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Soft Price Caps and Underscheduling Penalties: How Would the FERC Plan Affect California Electricity Markets?

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Abstract

FERC proposes three short-run stabilization "remedies" in its Market Order Proposing Remedies for California Wholesale Electrics, issued November 1, 2000. The first allows the IOUs to purchase power outside the PX. The second sets a penalty that will frequently reach \$100/MWh on unscheduled power in excess of 5% of a purchaser's total load. The third is a \$150 "soft" price cap on the ISO and PX. On the infrequent occasions when the cap is effective, it will exacerbate the scheduling problem. Generally, when needed, it will be subverted by exemptions for opportunity costs. Because the soft cap is applied to the PX, but not to other scheduling coordinators, it will drive suppliers away from the PX. Allowing more forward contracting of net suppliers will reduce market power, but it will be very expensive without an effective bid cap. To be effective, a bid cap must allow no exceptions and must also be a regional cap to avoid causing reliability problems for California.

> "Never has this Commission had to address such a dramatic market meltdown as occurred in California's electricity market this summer."
> – Chairman James J. Hoecker

I. FERC's Three Central Remedies

The FERC press release lists four remedies that are proposed to take effect January 1, 2001. The first three are intended "to protect wholesale customers from unjust and unreasonable rates during the time it will take to implement longer term remedies." FERC proposes to:

1. Eliminate the requirement that the three investor-owned utilities trade through the PX.
2. Require, under threat of a \$100/MWh penalty, that market participants schedule 95% of their transactions in the "Day-Ahead or Day-of Markets."
3. Cap the PX and ISO's clearing price at \$150/MWh and allow higher bids to be paid as bid provided they pass FERC's scrutiny.

A. Forward Trading and Hedging

California has restricted the ability of its investor-owned utilities (IOUs) to purchase power through long-term forward contracts by forcing them to purchase most of their power in the PX's day-ahead market. FERC staff has noted two benefits from forward purchases: (1) they hedge spot prices, and (2) they reduce market power in the spot market. To understand these benefits it is important to consider both sides of the market.

As FERC staff notes, "holding forward contracts does not guarantee that consumers will incur lower total energy costs." (Staff Report at 5-9.) This remark concerns the demand side and is correct when, as they intend, the possible reduction in market power on the supply side is ignored. In this case, not only do forward contracts *not guarantee* lower costs, they have a 50% chance of raising costs. All that is gained by forward contracting is a reduction in risk. Forward prices are just as high on average as spot prices. (In the West, forward purchases saved money because this summer was hotter than expected. In the East, forward purchases wasted money because the summer was surprisingly cool.)

The FERC staff also makes an important point regarding the effect of forward contracts on market power.

> Thus, to the extent that the majority of its supply portfolio is committed under [forward] contracts for differences, the generator's incentive to exercise market power in the spot market will be reduced or even eliminated. (Staff Report at 5-9.)

For long-term forwards this is correct, but short-term forwards require consideration of the impact of spot prices on forward prices. For very short-term forwards this effect dominates and prevents the reduction in market power. A supplier whose current portfolio (today's deliveries) has been sold forward will most likely be in the process of selling forward a similar portfolio of future deliveries. She knows that the price fetched by these forwards is the expected future spot price and that this expectation is based partly on current spot prices. Exercising market power in the spot market raises the price of forward contracts being sold today and in the near future. For a supplier selling short-term forwards, the incentive to raise the spot price (exercise market power) is almost as strong as the incentive for a pure spot trader. But for very long-term forwards, the staff's point is exactly correct.

While increased forward trading is desirable for both reasons mentioned by the staff, the possibility of reducing market power is by far the more important because reducing consumer risk does not reduce consumer cost. Reduction in market power is crucial and could provide real relief to consumers. To be sure forwards will have a strong impact on market power, net generators must sell a significant amount of their power (more than half) through relatively long-term contracts.

