Analysis of "Order Proposing Remedies for California Wholesale Electric Markets (Issued November 1, 2000)"

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EXECUTIVE SUMMARY

In its analysis of the Federal Energy Regulatory Commission (FERC) "Order Proposing Remedies for California Wholesale Electric Markets", the Market Surveillance Committee (MSC) of the California Independent System Operator (ISO) reviews the market-power remedies in the Proposed Order and suggests alternative approaches for consideration that, in the MSC's view, will be more effective in constraining market power. The Proposed Order's remedies are as follows:

1. **PX Must-Buy**: Eliminate the requirement that the three investor-owned utilities (IOUs) – Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) – must sell into and buy from the California Power Exchange (PX);

2. **Real-time Penalty**: Require, subject to a $100/MWh penalty, that all market participants schedule 95% of their energy consumed in the day-ahead and day-of markets.

3. **Soft-Cap**: Implement a $150/MWh "soft-cap" on bids that set the market-clearing price in the PX and ISO, and pay as-bid (subject to FERC review and potential refund) for PX and ISO bids above $150/MWh.

4. **Refunds**: Imposing a 24-month potential refund obligation on sellers into the PX and ISO markets.

There are other proposed remedies but they have not been fully developed at this time.

The MSC concludes in its analysis that the Proposed Order's remedies are likely to be ineffective to constrain market power and, in fact, could exacerbate California's supply shortfalls and, thereby, increase wholesale energy prices. The basis for this conclusion is as follows:

The elimination of the requirement that the IOUs must purchase all forward energy from the PX, when combined a $150/MWh soft-cap that applies only to sales to the ISO and PX, but not to other purchases, allows sellers at any time to evade the cap by diverting sales from the ISO and PX to other, uncapped markets. Even if the cap could not be evaded by selling into uncapped markets, the opportunity cost and the undefined cost-based rate exceptions to the cap threaten to render it ineffective.

Though ineffective, the Proposed Order's remedies, if implemented, are likely to exacerbate supply problems in California because of uncertainty as to whether and how the Commission's refund policy will be carried out. In times of tight supply margins in the WSCC market, generators and marketers will sell into markets that are not subject to a refund condition, rather than selling into markets that are. The imprecision of the Commission's refund policy is likely to make this worse.

The Commission proposes an under-scheduling penalty applicable only to loads and not to generation. While the proposal could provide incentives to load not to under-schedule, it is also likely to be factored into seller bidding behavior into the PX. Sellers may have perverse incentives to increase their bids into the PX to reflect the penalty buyers face if they purchase in the ISO real-time market. The result is likely to be higher PX prices without any necessary reduction in under-scheduling.

The MSC analysis suggests an alternative mechanism which, in its view, will more effectively mitigate market power, curtail under-scheduling and ensure adequacy of supply to the California market. Under our proposed alternative

(1) The PX "must-buy" requirement would become a "must-schedule" requirement. IOUs would be required to schedule all forward energy through the PX, but would be free to purchase it from any source.

(2) California generators and entities that sell to any California purchaser (not limited to the PX and ISO) could continue to be eligible for market-based rates (and would be free of refund obligations) only if they offer a substantial portion of their sales in the form of two-year contracts at rates that approximate competitive prices. The details of such a proposal are outlined in this report. The volume offered by sellers, in the aggregate, would be sufficient to cover the all three IOUs' residential and small commercial customer load using an average load profile for weekdays and weekends for each month.

(3) Any market participant that does not offer these two-year market-power-mitigation forward contracts would be subject to cost-of-service rates for all of their sales of energy and ancillary services into the California market for at least the two-year market power mitigation period.

(4) The CPUC would be encouraged to set a default rate for IOU residential and small commercial customers based on projected wholesale energy costs under the 2-year contracts described above.

(5) The under-scheduling penalty should be even-handed. The MSC recommends a real-time trading charge that is applicable both to load and generation and, more important, does not distinguish between instructed and uninstructed deviations from schedule.

Introduction

This document provides an analysis of the November 1, 2000 "Order Proposing Remedies for California Wholesale Electricity Markets" (henceforth referred to as "Proposed Order"). Our analysis concludes that the proposed market remedies will be ineffective at protecting the California market against exercise the of market power. During many hours, they may in fact increase the ability of generation unit owners to increase wholesale prices in the California market and, in general, will most likely exacerbate California's tight electricity supply conditions. Consequently, we advise against implementing these market rule changes in their proposed form. Although we can see advantages to independent boards of directors for the California Independent System Operator (ISO) and Power Exchange (PX), we do not believe that a stakeholder board of directors is a major cause of the perturbations in California's energy and ancillary services markets.

The Proposed Order provides little additional protection for California consumers from the exercise of substantial market power that has been documented in a number of Market Surveillance Committee (MSC) Reports during the 28 months that the market has operated[1]. The Proposed Order also states that the Federal Energy Regulatory Commission (FERC) will take whatever steps it is able, "to make markets in the region work for the ultimate benefit of consumers—assuring a reliable supply of energy at the lowest reasonable rate." For this reason, a major portion of our comments is devoted to outlining a market power mitigation mechanism that we recommend the Commission implement to protect California's residential and small

[1] "Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO)," August 19, 1998; "Report on the Redesign of the Markets for Ancillary Services and Real-Time Energy, March 25, 1999; "Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets, October 18, 1999; and "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000.

business consumers from this exercise of market power over the next two years. This mechanism requires all entities that have sold energy or ancillary services into California since the market began to provide a forward contract for a substantial fraction of their annual energy and ancillary services sales at a price that is deemed just and reasonable by the FERC. We outline a recommended methodology for determining the magnitude of this “substantial fraction” of annual sales for each entity and a methodology to determine the “just and reasonable rate” for these forward contract sales. These forward contracts should then be made available for purchase by load-serving entities in California in proportion to the amount of residential and small business load they serve, as determined by the California Public Utilities Commission (CPUC). This will allow the CPUC to set a fixed retail rate for these two customer classes for the two-year period covered by these forward contracts. This FERC/CPUC-coordinated market power mitigation plan will lock-in guaranteed protection for California’s small business and residential electricity consumers from market power in the state’s wholesale energy market over this time period.

The following section of this report outlines the main features of FERC’s proposed remedies and highlights the major problems with each proposal. This is followed by our alternative proposal to protect small business and residential consumers from substantial spot market power over the next two years, yet preserve the maximum incentives for new generation entry.

FERC's Proposed Remedies

The major proposed remedies are:

1. Eliminate the requirement that the three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—must sell into and buy from the California Power Exchange (PX.);
2. Require, subject to a $100/MWh penalty, that all market participants schedule 95% of their energy consumed in the day-ahead and day-of markets.
3. Implement a $150/MWh cap on bids that set the market-clearing price in the PX and ISO, and pay as-bid (subject to FERC review and potential refund) for bids above $150/MWh.
4. Impose a 24-month potential refund obligation on sellers into the PX and ISO markets.

There are other proposed remedies but they have not been fully developed at this time. For example, the Proposed Order appears to advocate removing the current market separation rule, but it offers no specific alternative in its place. It also states that units that win in the Replacement Reserve market can be paid to provide Replacement Reserve or energy, but not both. Our market power mitigation plan proposes an alternative to the Proposed Order's recommendation on this issue that, in our view, would provide strong incentives for both generation unit owners and load-serving entities to more accurately forward-schedule.

There are a number of problems with each of the major proposals that we detail below. As we discuss below, the combination of the first three recommendations could significantly worsen the current under-scheduling problems and continue to produce unjust and unreasonable wholesale energy and ancillary services prices to must be paid by California consumers. In contrast, the market power mitigation plan we recommend would lock-in protection from the exercise of market power for residential and small business consumers and provide strong incentives for accurate scheduling of load and generation.

