependent upon CPUC direction and support, for Summer 2001 the ISO already has committed to continuation of its Ancillary Services initiative and of its Demand Relief Program. Further, the ISO intends to introduce a program for the aggregation of small loads that are willing to volunteer for curtailment. The ISO is also mindful of the fact that the monitoring and reporting obligations that might be appropriate for participating supply-side resources, if applied in the same fashion to load, might prove as formidable obstacles to participation. The ISO, therefore, already has taken steps to reduce those burdens and will continue to explore all feasible means by which participation by load will be seen as more attractive. Freeing the ISO to negotiate with load at whatever prices are considered appropriate, an exemption from price constraints that we understand to be provided by the November 1st Order, obviously is critical to the stimulation of demand-side initiatives, as would be the assistance of the CPUC in permitting loads to participate in Ancillary Services solicitations.

E. The ISO also agrees **to the examination of market rules** necessary to ensure that sufficient supply is available to meet loads and reserve requirements. The ISO agrees with the Commission that, "Attracting sufficient supply to maintain proper reserve requirements may well benefit from the imposition of planning reserve requirements to be met from forward markets." November 1st Order, slip op. at 33. While the Commission directed the ISO and load serving entities in California to consider imposition of such rules over the next 24 months, we seek guidance as to the acceptability of an earlier filing, if the ISO and Market Participants can address that issue as part of the ISO's Comprehensive Market Redesign initiative.[22]

F. We note that the events of this past summer, as reemphasized by recent events, highlight the **need for additional capacity** in the State. During the week of November 12, approximately 11,000 MW of generating unit capacity was either forced or planned to be out of service. These outages required the ISO to declare a Stage 2 Emergency (dropping interruptible

[22] The Comprehensive Market Redesign initiative is an ongoing effort initiated by the ISO, in conjunction with stakeholders, to address numerous market reform issues, including efforts to redesign the ISO's congestion management mechanisms.

load) on three consecutive days. The ISO believes that, in order to ensure reliability and to address concerns about strategic withholding, it may be necessary: (1) to establish a reserve requirement for load serving entities, (2) to require that all existing generation satisfy certain availability standards and coordinate with the ISO on their maintenance practices and schedules; and (3) to enhance existing enforcement programs or to develop new enforcement mechanisms regarding generating unit availability. The ISO intends to address these issues in the near future.

G. While the ISO agrees that the removal of the PX Buy/Sell requirement that has been imposed on the investor-owned utilities ("IOUs") may lead to greater forward scheduling and cost mitigation, the ISO is concerned about the impact that this change might have on its **ability to monitor the markets**. If most of the IOU's energy demands are met through unreported bilateral transactions, the ISO, essentially, will only be able to monitor the "tip of the iceberg." It will be extremely difficult to explain behavior in the spot markets absent a clear understanding of trading activity in the bilateral markets. After the two-year transition period contemplated in the November 1st Order, it may be necessary to consider a requirement that the IOU's report the terms of their bilateral purchase and sale contracts, as well as the identities of their counter-parties.

VIII. Conclusion

For the reasons discussed above, the California Independent System Operator Corporation recommends that the Commission incorporate the modifications offered in these Comments in the final order to be issued in these dockets.

Respectfully submitted,

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