B. Ninety-Five Percent Scheduling

The Commission summarizes its finding on this point as follows: "Underscheduling puts system reliability at risk and creates a stronger sellers' market and higher prices as real time approaches." (Order at 23.) The staff notes correctly that "In sum, underscheduling had no clear impact on this summer's prices."(Staff Report at 5-14.)

The proposed penalty is the real-time price or $100/MWh, whichever is less. Because underscheduling is most common in conditions of high demand when the price is likely to be near or above $100/MWh, this analysis will simply treat it as a $100/MWh penalty.

C. The $150 Soft Cap

The Order states (p. 34) that "the supplier receiving $160/MWh [or any price over $150] would be required to report that bid to the Commission and provide certain cost information to the Commission." This information would include

> the name of the seller, the price and amount of MWs covered by the transaction, the hour(s) covered by the transaction and the incremental generation cost. The filing may also identify legitimate **opportunity** costs. (Emphasis added.) (Order at 35.)

The Commission goes on to state

> These data will be used to monitor prices on a more current basis, in order to detect potential exercises of market power or otherwise non-competitive market prices and to adjust transaction prices, if necessary, to establish just and reasonable rates." (Order at 36.)

Bids below $150 will be cleared in the usual manner at a single price, but bids over $150 will be paid their bid price subject to possible future adjustment by FERC. This pay-as-bid feature is central to FERC's conception of how to reduce California's prices to a just and reasonable level.

Pay-As-Bid Auctions. The Order reaches the following conclusion about the current single-price auction in order to support a change to a partial pay-as-bid system.

> A significant factor causing high prices in California was the fact that every MW in the market is priced at the market clearing price. (Order at 34.)

Normally, this is how competitive markets work. All trade takes place at, or very close to, the clearing price, with some errors in both directions.[1] One surprising result of auction theory is that an auction for a single commodity will have exactly the same cost on average whether bidders are paid their bids or paid the highest losing bid. Klemperer calls this "auction theory's most celebrated

[1] The opening price of every stock on the NY Stock Exchange is a market-clearing price that is used to clear every available trade that has accumulated over night. PJM and the NY ISO also price all trades at the market-clearing price.

theorem."[2] The "revenue equivalence theorem" is much broader than the special case just stated and undoubtedly applies quite accurately to the pay-as-bid and single-price auctions under consideration.[3]

The Commission's central concern deserves attention, "why should a supplier who bid a lower figure receive the same value as that afforded to the supplier of [the] higher-priced increment?"[4] Low bidders should be paid the market clearing price so they will continue to submit bids that reflect their true marginal costs. If they are penalized for bidding true costs, they will immediately begin submitting bids very close to the market clearing price. This observation is at the heart of the revenue equivalence theorem and is recognized by the FERC staff which correctly concludes, "In sum, it is not clear whether a pay-as-bid rule would have the effect of lowering consumers' bills." (Staff Report at 5-16.)

Pay-as-bid auctions force suppliers to guess the clearing price. When suppliers do not know the market clearing price and are forced to guess rather than bid their own costs (which they know well) they make mistakes in bidding. The result is the auction selects the wrong suppliers, and the cost of power is increased. This, too, is predicted by auction theory.

Cost-of-Service Regulation. Although FERC argues that switching to pay-as-bid will hold prices down, it does not rely on this prediction but instead intends to review every bid over $150 and "adjust transaction prices, if necessary." The Order's explanation of the "adjustment" consists of the following:

> we expect to see bids above $150 under some market conditions. We intend here to monitor these bids, not to prohibit them. We also fully appreciate that high cost suppliers will bid a margin above their variable costs as a needed contribution to their fixed costs. The Staff Report concludes that at times of peak demand running costs can be in the range of $160 to $200/MWh for some units. Staff Report at 3-21 and 5-3. In addition, the PX report (at page 30) on price activity May/July 2000 indicates that variable costs during peak periods can approach $500/MWh for some units. (Order at 35.)