End of PX Buy/Sell Requirement

The Proposed Order recommends eliminating the requirement that the California IOUs sell into and buy from the PX. Unless it is accompanied by several other market rule changes recommended in previous MSC Reports, the most likely result of eliminating the PX Buy/Sell requirement and imposing the $150/MWh "soft-cap" recommended in the Proposed Order is that the PX will lose significant volume and incur additional costs. There is also likely to be little if any change in a seller's ability to exercise market power in the California market. Sellers that wish to avoid the potential complication of the "soft cap" still have the option to make bilateral sales through the many other Scheduling Coordinators other than the PX or make sales outside of California entirely.

As emphasized in previous MSC Reports (in the most detail in the October 1999 Report), the requirement that all of California's IOUs sell into and buy from the PX does not significantly hinder the efficiency of the California market. Instead, restrictions on the quantity of forward contracts, the identity on the counter-party to the contract, the types of forward contracts purchased, and the markets used to purchase forward contracts by California's IOUs are the underlying source of the market inefficiency, not the .PX Buy/Sell requirement as such. As has been emphasized in all previous MSC Reports, by allowing all of load-serving entities complete flexibility in their forward energy and ancillary services procurement decisions, gives them the greatest ability to avoid the attempts of generation unit owners to exercise market power in the California energy and ancillary services market. The October 1999 and September 2000 MSC Reports described a wide array of potential forward contracting mechanisms for load-serving entities to use to hedge themselves against spot market price volatility. Examples were given of both one-sided and two-sided contracts-for-differences. These forward financial contract forms are actively traded in all electricity markets around the world. There are also many other potential forward contracting vehicles that can be individually negotiated between load-serving entities and generation unit owners to manage residual wholesale price risk that is unique to each load-serving entity.

Giving load-serving entities complete flexibility to forward contract does not automatically imply they will use this to flexibility procure energy and ancillary services in a least-cost manner. Unless load-serving entities are provided with strong incentives to procure energy and ancillary services in a least-cost manner, this additional flexibility in forward contracting will not ultimately benefit California consumers. The September 2000 MSC Report proposed two mechanisms for providing these incentives to load-serving entities in California. The recommended mechanism is to implement retail competition in electricity supply as soon as possible. Under this scheme competition among load-serving entities, including the three California IOUs, to attract retail customers would provide extremely strong incentives for all of these entities to procure their wholesale energy at least-cost. The second scheme would abandon retail competition in California and establish the three 3 IOUs as the regulated retail supplier of energy with an obligation to procure energy and ancillary services at least-cost. The problem with this second approach in the current California market is that it would require the CPUC to replicate in its retail rate-making staff the expertise of a wholesale electricity trading firm to verify whether each IOU’s forward market purchases were in fact just and reasonable. On the other hand, with retail competition, the CPUC would only need to ensure low barriers to entry for electricity retailers. It could then rely on the competition among these entities in the price plans they offer to retail customers to provide strong incentives for all load-serving entities to procure wholesale energy and ancillary services at the lowest possible cost. For this reason, the both the October 1999 and September 2000 Reports urged the CPUC to introduce, as soon possible, the regulatory infrastructure necessary for robust retail competition.

However, the introduction of retail competition would do little in the short term to mitigate the significant market power that currently exists in the California market. Without a market power mitigation plan, retail electricity prices would have to rise significantly in the short-term, even if retail competition was adopted with all of the necessary regulatory infrastructure described in the October 1999 MSC Report. For this reason, later in this report, we outline a market power mitigation plan that will protect consumers over the short term from the exercise of market power and allow the CPUC to introduce retail competition to protect California consumers from the exercise of market power over the long term. As the above discussion makes clear, this market power mitigation plan does not require the elimination of the PX Buy/Sell requirement, only its re-formulation as a scheduling requirement for the three IOUs.

The October 1999 Report noted that the PX buy/sell requirement could be maintained as a Scheduling Coordinator requirement. Under this scheme, the IOUs would be required to schedule all of their day-ahead and day-of generation and load obligations through the PX. The IOUs would be free to enter into whatever forward financial and physical transactions for energy and ancillary services they wished, but they would still be required to schedule all of their forward generation and load obligations through the PX. This form of the PX Buy/Sell requirement could be accomplished within the current PX market design or the PX could offer a lower-priced scheduling service. Under the former scheme, the IOUs would simply bid their forward generation commitments for a given hour in at a price of zero and their forward load commitments for a given hour in at the PX price cap to guarantee that they are scheduled on a day-ahead basis. Under the second scheme, the PX would offer a lower-priced scheduling service when the IOU submits to the PX a balanced forward energy and generation schedule. The IOUs could also make use of the PX day-ahead and hour-ahead market to buy or sell incremental energy on a day-ahead and hour-ahead basis. For example, an IOU owning no generation with forward contracts for supply of 500 MWh and a load obligation of 700 MWh in a given hour could use the PX's new scheduling service to submit a balanced schedule to the PX of 500 MWh and it could bid the remaining demand into the PX's day-ahead energy market to purchase a hedge for the remaining 200 MWh of load obligation in that hour at the resulting PX market-clearing price. For the 500 MWh load obligation supplied under the forward contract, there is no need to determine a day-ahead price for this quantity of energy scheduled, because it has already been purchased by the IOU at a previously negotiated price.

Both the October 1999 and June 2000 MSC Reports noted that all market participants benefit from a transparent and anonymous day-ahead and hour-ahead market to trade their forward energy commitments. Eliminating the PX Buy/Sell requirement and burdening the PX with incurring the significant costs (described below) necessary to implement the $150/MWh soft-cap bid mitigation measures as recommended in the Proposed Order makes it very unlikely that the PX can maintain sufficient volume to continue to provide this benefit to all market participants.

Because the PX is simply one of many Scheduling Coordinators in the California market, it already faces significant competition in the services it provides. Saddling the PX with the requirement to implement the $150/MWh soft-cap in the Proposed Order will simply cause generation unit owners wishing to avoid the complications of the $150/MWh soft-cap to schedule their energy through any one of the many current SCs in California (which include affiliates of the three IOUs) or any new SCs that might enter the market. Any measure which hinders the ability of the PX to attract generation and loads to trade in its markets relative to the energy and ancillary services markets run by other SCs, will simply drive volume away from the PX, with little reduction in the amount of market power exercised in the California market.

As will be discussed below, asymmetric penalties on loads relative to generation for under-scheduling as recommended in the Proposed Order will further enhance the ability of generation unit owners to exercise market power in the California market. Because generation unit owners know that the loads will be required to pay up to a $100/MWh under-scheduling penalty under the Proposed Order, the experience of the past summer with the ISO's current Replacement Reserve penalty scheme suggests that generation unit owners should be able to capture virtually all of this expected under-scheduling penalty in the form of higher wholesale prices from loads in forward market transactions inside or outside of the PX markets.

Therefore, any price cap measure should be imposed only on the ISO imbalance energy market. This is the only imbalance energy market in California, so that generation unit owners and load-serving entities have no other option but to trade in this market. As the first 28 months of operation of the California market has demonstrated, a price cap on the ISO's real-time energy market effectively caps the price of energy in all forward markets, including the PX markets. Up until the ISO implemented the Replacement Reserve penalty scheme, during August of 1999, the day-ahead PX zonal price never exceeded the ISO's real-time price cap. As discussed in the September 2000 MSC Report, this Replacement Reserve penalty scheme is a major factor contributing to the under-scheduling in the California market.[2]

[2] The March 1999 MSC Report ("Report on the Redesign of the Markets for Ancillary Services and Real-Time Energy," March 25, 1999) strongly advised against implementing this Replacement Reserve penalty scheme. The March 1999 Report argued that it would increase the ability of generation unit owners to exercise market power without significantly improving system reliability.

Our market power mitigation plan presented later in this report recommends retaining a damage control price cap on the ISO's real-time energy and ancillary services markets. Because the PX faces significant competition from other scheduling coordinators, we recommend imposing no additional price caps on the PX market beyond those currently in force. Any market power mitigation measures imposed on the PX, but not on all other existing and potential Scheduling Coordinators will simply result in trading volume leaving the PX, with little change in the amount of market power exercised in the California market.

Under-scheduling Penalty

The Commission proposes an under-scheduling penalty applicable only to loads and not to generation. While the proposal could be effective to provide incentives to load not to under-schedule, it is also likely to be factored into seller bidding behavior into the PX. This will result in sellers increasing their bids into the PX to reflect the penalty that buyers face if they purchase in the ISO real-time market rather than the PX. This is precisely the same mechanism that operated under the ISO's Replacement Reserve penalty scheme. Additional Replacement Reserve costs incurred by the ISO due to under-scheduling are charged to loads in proportion to the amount of energy they consume beyond their day-ahead energy requirements. The September 2000 MSC Report describes in detail the perverse incentives for under-scheduling by loads and generation unit owners created by this scheme. If a $750/MWh Replacement Reserve penalty in June of 2000 didn't solve the under-scheduling problem, it is unlikely that a $100/MWh penalty administered through the same mechanism will be any more effective in solving the problem. For this reason, we strongly recommend against adopting the under-scheduling penalty in the form given in the Proposed Order.

As an alternative to the under-scheduling penalty, we recommend a real-time energy trading charge that is applicable both to generation and load, that assesses a charge on loads and generation unit owners for real time trades more than some pre-specified percentage of their scheduled load or generation respectively. Under this arrangement, both generation unit owners and load-serving entities have strong incentives to accurately schedule. More important, neither has the upper hand in the forward market because the trading charge is assessed in an even-handed manner to generation unit owners and load-serving entities. This recommendation is outlined in detail the September 2000 MSC Report.[3] We emphasize that in order for a real-time trading charge to eliminate the incentives for under-scheduling by load and generation there should be no distinction between instructed and uninstructed deviations from schedule by either generation unit owners or load-serving entities in assessing this trading charge. The trading charge should be administered on a unit-by-unit or load take-out-point basis and it should depend on the absolute value of the difference between the actual generation supplied by that unit or energy consumed at that load take-out-point and the day-ahead or hour-ahead schedule of that unit or at that take point. The trading charge can also depend on the absolute value of both of these differences: (1) actual generation minus the day-ahead schedule and actual load minus the day-ahead schedule and (2) actual generation minus the hour-ahead schedule and actual load minus the hour-ahead schedule. The September 2000 MSC describes the logic for imposing the real-time trading charge in this manner.

A straightforward way to see the perverse incentives created by applying this charge differentially to instructed versus uninstructed deviations is to note that the way a market participant schedules and operates generation units that it owns and manages the loads that it

[3] "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000

serves can impact the amount of instructed deviations from schedule the ISO must make to that market participant for each unit in its generation portfolio. Imposing a trading charge on only uninstructed deviations, not all deviations from schedule will continue to create incentives for market participants to create imbalances that they are subsequently able to correct through instructed deviations from their schedule by one of their units at a paid at a price greater than or equal to the amount of that unit's bid into the real-time market.

As emphasized in the September 2000 MSC report, it is important understand that all forward schedules submitted to the ISO must be balanced in the sense that the amount of generation equals the amount of load. If aggregate load is under-scheduled by a certain amount, then, by definition, aggregate generation is under-scheduled by this amount. The Proposed Order assigns the cost of under-scheduling by generation and loads to loads only. This undercuts the goal of the Proposed Order "to make markets in the region work for the ultimate benefit of consumers—assuring a reliable supply of energy at the lowest reasonable rate." As discussed in the September 2000 MSC report, assigning the cost of under-scheduling to load creates an opportunity cost for loads selling into the real-time market. If a scheduling coordinator is unable to procure 95% of its real-time consumption in the forward market it will be subject to the under-scheduling penalty in the Proposed Order. Generation unit owners know this and will be able to obtain higher prices for forward market transactions because they know load-serving entities face this under-scheduling penalty. The real-time trading charge described above and outlined in detail the September 2000 MSC report does not favor generation unit owners or load-serving entities in the forward market price-setting process. Both face the prospect of the same per-unit real-time trading charge to the extent that their forward market commitments are less than 95% of their real-time energy consumption or supply, whether or not the some or all these deviations from their day-ahead and hour-ahead schedules are due to having a bid accepted in the ISO's real-time energy market. At this point it is important to emphasize a unique feature of the California market design relative to other ISOs in the US which necessitates this form of a real-time trading charge to encourage accurate scheduling by loads and generation. The New York, New England and PJM ISOs commit generation units to their minimum operating point on a day-ahead basis. Generators submit bids giving their willingness to supply energy on a day-ahead basis to the ISO. The ISO then determines which generation units must be committed to at least their minimum operating level to meet the forecast demand for the following day. The system operator in these three ISOs can commit on a day-ahead basis as many units as it deems necessary to ensure that sufficient generation capacity will be available the following day to meet the system's actual energy needs.

In contrast, the California ISO relies solely on economic signals to determine how many generation units will be committed to provide energy on a day-ahead basis. Scheduling Coordinators (SCs) submit balanced generation and load schedules on a day-ahead and hour-ahead basis to the ISO. Under the California market design, the ISO does not commit generation capacity on a day-ahead or hour-ahead basis, it merely allocates transmission capacity among the SCs competing to make use of it in their day-ahead and hour-ahead energy schedules. Consequently, unless both generation unit owners and load-serving entities face the proper economic incentives to accurately forward schedule, there is no guarantee that enough capacity will be scheduled in the California forward markets to meet its load requirements during all hours of the following day.

Because, the California ISO does not commit generation units on a day-ahead basis, it does not have the option available to the other US ISOs to commit more capacity to meet its forecast of electricity demand for the following day. Because day-ahead commitment is the result of voluntary decisions by market participants, if the ISO's real-time energy price cap is set too low, the California ISO must sometimes provide additional economic incentives to generation unit owners to commit additional capacity on a day-ahead basis. Currently, the California ISO accomplishes this is through out-of-market (OMM) calls to generation unit owners located outside of the ISO control area and by purchasing additional Replacement Reserve on a day-ahead basis. The perverse incentives for accurate forward scheduling by generation unit owners created by these two discretionary actions by the California ISO is discussed in the September 2000 MSC Report. This report recommends modifications of both these mechanisms to eliminate the incentives for under-scheduling and the higher energy and ancillary services price this underscheduling creates. These recommendations are summarized below.

We should emphasize that the self-scheduling aspect of California market design is consistent with the stated goal of the Proposed Order "to make markets in the region work for the ultimate benefit of consumers—assuring a reliable supply of energy at the lowest reasonable rate." In fact, the design may have the to potential to come closer to achieving this goal than other market designs in the US. To illustrate this point, consider the New York ISO. Here the system operator determines whether additional generation units are needed on a day-ahead basis to meet the ISO's forecast of demand during the next day and commits these units as part of the day-ahead scheduling process. One by-product of this process is that on the average, day-ahead energy prices are higher than real-time energy prices in the New York ISO. In contrast, because of the incentives for scheduling by loads and generators created by the California market rules described in detail in the September 2000 MSC Report and other previous MSC Reports, average prices in the PX day-ahead market have been lower than average prices in the ISO real-time market. In both the NYISO and CAISO markets, most generation is scheduled on a day-ahead basis. However, California consumers are paying the lower of the two prices for the larger fraction of their load. In contrast, New York consumers are paying the higher of the two prices for the vast majority of their consumption.