Bidding "a margin above their variable cost as a needed contribution to their fixed costs" will prove difficult to interpret and add uncertainty to the market. When this rule is applied on a year-round basis, it is called cost-of-service regulation.

The Demise of the PX? Capping supply bids in the PX while allowing the IOUs to leave may well lead to its early demise. This could mean there would no longer be a transparent day-ahead market in California.

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2 "Why Every Economist Should Learn Some Auction Theory," Paul Klemperer, July, 2000. http://hicks.nuff.ox.ac.uk/users/klemperer/papers.html

3 An example demonstrating both why pay-as-bid causes high bids and can produce costs that are even higher than a single-price auction is available at www.stoft.com.

4 Commissioner Hébert, concurring with Order, page 5. One might equally well ask why a demander who bid a higher figure should pay the same price as that paid by the demander who bid the clearing price. Power is worth more to the former than to the latter, yet no one proposes making them pay as bid.

II. Two Contradictions within the FERC Remedies

A. The Price-Cap vs. the 95% Scheduling Rule

The staff correctly points out that, even though its cap is set at $2500/MWh, the PX market acts as if it were capped at $250 because it is arbitraged with the lower-capped ISO market.

> The PX's higher energy price cap has not limited energy prices in the PX. Instead ... the ISO's cap has effectively limited the price of generation sales in the PX day-ahead and hour-ahead energy markets. Buyers never offer to pay more in the PX market than the ISO's maximum purchase price, since they may still buy at the ISO's cap in the real-time market if their bids are not accepted in the PX. (Staff Report at 5-12.)

FERC has not capped all of the energy markets, and it has tried to keep load out of the market that has been used for protection in the past. In order for the new cap to work, load must be able to trade in a capped market. The PX is one such market but there is no assurance load can trade there. In fact, when prices are high, it will need to take refuge in the real-time ISO market. This conflicts with FERC' scheduling rule as is shown in the following analysis.

This analysis includes three markets, (1) the real-time ISO market, (2) the PX market, and (3) the unregulated day-ahead markets (non-PX scheduling coordinators). Call these the ISO, the PX and the UPXs, the later standing for unregulated power exchanges.

The PX vs. the UPXs. As one might guess, having FERC-regulated supply bids is not an advantage for the PX in its competition with the UPXs.[5] Although FERC states (Order at 22) that "As an independent exchange, the PX will be free to design and offer the services needed by market participants," a few pages later (Order at 34) it proposes that "for all short-term markets operated by the PX ... the single price auctions be used for all sale offers at or below $150. .... suppliers who choose to bid above $150 will be paid their as-bid price." These bids along with supplier cost information must be reported to FERC so it can "adjust transaction prices, if necessary, to establish just and reasonable rates." Apparently the services that the PX is free to design do not include an energy market.

The result is not hard to predict. Generators will wish to minimize the trading they do in the price-capped markets, while loads will want to maximize such trading. Loads can force trading into the ISO by procrastinating, but they cannot force trading into the PX.

Generators will prefer that when price-capped trades do take place in a regulated market they take place in the ISO market rather than the PX. They will want loads to reach their 5% limit as quickly as possible so that the FERC scheduling penalty will take effect. By refusing to trade in the PX, the generators insure that once 5% has been traded in a price-capped market, any further price-capped trading will be penalized by FERC at $100/MWh. This will help prevent load from escaping to the price-capped market.

In conclusion, during times in which the price-cap is binding, it will cause generators to avoid the PX in favor of UPXs. Consequently the only way load can take advantage of the price cap is to postpone trading until the real-time ISO market. Currently this is a major motivation for unscheduled trading, and it will remain as such.

[5] In the past, the PX and the other scheduling coordinators have been treated in an even-handed manner, except for the requirement that IOUs use the PX. This FERC Order now places the PX at a decided disadvantage.