The September 2000 MSC Report proposed several market rule changes that we strongly recommend that the Commission adopt in place of its under-scheduling penalty on loads to encourage more accurate scheduling by loads and generation unit owners and reduce the ability of generation unit owners to exercise market. These rule changes are: (1) a real-time trading charge, (2) a change in the Replacement Reserve cost allocation scheme and (3) a commitment by the ISO not to pay more than the ISO's real-time energy price cap for out-of-market calls. The September 2000 MSC Report also recommended immediate disclosure to all market participants the identity, quantity of energy and length of commitment associated with all out-of-market calls. As discussed in the September 2000 MSC report, these market rules changes will also enhance system reliability, because all market participants will have a strong economic interest in maintaining system balance. If the Commission's final order recommends adoption of these market rule changes along with the market power mitigation measures described later in this Report, we are confident that these remedies will provide the system reliability and market prices that the Commission desires.

Soft-Cap Price Proposal and Refund Obligation Risk

We regard the Commission's soft-cap proposal as largely ineffective to constrain the exercise of market power by sellers into the California market. First, the price constraint applies only to sales to the PX and ISO auction markets. Bilateral sales to end-users, sales outside of

California, and—assuming the PX buy/sell requirement is eliminated—sales directly to the California IOUs are not subject to the soft-cap. In our view, for any price cap--soft or otherwise--to work, it has to apply to all entities that sell directly or indirectly to the PX, the ISO, any California load-servicing entity, or any end-user in California. Otherwise, sellers can readily make bilateral arrangements with entities not subject to the price cap that subsequently sell into the California market at a price above this price cap when system load is sufficiently high to require this energy. Second, a significant percentage of sales into the PX and ISO are made by marketers or other intermediaries who may be purchasing from generators at prices in excess of $150/MWh, and if they do so, readily will be able to establish a cost basis in excess of $150/MWh for their PX and ISO sales. Third, if the FERC allows opportunity cost to be a valid measure of cost, it will not be difficult for a generation unit owner to find an entity in the WSCC to say that it is willing to buy at virtually any price. This would validate virtually any bid on an opportunity cost basis. Fourth, if the FERC allows bids that recover some portion of fixed costs, it will be extremely difficult to determine what the appropriate contribution to fixed cost is for each hour a generation unit is operating. This is simply a re-statement of the classic problem in regulatory economics of how to recover fixed costs from average per unit cost-of-service regulated prices. Fifth, the Proposed Order appears to deprive the ISO of authority to maintain a purchase price cap after December 31, 2000, potentially requiring the ISO to accept bids in any amount if they can be cost-justified.

Even though ineffective, the Proposed Order, if implemented, is likely to exacerbate supply problems in California because of uncertainty as to whether and how the Commission's refund policy will be carried out. In times of tight supply margins in the WSSC market, generators and marketers will sell into markets that are not subject to a refund condition, rather than selling into markets that are. The imprecision of the Commission's refund policy is likely to make this worse. It is not clear from the Proposed Order what kind of cost justification will suffice, or how or when it is to be made. The order does not make clear whether there is a safe-harbor for prices below $150 or whether cost justification can be required for these sales also.

Finally, failure to articulate the extent to which the soft-cap and refund requirements apply to sales from new capacity may result in a reduction of construction of new units in California. Because the supply conditions in the entire WSCC are likely to be tight for the next two years, new units will have an incentive not to locate in California and to sell their output outside of the California market and into markets characterized by less regulatory uncertainty.

Combined Impact of End of PX Buy/Sell, Under-Scheduling Penalty, and Soft-Cap

Although each of the Proposed Order's major recommendations considered individually will do little to solve California's current market power and reliability problems, when considered as a package they may present greater opportunities for generators to exercise market power and set higher wholesale prices that must be passed on to California consumers. The following sequence of events seems likely to occur if the three major remedies in the Proposed Order are implemented.

First, the PX and ISO will both incur significant software and market operations costs to implement the pricing, billing, and compliance functions associated with the $150/MWh soft-cap. Particularly, for the PX, it is unclear how the soft-cap will be implemented within its current market rules, because all market participants are free to submit both demand and supply portfolio bids. By design, portfolio bids need not correspond to specific generation units. For this reason, it is unclear how to cost-justify portfolio bids.

Demand and supply portfolio bids are simply piecewise linear functions giving an entity's willingness to supply or demand energy as a function of price. Each supply portfolio bid is a piecewise linear function that begins at the point (0,0) in (quantity,price) space and ends at the point (qs(max),2,500), where qs(max) is the maximum amount the market participant is willing to supply at a price of $2,500/MWh from this portfolio bid. Therefore, under the current PX rules each portfolio bid function must have at least one linear segment of bids above the $150/MWh soft cap in order to connect to the endpoint (q(max),2500). Each demand portfolio bid is a piecewise linear function that begins at the point (0,2500) and ends at the point (0,qd(max)), where qd(max) is the amount demanded at a price of $0/MWh associated with this portfolio bid. Each PX market participant can submit as many demand and supply portfolio bids as they wish for each hour of the PX market. Many PX market participants submit a large number of both supply and demand portfolio bids during each hour of the PX market, even market participants that have no retail load to serve. The sum of all supply portfolio bids at each price yields the aggregate PX supply function. The sum of all demand portfolio bids at each price yields the aggregate PX demand function. The intersection of the aggregate PX supply function with the aggregate PX demand function yields the unconstrained PX price. For each PX market participant, the total quantity of its portfolio supply bids at a price less than the unconstrained PX price minus the total quantity of its portfolio demand bids at a price above the unconstrained PX price equals that market participant's net energy sales in the PX.

Another difficulty with imposing the $150/MWh soft-cap is that a PX market participant willing to hedge a little less energy in the PX at a significantly higher price could submit a demand-portfolio bid function with positive demand above the price of $150/MWh in order to set the market-clearing price above $150/MWh. These are just a few of the complications that must be overcome to implement the proposed cap on the PX market.

Assuming the necessary software and market rule changes have been implemented on the PX markets, the likely response of generation unit-owners is not to bid into the PX market during any time period when they can expect to sell their energy for more than $150/MWh. Since June 2000, average prices in the PX and ISO markets have been approximately $120/MWh. This average price implies that there will be many hours when very little generation will bid into the PX markets. These generation owners can either wait until the ISO real-time energy market to sell their energy or arrange a forward market sale outside of the PX or outside of California. This forward market sale outside of the PX is made possible by the elimination of the PX Buy/Sell requirement on the three IOUs. The combination of the end of the PX Buy/Sell requirement with the $150/MWh soft-cap on PX transactions is likely to result in little if any volume in the PX during periods when value of energy to load-serving entities is likely to be greater than $150/MWh.

The proposed $100/MWh penalty on load-serving entities for submitting forward schedules that are less than 95% of their real-time energy consumption will increase the number of hours when the opportunity cost of energy to load-serving entities is greater than $150/MWh. According to the Proposed Order, buying in the forward market versus the real-time energy market allows load-serving entities to avoid the $100/MWh under-scheduling charge. Generation unit owners recognize this, so that during time periods when a significant amount of California generation capacity is needed to meet California demand, generators will factor this $100/MWh under-scheduling penalty into their willingness to supply energy to load-serving entities. Particularly during high load hours, the experience with the ISO's current Replacement Reserve penalty suggests that generation unit owners can expect to receive virtually all of the $100/MWh penalty in the form of a higher forward energy price. Any load-serving entity that refuses to pay a forward energy price that includes this $100/MWh penalty, must purchase at the real-time price and incur the $100/MWh under-scheduling penalty on virtually of its purchases.

Consequently, combining the three remedies in the Proposed Order has the potential to cause the PX and ISO to incur significant compliance costs, drive a large quantity of volume away from the PX, and enhance the opportunities of generation unit owners to increase forward wholesale electricity prices.