The ISO vs. the UPXs. When the WSCC price is below $150 the soft cap makes no difference. When it is above $150 then all generators are free to bid that price because it is their opportunity cost. This implies the cap is only effective in the following special case. If the price in the external market is low and the lines into the ISO are congested, then the ISO price could be above $150 while the external price is below $150. A second reason to analyze the no-opportunity-cost case is that FERC may be tempted to drop the opportunity cost in order to rehabilitate the soft cap. So first consider the unlikely case in which the soft cap is somewhat effective.

In this case, there is tension between FERC's two goals, low prices and full scheduling. FERC and the ISO would like to keep energy trading out of the real-time ISO market. But if this happened, the generators would force trading into the UPXs and the market would be without a cap. Loads would like to force trading into the ISO and thus under FERC's protective cap. As the ISO's Department of Market Analysis (DMA) states,

> the ability of buyers to limit the prices they are willing to pay in the forward energy markets and to shift demand into the real time imbalance market represents one of the major ways that large buyers can limit overall costs and defend against market power.[6]

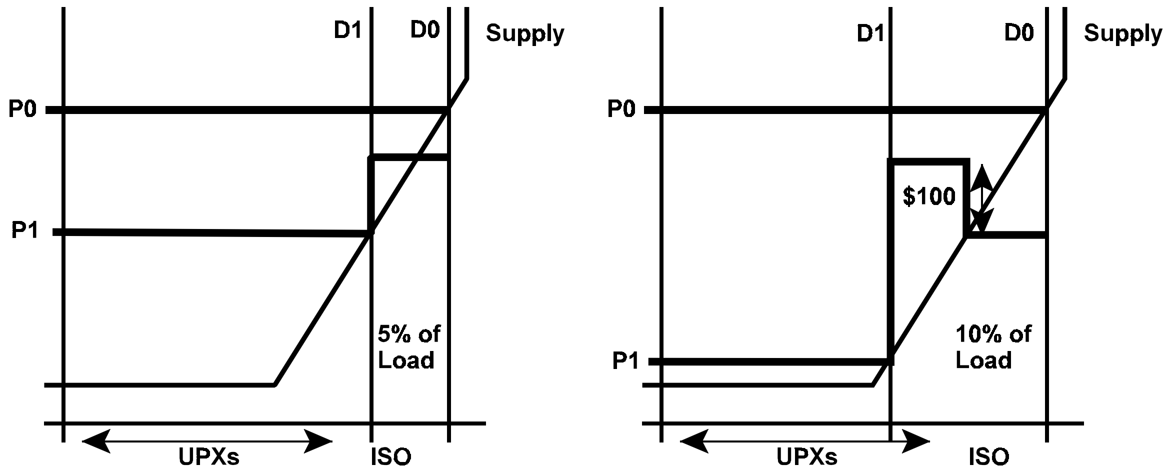
To analyze the outcome of this tension requires a model of suppliers and of FERC's soft-cap policy. The correct model must be complex and is presently unknown. FERC has stated that it will allow bids that are above marginal cost. According to the ISO's DMA, generation supply curves are also above marginal cost in the high-demand region. For simplicity the generator's supply curve and FERC's allowed bids are modeled as identical. Figure 1 shows this combined curve labeled as "supply." Vertical line D0 is total demand. Vertical line D1 is demand remaining in the UPXs after some demand has shifted into the ISO. The gap between D0 and D1 indicates the amount of demand in the ISO market. The region of the supply curve between the two demand curves is the part of supply that will be bid into the ISO market. Load in the ISO will be charged the average price of the bids. This is shown by the dark horizontal line through the middle of this supply segment in the left graph. Load in the UPXs will be charged the market-clearing price which has now been reduced to P1 by the withdrawal of demand.