Abandoning the soft-cap for the PX market, and only imposing it on the ISO markets, will lead to problems similar to those described above. In most periods, load-serving entities will most likely demand bid into the PX to limit zonal PX prices to less than $150/MWh. This will allow them to purchase some of their load at a price less than or equal to $150/MWh. They will purchase some of their remaining obligations from forward market transactions outside of the PX. Any remaining load obligations must be purchased from the ISO real-time energy market. If the load-serving entity's real-time energy purchases are large enough, it will incur the under-scheduling charge in the Proposed Order. This wholesale purchasing behavior is rational so long as total wholesale energy costs to the load-serving entity are minimized using this purchasing strategy. Particularly, during high demand periods, the amount of purchases in the ISO's real-time energy market are still likely to be extremely large under the Proposed Order's $100/MWh under-scheduling charge

It is important to emphasize that during early June 2000 there was significant under-scheduling of load and generation. At this time load-serving entities faced a Replacement Reserve penalty far in excess of $100/MWh, yet they still chose to purchase in the real-time market rather than pay higher prices in the PX market. Consequently, it seems unlikely that a $100/MWh under-scheduling penalty will cause load-serving entities to purchase more in the forward market if generators face the soft-cap in the ISO markets. Load-serving entities may prefer to subject generation unit owners willing to supply for more than $150/MWh in the forward market to the bid review process in the ISO real-time market and risk the paying the under-scheduling charge for a fraction of its real-time energy market purchases. On the other hand, generation unit owners may feel confident that they will be able to cost-justify their bids in excess of $150/MWh in the ISO market given that they have the option of using either an opportunity cost or cost-of-service justification. This could cause these generation unit owners to be unwilling to settle for prices at or below $150/MWh in forward markets such as the PX day-ahead market during many hours of the year.

By allowing an opportunity cost justification for bids into the ISO markets, the Commission is implicitly allowing market-based pricing without a price cap. If a market participant is able to find a willing buying somewhere in the WSCC for its power, that represents a cost that will have to be paid for energy by California consumers. One can easily imagine a scenario where a large number of generation unit owners claim as their opportunity cost the same offer to purchase by a single load-serving entity in the WSCC. Which generation unit owner's bids are cost-justified is a completely arbitrary. All of the generation unit owners had the opportunity to sell at this price and all of them presumably did not sell. Following this logic further, one can then imagine that under this scheme, all generation unit owners will have a common interest in finding the highest willingness to pay by a load-serving entity in the WSCC. Each of them can bid that willingness to pay into the ISO's real-time energy market and be paid as bid on an opportunity cost basis.

Allowing an average cost justification for bids submitted to ISO real-time energy market can also cause California consumers to pay extremely high energy prices. For example, allowing a generation unit owner to include a portion of its fixed costs and its start-up and no-load costs in its operating costs for an hour can lead to bids to provide energy for a single hour significantly in excess of $4000/MWh. In fact, under the original Reliability Must-Run (RMR) contracts, there were several units that had RMR "Contract A " per-unit payments at this rate.[4]

For these reasons, both the opportunity cost and average cost justification for bids envisioned under the soft-cap approach, even if they were only imposed on the ISO markets, could result in annual wholesale energy costs that are equal to or greater than those that have occurred under current market rules, despite the fact that all cost-justified bids in excess of the soft-cap are paid as-bid. For this reason, we believe it is highly unlikely that implementing the $150/MWh soft-cap as described in the Proposed Order will achieve its stated goal "to make markets in the region work for the ultimate benefit of consumers—assuring a reliable supply of energy at the lowest reasonable rate."

We believe that the wholesale energy and ancillary services prices that would be charged to California consumers if the three major remedies in the Proposed Order were implemented would continue to be unjust and unreasonable.

Refunds and Penalties for Abuse of Market Power

Significant market power has been exercised in the California during the Summer and Autumn of 2000. For this reason, we strongly urge the Commission to pursue all legal avenues available to obtain the refunds for the unjust and unreasonable wholesale rates charged for all market participants since the refund effective date of October 2, 2000. Only those market participants that agree to a market power mitigation proposal such as the one described later in this Report should be excused from refund liability.

[4] The August 1998 MSC Report a contains a full discussion of RMR Contracts and payment rates.

Particularly in light of the scheduling and bidding behavior of market participants during early November 2000, we believe it is premature to conclude that there have been no abuses of market power in the California electricity market. For this reason, we encourage the Commission to expand its investigation of the need for refunds and abuse market power. If market participants agree to a market power mitigation proposal such as the one described later in the Report, the Commission could then decide to suspend these investigations. The events of early November 2000 also point out the necessity of FERC-imposed mandatory reporting to the ISO of all scheduled and unscheduled generation unit outages in the California ISO control area. The Commission may also want to consider giving the ISO greater discretion to coordinate scheduled outages of generation units and to impose sanctions on unit owners for unjustified unscheduled outages.

The Proposed Order does not state what scheduling, bidding or operating behavior by generation unit owners would in the Commission's opinion, qualify as significant exercise of market power sufficient to cause the Commission to seek refunds. For this reason, it is extremely difficult for the MSC and the ISO's Department of Market Analysis to be as useful as possible in helping the Commission in its efforts to determine the circumstances in which refunds will be required due to the exercise of significant market power.

The MSC stands ready to provide to the Commission with what we suspect are instances of the exercise of significant market power by specific market participants. We encourage not only the Commission, but other law enforcement agencies as well, to use their authority to request from these market participants the necessary information to confirm whether these suspicions about the exercise of significant market power are in fact correct.

The Commission needs to formulate standards for determining whether refunds will be required where it determines rates are not just and reasonable and how to allocate the liability for these refunds to specific market participants based on their behavior in the markets. Over the past 2 1/2 years, the MSC has devoted significant attention to analyzing bidding and scheduling behavior in the PX and ISO energy and ancillary service markets. These analyses are summarized in numerous MSC reports submitted to the Commission. The MSC could provide a number of instances of what it suspects are suspicious bidding and scheduling behavior during the Summer and Autumn of 2000 which the Commission's investigation staff could then use to request further clarification and cost-justification from specific market participants. In addition, we are also willing to provide assistance to the Commission in the very difficult task of determining market participant behavior worthy of refunds and how to allocate liability for refunds to specific market participants for behavior the Commission deems worthy of refunds. Additional clarity from the Commission in either of these dimensions will decrease the likelihood that future actions deemed worthy of refunds will occur in the California ISO or in the other US ISOs.

Forward Contracts in Competitive Electricity Markets

With the singular exception of California, virtually all competitive electricity markets within and outside of the United States began with some form of "vesting contracts" in place to protect electricity consumers from wholesale spot price volatility during the early years of the market. Under these contracts, the new operator of a generating facility must sell a pre-specified quantity of energy at a pre-specified price from this plant. These vesting contracts also take the form of forward financial contracts that are cleared against the spot price at the time of delivery.