Clearly the transfer of load out of the unregulated PXs and into the price-capped ISO is advantageous to load and must be expected at least up to the 5% level. Assume now that D1 in the left graph is at the level where 5% of load is being left unscheduled. Will load continue its migration to the ISO, or will it stop here as FERC and the ISO desire? The right half of Figure 1 shows what happens when the unscheduled load is increased to 10%. The $100 penalty provides some disincentive but is too small in this instance to prevent the continued shifting of load into the ISO. This seems quite plausible, given that $100 is approximately the current penalty imposed on loads to cover replacement reserves, and it has not stopped migration to the ISO. In fact, there is a new and important force behind this migration. As load migrates to the ISO, more generation falls under the cap and the additional generation has lower FERC-allowed bids. This causes a decline in the average bid price and a reduction in the ISO price to loads. This reduction may be great enough to pay loads for the $100 penalty they incur before the reduction in the UPX price is taken into account.

Barring other problems with the soft cap, this analysis would be accurate if FERC capped bids at marginal cost and suppliers did not exercise market power. Unfortunately it is very difficult to

[6] "Report on California Energy Market Issues and Performance: May-June, 2000." August 10, 2000.

Figure 1. Why Loads Wait for the Real-Time ISO Market



model market power in this environment, and little is known about how FERC's soft bid cap will work. Nonetheless, this approach gets the major effects qualitatively right. Moving load from the UPXs to the ISO definitely will lower price in both markets. This is the unusual feature of FERC's soft cap. Increasing demand in the ISO market lowers the price paid by demanders—just the reverse of a normal market. This is the feature that increases the force driving load into the real-time market relative to the present situation. Given this, it seems likely that the $100 scheduling penalty will be no more effective than the current replacement-reserves charge.

But the soft cap probably will face more serious problems. It appears possible to circumvent it within California, and the external market presents an additional challenge. First consider the internal gaming possibilities. Wholesale marketers can sell power to the ISO and because their cost is whatever they paid for it, they are exempt from the price cap. FERC has no practical way of tracing these sales back to the actual suppliers. But even if they did, sales to marketers are not capped. Consequently, even low cost generators should be able to circumvent the price-cap whenever the cap is binding without the aid of high external prices.[7] Consequently the cap should fail even under the unusually propitious circumstances just discussed.

B. The Price-Cap Meets the External Markets

California relies heavily on imports from the external markets that surround it. When the price in these markets is high, California generators can export over transmission lines that are unlikely to be congested in the outbound direction. That makes their opportunity cost high for selling into the California market.

> In the final week of June, bilateral prices rose to their highest levels to date as Bonneville Power Administration and the Northwest utilities outbid California and the Southwest, reportedly paying as much as $1,400/MWh to buy power in hourly bilateral markets. (Staff Report at 3-9.)

[7] This point is based on a private communication from Paul Joskow in which he remarks: Any California generator can easily bypass the cap by trading through a series of wholesale marketers even if the power is eventually sold back to the PX or ISO. There is no practical way for FERC to trace third party sales back to the costs of the actual supplier of the power. A marketer selling to the PX and ISO need only show that "it paid a lot for the power." Whenever the cap would be really binding the power will get daisy-chained from generators through marketers.

FERC has noted the importance of taking account of opportunity costs when evaluating bids under its bid-cap. If bids are given full credit for such costs, this should prevent severe arbitrage problems that would accompany a rigid price cap on the California markets alone. But this also means California will be left without any cap whenever the external market is as tight or tighter than the internal market.[8]

C. Conclusions on the Two Contradictions

FERC has tried to solve two important problems: underscheduling and excessively high prices. Unfortunately the two remedies conflict. Because the PX market can and will be avoided during tight market conditions, the crucial bid cap is on the real-time market. But this can be effective only if load is free to take shelter under this cap, something it can do only by underscheduling.

If the price-cap ever did work, it would lead to underscheduling because load would seek shelter in the real-time market, the only place it could take advantage of the cap. When the external market is tight, the bid-cap should fail but the underscheduling penalty should work.

III. Resolving the Price-Cap Dilemma

California has many flaws in its market rules and some in its market architecture, but the problems that caused the "market meltdown" are well known and more fundamental. There is a shortage of generation and essentially zero demand elasticity. The two in conjunction cause very high prices due to scarcity and market power.