In these instances, a vesting contract is a financial hedge for pre-specified quantity of energy at a pre-specified price. Vesting contracts are usually purchased by load-serving entities in order to hedge the financial risk associated with serving their captive customers on fixed retail rates during the period before full retail competition is introduced. Although the fraction of system load that is covered by the vesting contract declines over time as the spot market matures, load-serving entities and generation unit owners can enter into forward financial contracts at mutually agreed upon terms at any point in time. Load-serving entities usually sign forward financial contracts with generation unit owners to make up for the decline in the quantity of vesting contracts. Consequently, in all other competitive electricity markets currently operating around the world, a large fraction of all energy consumed is hedged by that load under long-term forward contracts.[5]

The California market is unique relative to other markets in the world because of its conscious decision to eschew vesting contracts and, during the first-year of the operation of market, to prohibit all forward contracting by the three investor-owned utilities outside of the PX day-ahead market. This meant that each day, all load-serving entities were paying a price for energy that was determined at most, one day before the actual energy was delivered. The impact of these restrictions on the performance of the California energy and ancillary services market has been discussed all previous MSC Reports, in most detail in the October 1999 and September 2000 reports. The major conclusion of these reports is that the spot price volatility and the

[5] There are a number of articles describing the use of vesting contracts in the initial stages of competitive electricity markets. Helm and Powell (1992) describe the use of vesting contracts in the England and Wales market. They argue that during the first year of the England and Wales market vesting contracts significantly reduced price volatility and average prices. Green (1999) estimates the amount of forward contract cover in the England and Wales market during subsequent years of the market. He also presents an economic illustrating that when a large fraction of a generator's output is covered by a forward financial contract, it has a strong incentive to bid close to its marginal cost in the spot market. Wolak (2000) describes the case of vesting contracts in the Australian electricity market. He derives an economic model of optimal bidding behavior in a competitive electricity market and illustrates the impact of forward financial contracts on bidding behavior.

opportunities for the exercise of market power that have existed in California are not surprising given the lack of forward contracting in this market. In order to gain some appreciation of the implications of this over-reliance on spot markets, imagine what would happen to air travel prices if it was only possible to purchase airline tickets one day-ahead of the actual travel date.

The lack of significant forward contracting in the California market increases the incentives for and ability of generation unit owners to exercise market power in spot energy and ancillary services markets. To see this, consider the following example of a firm with some ability to affect the market-clearing price in the spot electricity market. Let QS denote the amount of energy it produces, PS the spot price of energy, and MC is its marginal cost of producing electricity. Suppose this firm has previously sold a two-sided contract-for-differences (CFDs) at a price PC. Let QC denote the quantity of CFDs sold. The payoff to the seller of a two-sided CFD is (PS – PC)*QC. If PS is greater than PC, the seller pays to the buyer the difference between PS and PC times QC. If PC is greater than PS, the buyer pays to the seller the difference between PC and PS times QC. For simplicity, assume that MC is the same value for all output levels. The variable profit earned by the firm is:

$$\text{Variable\_Profit(PS)} = (PS - MC)*(QS - QC) + (PS - MC)*QC.$$

The first point to note from this variable profit function is that until the firm covers its forward financial contract position, QC, with physical sales, QS, it will use its ability to influence the market price, PS, to set it lower than its marginal cost, MC. This incentive operates because when QS is less than QC, the only way for the first term in the equation to make a positive contribution to variable profits is if PS less than MC. A second point to note is that if QS is greater than QC, and QC is non-zero, then the firm does have an incentive to use its market-power to raise prices. However, the presence of forward financial contract dulls this incentive to raise the spot price, PS, because the firm only earns this price for its spot market sales beyond QC. Consequently, to the extent that QS is only slightly greater than QC, the firm has less of an incentive to raise prices through its bidding behavior. Consider the case that QC is equal to zero. Here the marginal incentive of the firm to raise PS by exercising its market power is greatest, because it earns this higher price for all of its spot sales, QS.

This example illustrates an important point associated with assessing the benefits to load-serving entities of forward market purchases. Specifically, the forward market commitments made by or imposed upon a generation unit owner significantly alters its incentives to raise prices or withhold capacity from the spot market. However, generation unit owners understand this mechanism, and are reluctant to commit to forward financial contracts at prices that do not yield the same expected profit stream as they could obtain from their forecast spot market sales. Consequently, to make a forward market sale attractive to a generation unit owner, the load-serving entity may have to offer an equivalent forward market price. However, once this contract has been signed, this generation unit owner now has the incentive noted above to bid more aggressively in the spot market, with the result being lower spot prices. Deeming these forward contracts imprudent after fact because of the lower spot price would be inappropriate, because these lower spot prices would not have occurred if the forward contracts were not in place. This aspect of forward contracting and its impact on generation unit behavior in spot markets considerably complicates any assessment of the prudence after the fact, of any forward market purchases.

An additional benefit of forward financial contracts is the protection from spot price fluctuations they provide to load-serving entities. A load-serving entity that holds the other side of the two-sided CFD in the above example is completely hedged against spot price risk if its consumption is equal to QC. To the extent its consumption differs from QC, it bears spot price risk only on the deviations of its actual consumption from QC. A load-serving entity holding a significant fraction of its expected sales in CFDs, has effective price certainty on its wholesale energy obligations and can therefore set a fixed retail price and be reasonably assured of covering its costs regardless of what happens to spot electricity prices. Moving to the case of the California electricity market, if all load-serving entities in California held forward financial contracts for all of their energy obligations to small business and residential consumers, the CPUC would know that these entities have wholesale price certainty for these customers. This wholesale energy cost certainty would allow the CPUC to set a fixed default retail rate for these two customer classes. The CPUC could also allow other retail pricing plans where these customers voluntarily take on wholesale price risk in exchange for the opportunity to receive lower average electricity prices (because they alter their demand in response to wholesale price changes) than under the fixed retail price.

A final benefit of forward financial contracting is that it effectively renders moot any discussion of the relative advantages of pay-as-bid versus single-price auction mechanisms for electricity spot market designs. In a competitive electricity market, regardless of whether the spot market is cleared using a pay-as-bid or uniform price auction, electricity that is produced and delivered within a given hour is being paid according to wide variety of forward market contract prices. For example, one would expect that the owner of a low-variable-cost, high-fixed-cost unit would prefer to operate it as a base-load facility. Consequently, the owner of this unit would be willing to sign a multi-year two-sided CFD at a price close to the expected average annual price of electricity because it expects to be operating this unit in virtually all hours of the year at a constant rate of output. The owner of a peaking unit that expects to only operate during

10 to 20 peak hours of the year, would probably engage in a different set of forward sales. This unit owner might instead sell a one-sided CFD for a significant fraction of the unit's expected output. Under a one-sided CFD, in exchange for an up-front payment from the buyer, the unit owner pays out the maximum of zero and the difference between PS and PC times the number of units of the contract sold, QC, to the buyer of the CFD, where PS is the spot price and PC the contract strike price. This CFD provides the purchaser with insurance against price spikes in the spot market for QC units of output, but does not require the purchaser to make any payments to the generation unit owner that sold the contract if PS is less than PC, besides the up-front payment at the time the contract is signed. This up-front payment should help the unit owner cover the annual fixed costs associated with running its unit. For the hours covered by this one-sided CFD, the unit owner can earn a maximum price of PC by selling QC units in the spot market. The unit owner could cover the remainder of its annual revenue needs through sales in the spot market. Finally, a unit owner that primarily serves intermediate load levels, may choose a combination of two-sided and one-sided CFDs, as well as some sales into the spot market. Each of these contracts would be negotiated with individual buyers, so that the unit owner would have a portfolio of forward market positions at a variety of prices.

In competitive electricity markets with active forward markets, in any given delivery hour all market participants—loads and generation unit owners—have a portfolio energy purchases and sales at a variety of prices. Consequently, regardless of whether the spot market is cleared using a uniform-price auction or pay-as-bid auction, electricity is delivered during a given hour according to a large number of forward prices negotiated at a number of different times in the past and under a variety of contract forms.

It is important to emphasize the reason that energy is delivered under a variety of prices under either spot market price-setting process. Forward contracts are negotiated under different terms and conditions at different times before delivery takes place. Presumably, these prices reflect the best information at the time contract is negotiated of its value to the buyer and seller. New information about the market-clearing price of electricity at a given time in the future continually arrives and it processed by buyers and sellers of forward electricity contracts. The continual arrival, over time, of new information about spot market conditions at the delivery or clearing date of a forward contract is the major reason for the large number of prices for electricity delivered in the same hour. We would expect that a forward financial contract for delivery of 1 MWh energy in a given hour in the future could not consistently sell for a higher price through a bilateral negotiation or pay-as-bid market, versus a uniform price auction market. Otherwise, the buyer of this contract would instead purchase from the uniform price auction. Conversely, if the price was lower under a uniform price auction, we would expect the seller to move to the pay-as-bid or bilateral negotiation market.