High prices are important for attracting investment in generation but only up to a point. It is not necessary to accept arbitrarily high profits on 40 GW of existing generators in order to attract 5 GW of new generation. It is also not desirable to accept large transfers of wealth through market power. FERC has recognized this and concluded that some form of price cap is needed. It has recognized as well most of the difficulties that price caps present and has attempted to avoid them, but it has not fully succeeded.

Prices serve a number of functions in both the short and long run which should not be compromised by a cap, and a cap should not introduce new problems. Specifically, a cap should not:

1. eliminate the investment incentive.
2. prevent high-marginal-cost units from running.
3. encourage the export of power to external markets during a shortage.
4. move trading into the real-time market and thereby cause underscheduling.
5. be too complex in administration.

But a cap should:

6. hold the price down.
7. suppress attempts to exercise market power.

The present proposal satisfies 1, 2 and 3, fails on 4, 5, 6, and 7. These failures have a single cause. When two markets are closely tied, it is impossible to price cap one effectively but not the other

[8] "However, should we find it necessary to order refunds, we will limit refund liability to no lower than the seller's marginal costs or legitimate and verifiable **opportunity costs**." (Emphasis added.) (Order at 39.)

without causing severe problems with arbitrage. The FERC proposal becomes ineffective whenever it would cause such problems. There is a more straightforward and effective approach, and FERC has already applied it in the Eastern Interconnection.

A. FERC's Precedent on Regional Caps

FERC understands well the need for price-cap coordination between neighboring control areas as explained in its Order of July 26 setting a temporary $1000 bid cap.

> Our decision to approve the bid cap at the level of $1,000 in the New England energy market is also influenced by our concerns about coordination with neighboring control areas during periods of mutual capacity deficiency or emergencies. **Different bid caps in neighboring control areas could create supply problems. A single cap across major trading regions** would limit incentives to sell into a higher price region during capacity shortages that affect several regions simultaneously. The $1,000 per MWh bid cap that we accept here for New England is at the same level as the cap that is currently in effect in PJM and that we are approving concurrently in an order for the New York ISO. (FERC Order, July 26, 2000, Docket No. EL00-83-000, et al., page 20. (Emphasis added.)

Having a $150 bid cap next to an un-capped market is far more problematic than having discrepant bid caps at the $1000-plus level. This may explain why FERC has arranged for California's bid cap to become non-functional whenever prices rise above $150 in the external markets. But it is not necessary to vitiate the bid-cap's effectiveness whenever it is most needed provided FERC follows its own advice and implements a regional cap.

B. The Proposed Regional Purchase-Price Cap

Such a cap would look much like the current ISO bid cap but it would be extended to purchases by all FERC-regulated system operators in the WSCC. It might be near $250/MWh. Because real-time scheduling is undesirable, there should be a penalty of the type proposed by FERC on unscheduled load. This might amount to $50 or possibly much less and should reflect the cost of unscheduled load. This lower value should work because it would not have to contend with as many countervailing forces as under the present system or under FERC's proposed remedies.[9]

With a $50 real-time penalty, prices in the PX and UPXs should be almost $50 higher than in the ISO's real-time market. (The real-time price cap could be adjusted downward to compensate for this.) This penalty should keep loads and generators trading in the PX and UPXs.

As FERC correctly notes, the cap must not be so low as to deter investment. It then explains that:

> A combined-cycle generating unit with a heat rate of 10,000 BTU/KWh will incur fuel costs of $50/MWh, and NOx emission costs of $40/MWh. The remaining $60/MWh will permit an investment payback of 5 years if the unit is selected for dispatch at the $150 level about one-third of the time (i.e. 8 hours per day). (Order at 37.)

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[9] It would not contend with (1) FERC's soft cap that rewards load with increasing lower prices as it continues to migrate to real time; (2) double payment for replacement reserves; (3) out-of-market purchase at above-the-cap prices; and (4) above-the-cap external prices.