Taking this logic to the case of the pay-as-bid versus the uniform-price auction in the California market, it is important to note that there are both pay-as-bid and uniform price auctions operating in the day-ahead and hour-ahead markets. Market participants wishing to trade in a uniform price auction can do so in the PX markets. Those wanting to trade on a pay-as-bid basis can enter into bilateral deals with any market participant they wish and submit the resulting balanced schedule to the ISO. Once the three California IOUs are given complete freedom to sign forward contracts outside of the PX markets, all market participants will have the freedom to trade in either a pay-as bid or a uniform price auction. Consequently, if the uniform price auction market--the PX--is not disadvantaged with the $150/MWh soft-cap, the

California market allows buyers and sellers to express their unbiased preferences for the pay-as-bid versus uniform price auction on a day-ahead or hour-ahead basis.

The only energy market where there is no choice between a uniform price and a pay-as-bid auction in California is in the ISO's real-time energy market. However, it seems reasonable to expect little divergence between buyers and sellers on their expectations about the market-clearing price (the highest bid necessary to meet demand) an hour before the real-time energy market actually clears, particularly because all market participants know the market-clearing prices (the highest bid accepted to meet demand) for previous hours in the day. If the ISO's real-time market used a pay-as-bid auction, it is unlikely average real-time energy prices would be significantly different from those under the current uniform price auction. All market participants would simply bid their best estimate of the market-clearing price of energy for that hour, and total real-time energy revenues would be very similar to those under the uniform price auction. Consequently, once all market participants are given complete freedom to forward contract and an active forward market has developed, it is difficult to see any significant benefits to consumers in the form of lower energy prices from a pay-as-bid auction mechanism for the PX and ISO markets.

For these reasons, among many others, virtually all observers of the California market agree that robust forward financial markets are needed in California. However, there are currently various impediments to the development of this market in California. The major impediment is the fact, stated in the Proposed Order, that energy and ancillary services prices in the PX and ISO markets reflect the exercise of significant market power. Consequently, any forward contract price that a generation unit owner would voluntarily offer to a load-serving entity in California would reflect this market power. However, the Proposed Order also states that these energy and ancillary services prices are not just and reasonable. Consequently, under Section 206(a) of the Federal Power Act, "the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed and in force, and shall fix the same by order." As a substitute for the remedies in the Proposed Order, we urge the Commission to implement the following regulated forward contract solution as soon as possible to mitigate the significant market power that would be present in any forward contract that a load-serving entity would be offered under current market conditions.

Market Power Mitigation Plan

There are a number of goals that the market power mitigation plan we put forward below is intended to balance. First and foremost, it must protect California consumers that are unable to protect themselves—residential and small business customers—from the significant market power that has been exercised in the California market since June of 2000 and the extremely high and volatile wholesale electricity prices that have resulted. Second, this plan must "jump start" the forward market in California and provide the CPUC with certainty as to wholesale energy and ancillary services prices for small business and residential customers for the next two years. This wholesale price certainly will allow the CPUC to set a fixed default service retail rate that will protect these consumers from the exercise of market power in the spot market over the next two years. Third, this plan must provide the strongest possible financial signals to attract much-needed new generation and transmission capacity to the California market. Fourth, this plan should create the strongest possible financial incentives for the development of price-responsive wholesale electricity demand in the California market. The final goal is to create conditions in the California market which lead to the greatest opportunity for a competitive electricity market to benefit consumers through lower retail electricity prices than would have occurred had the former vertically-integrated monopoly regime in California continued to the present time.

We believe that the market power mitigation plan outlined below is the best available at achieving these goals. However, for this plan to succeed along all dimensions, the Commission and the CPUC must implement complementary market rule changes in a coordinated manner in their respective regulatory domains. If the Commission executes all phases of the plan without the market rules changes of required of CPUC, it is unlikely this plan will achieve all of the goals outlined above. Conversely, if the CPUC implements the market rule changes outlined below without the wholesale market changes recommended in this report, California consumers are likely to incur substantial retail price increases over the next two years.

The Role of FERC in the Market Power Mitigation Plan

The first phase of the market power mitigation plan primarily involves actions by FERC. First, it would compute the total amount of energy sold by each market participant into the California ISO market from December 1, 1999 to November 30, 2000. (Henceforth, we refer to this time period as the "Historic Year") For this purpose a market participant is the owner of any in-state generation units or any entity that sells wholesale electricity in California that is subject to FERC jurisdiction. All affiliated market participants are treated as a single market participant. From FERC's perspective, this makes it relatively straightforward to implement our plan, because each market participant defined in this manner had to file with the Commission at some point in the past to receive market-based pricing authority in California. Consequently, to compute the total amount of energy supplied by a market participant, we take the sum of the annual amount of energy produced by all generation units owned by this entity and the annual net sales of energy from its energy trading affiliates into the California market.[6]

For each market participant defined in this manner, hourly California ISO settlement data can be used to compute the total quantity of energy produced by each instate generation unit that a market participant owns. For imports into the California ISO control area, the ISO settlement data gives the net amount sold into the California market by each Scheduling Coordinator along each tie-line into the ISO control area. The Commission could then request that each Scheduling Coordinator provide a breakdown by market participants of these hourly net imports into California. At the end of this process, the Commission would have the hourly quantity of energy sold into the California ISO for each market participant broken down by generation unit and tie-line into the ISO control area during the Historic Year. Summing these totals over all hours of the year and generation facilities and tie-lines would yield the desired total annual quantity of energy sold into the California ISO control area for each market participant. Call this annual quantity of energy deliveries into the California ISO control area for market participant i, QA(i). Let QA(market) equal the sum of the annual quantity of energy sold into the California ISO control area, over all market participants selling into the California ISO control area during the Historic Year. Let WA(i) = QA(i)/QA(market), the ratio of total annual energy sales by market participant i divided by total annual energy sales over all market participants

We designate WA(i) as the fraction of total market power mitigation that must be provided by market participant i. This market power mitigation will take the form of a regulated

[6] There are also non-FERC-jurisdictional entities selling into the California market. These entities are owned by local, state and federal governments, all of whom have a considerable interest in mitigating the market power that currently exists in the California market and who may be willing to coordinate their pricing policies with FERC.

forward contract that must be offered for a two-year period, beginning as early as this mitigation plan can be implemented.[7]

Our rationale for computing the market power mitigation fraction, WA(i), using the approach given above is that market participants benefitted from the exercise of market power in the California energy market during the Historic Year in proportion to the amount generation they sold into the market. For this reason, we believe that market participants should provide market power mitigation to small business and residential consumers in California in this same proportion. Using the market power mitigation fraction, WA(i), determined in a manner that requires greater mitigation from entities that realized greater benefits from the exercise market during the Historic Year, the hourly forward contract quantity obligation of each market participant for two-year mitigation period should be determined in the following manner. For each month during the Historic Year, compute average daily load shapes for two types of days: weekdays and weekends and national holidays. For illustrative purposes, Figures 1 and 2 compute these load shapes for the months of January 2000 and July 2000. Each point on the graph is the average load during that hour of that type of day—weekday or weekend and national holiday--during that month. Define LOAD(h,d,m) as the value of average total ISO load for hour h of day-type d of month m during the Historic Year.

[7] There are a variety of mechanisms that can be used to determine a market participant's market power mitigation obligation fraction, WA(i). One alternative is to compute this obligation as the share of annual wholesale revenues going to a single market participant during the Historic Year. The difficulty with this approach is the appropriate price to use to value energy deliveries in a given hour. One option would be to simply use the ISO real-time zonal price for the zone that each generation unit is located in. For net imports the relevant price would be the real-time zonal energy price for zone that the net import flows into. The discussion that follows could then be implemented using market participant i's market power mitigation fraction, WA(i), computed in this manner.