This is the wrong calculation for the purpose of setting the level of a price cap. Power markets need to support the full spectrum of technology from base-load plants to peakers in order to provide an efficient mix of generating plants. The type of plant that needs the highest prices (for the few hours it runs) is the peaker. FERC seems not to have taken this into account when setting the $150 level for the soft cap. The regional cap should be set high enough to cover both the variable and fixed costs of a new peaker during the hours that the market price is above its variable cost.

Existing plants present a different problem. The cap must be high enough to cover their variable costs; otherwise they will not run. Unfortunately, there will be old inefficient plants with extremely high variable costs. These need not set the price for the entire market but can be handled much like the exceptions allowed under FERC's soft cap. The key simplification is that *there are no opportunity costs with a regional cap* because no higher price can be obtained in any other market. Because it is important that these plants run, some excess above variable cost should be covered to prevent an inadvertently low individual cap from driving them from the market. But, from an efficiency point of view, there is no need to cover their fixed costs. Those costs are sunk, and these plants will run without such payments.[10] More importantly, plants with costs below those of a new peaker will not become frequent and complex exceptions to the price cap anytime there are high prices around the WSCC.

Let us now test such a regional cap against each of the above criteria.

1. Investment. Both the regional and the soft cap can be set to induce new investment.

2. High-Marginal-Cost Units. Both caps will need to make exceptions for these, but this is simpler with a regional cap because there are no opportunity costs higher than the cap.

3. Exports. Both caps solve the problem of exporting reliability reserves whenever the external price is above the California price. The regional cap solves it by holding down the external price. The soft cap solves it by allowing the California price to float up to the external price.

4. Scheduling. A regional cap does not encourage load to drive down the price it is charged by purchasing more in the real-time market. This is only a problem with the average-cost pricing associated with the soft cap. Only such a soft cap exacerbates the underscheduling problem.

5. Complexity. Under the regional cap, the only exceptions are a few extreme plants with variable costs greater than the combined fixed-plus-variable cost level of a new peaker. Under the soft cap every plant in California is a potential exception whenever the external markets have prices above $150.

6. Holding the Price Down. On this point there is no comparison. The soft cap ceases to function as soon as external prices are higher than $150/MWh. In other words, there is simply no cap when it is needed most.

7. Market Power. Market power does the most damage to reliability and price during an area-wide shortage. It is exercised by withholding output, and at such times systems are most willing to

[10] From a fairness point of view, it should be noted that most of these are old and, especially after this last summer, their sunk costs have long-since been recovered. In any case, their treatment under a regional cap will be simpler than under FERC's soft cap.

pay exorbitant prices.[11] The regional cap takes away market power during an area-wide shortage, while the soft cap ceases to function. Under a regional cap, once prices hit the cap, the price can be driven no higher by market power. So it pays generators to sell all they can at that price. Thus, with a regional cap, generators will bid their full capacity at the cap. With the soft cap there is no price at which it pays generators to stop withholding. This is a significant threat to reliability.

C. Questions of Implementation

Several questions have been raised concerning the feasability of a regional cap as well at the possibility of making any cap stick in the face of pressures for the ISO to "pay whatever it takes" when supplies are short.

FERC's Lack of Region-Wide Jurisdiction. FERC cannot impose a cap on Canada, Mexico, the municipal utilities, or on other government agencies. Several of these are net suppliers. So jurisdiction is not an issue in these cases because the point of a regional cap is to prevent a net buyer from paying a higher price and taking power away from the bid-capped region. An un-capped net demander could still cause a problem. Any problem, however, would be much smaller if the 85% of the demand (under FERC's jurisdiction) is capped and 15% is not than if only 30% (California ISO) is capped and 70% (the rest of the WSCC) is not.[12] Imposing a regional cap reduces the inter-market arbitrage problem dramatically, but it does not eliminate it completely. In addition, uncapped regions, for example LADWP, may recognized that it is in their interest to follow suit rather than opening themselves up to market power by offering to pay more.

FERC's Inability to Cap Private Day-Ahead Markets. By capping the purchase price of system operators in the real-time market, all forward markets are indirectly capped as well. If the cap price is $250 (and the real-time penalty is $50) there is simply no reason for load to pay $301 in the day-ahead market when it can purchase for $300 in real time. It would gain nothing because scheduling a day in advance provides no privileges in the real-time market. (Also note that load will not be forced into the real-time market because it is willing to pay up to $300 in the day-ahead market. This is $50 more than generation can get in real time, so generation will make sure trades happen before the real-time market. So the effective cap is $300.)

Out-of-Market Purchases and Reliability. Most of California's reliability problems this past summer may have been caused by market power. This has not been established but is a plausible theory. When reliability is endangered by the market, it should be considered in any market redesign. As long as there is room for market power, there is an incentive to withhold generation. A firm price cap removes any incentive to withhold to the extent that would of cause a reliability problem.

Say the reserve requirement is 5% and enough is withheld to bring the reserve margin down to 4%. At this point the ISO offers to pay the price cap. Now generators have no motive to withhold any more because withholding cannot drive the price higher. Suppliers will actually want to sell a bit more until the margin increases to 5% and there is a chance of the price falling. If the system gets genuinely tight, so there simply is not enough generation to keep reserves at 5%, then generators will just sell everything they can produce at the price cap. So, in a real shortage, nothing is withheld.

[11] One unpublished study indicates that last summer's emergencies were in fact caused by output being withheld in order to push the price still higher. And, of course, profit maximizing generators should be doing this.

[12] These are extremely rough figures intended only to illustrate the point.

The reverse is true if there is a way to circumvent the cap. For example, if the ISO is known to make out-of-market purchases at prices above the cap, it can make sense for generators to withhold until a high level emergency is in effect in order to sell at the highest possible price. Because there will be political pressures on the ISO to "pay whatever is needed," this type of market-power-induced reliability problem can only be effectively prevented by a FERC order. This will be credible to suppliers, and they will choose to sell all they can at the price cap rather then earn less in a vain effort to raise the price above it.

There has been some question of generators withholding to the point of causing load-shedding in the face of a firm cap. As just noted, this would reduce their profits and fail to raise the market price. This behavior fails the standard definition of market power on both counts. Suppliers' only motive for withholding to this extent would be to force FERC to rescind its order. Such behavior seems extremely unlikely, so one can be quite sure the cap would stop withholding before it threatens reliability, provided there are no loopholes.

Impact of the Cap Outside the CA-ISO. It might be thought that capping external markets because of California's problems is unfair. But it is more likely that a regional cap will protect external markets from the ill effects of California's market problems. When power is withheld in California, it not only raises the price in California, but this price attracts replacement power from surrounding markets and that raises the external market price. Without a regional cap, California's problems will be exported.

D. Summary

A nearly-hard interconnection-wide cap would have the following advantages over the soft-cap proposal: (1) increased reliability; (2) savings to consumers; (3) less interference with the market, and (4) less regulatory burden on FERC.

IV. Conclusions and Recommendation

The proposed remedies will neither accomplish FERC's goals nor stabilize California's electricity market.

1. Allowing the IOUs to leave the PX may encourage long-term forward contracts with net generators. If so, this is important because it will reduce market power.
2. These contracts will allow the net generators to capture much of what they could expect to gain through exercising their market power. Because the soft cap will have little if any effect, these contracts should be quite expensive.
3. The real-time scheduling penalty should be effective because the soft cap will generally be ineffective. If the soft cap could be made effective by eliminating the opportunity cost exemption, it would subvert the scheduling penalty by inducing load to seek the shelter of the real-time market.
4. California needs an effective price cap that does not exacerbate its reliability problems. Only FERC can provide this because only FERC can impose a regional cap.