Figure 1.
January 2000 Avg. Hourly System Loads

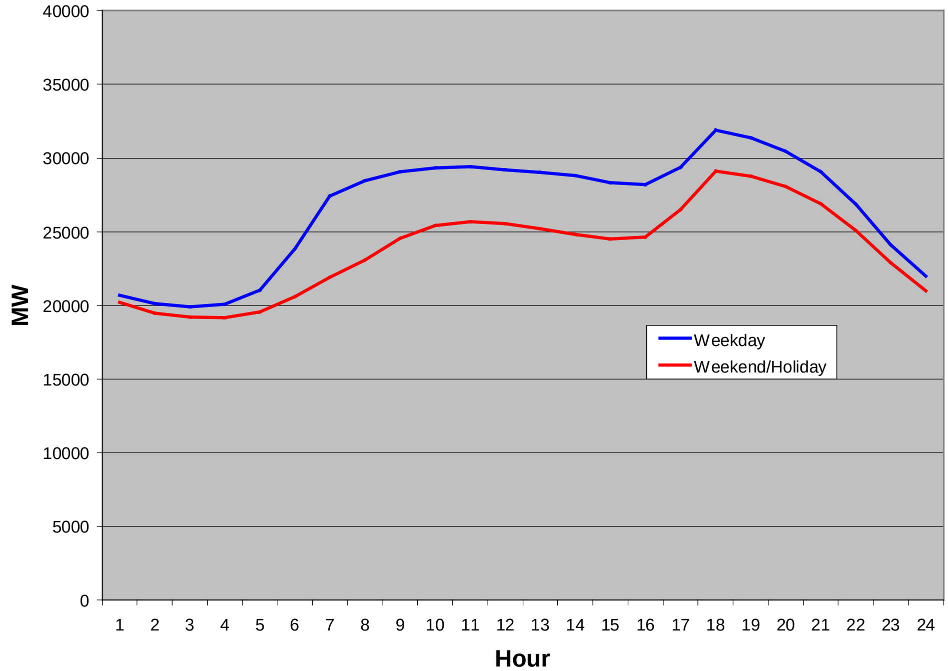
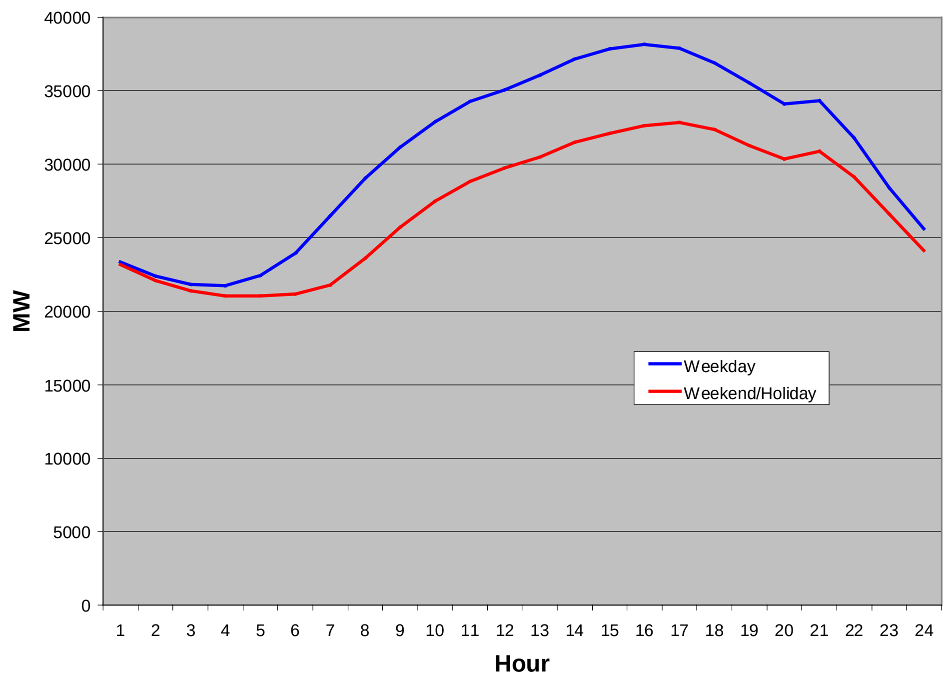


Figure 2.
July 2000 Avg. Hourly System Loads



Because the purpose of our market power mitigation plan is to protect small business and residential consumers from the exercise of market power, we need to compute a reasonably accurate estimate of the hourly consumption of these customer classes. Fortunately, as part of the retail rate regulatory process at the CPUC, each of the three IOUs in California submits to the CPUC the total monthly consumption energy for each rate schedule offered. Figure 3 reproduces one of these tables for June 1999 for San Diego Gas and Electric. Each line of the Table refers to a specific CPUC-approved rate schedule. The column labelled Total Units, gives the total monthly energy sales for each tariff schedule. The Commission, in consultation with the CPUC, should determine which of these rate schedules apply to residential and small business customers. The fraction of total monthly energy sales in that IOU's service territory to these two customer classes can be determined by taking the total monthly consumption under the applicable rates schedules divided by the total monthly consumption over all customer classes. The sum of these shares weighted by the total monthly energy volume in each IOU service territory is a system-wide estimate of the fraction total ISO load being consumed by small business and residential customers. Let X(m) denote this quantity weighted average fraction of total ISO load consumed by small business and residential consumers for each month m of the Historic Year.

Figure 3: Monthly Quantity of Energy Sold by Rate Schedule for SDG&E

LINE	DESCRIPTION	TOTAL UNITS
1	SCHEDULE DR	622,650,499
2	SCHEDULE DR-LI	32,613,876
3	SCHEDULE DM	6,443,060
4	SCHEDULE DS	1,370,874
5	SCHEDULE DT	11,315,075
6	SCHEDULE DT-RV	23,912
7	SCHEDULE D-SMF	63,764
8	SCHEDULE DR-TOU	239,657
9	SCHEDULE DR-TOU-2	3,627,673
10	SCHEDULE EV-TOU	410
11	SCHEDULE EV-TOU-2	17,314
12	SCHEDULE EV-TOU-3	2,345
13	SCHEDULE A	147,616,029
14	SCHEDULE A-1C	6,071,692
15	SCHEDULE A-TOU	11,672,265
16	SCHEDULE AD	11,190,754
17	SCHEDULE AL-TOU	500,756,428
18	SCHEDULE A6-TOU	67,710,731
19	SCHEDULE AO-TOU	110,422,544
20	SCHEDULE NJ	2,044,456
21	SCHEDULE AY-TOU	16,103,008
22	SCHEDULE A-V1	6,045,677
23	SCHEDULE A-V2	2,879,568
24	SCHEDULE A-V3	0
25	SCHEDULE RTP-1	0
26	SCHEDULE RTP-2	2,709,976
27	SCHEDULE S	0
28	SCHEDULE I-3	0
29	SCHEDULE PA	9,521,282
30	SCHEDULE PA-TOU	62,215
31	SCHEDULE PA-T-1	15,520,137
32	SCHEDULE SPEC	500
33	SCHEDULE LS1	1,497,255
34	SCHEDULE LS2	5,371,874
35	SCHEDULE LS3	233,885
36	SCHEDULE OL1	623,974
37	SCHEDULE DWL	19,000
38	SCHEDULE ATS	45,387
39	UNDEFINED RATE CODE	0
40		1,472,409,728

By taking this average fraction of total ISO load consumed by small business and residential customers in month m and multiplying it by the average value of ISO load in hour h or day-type d for month m, gives the total quantity of market power-mitigation forward contracts that must be offered for that hour, day-type and month during the two-year market power mitigation period. Let QCTOT(h,d,m) equal this total contract quantity for hour h of day-type d of month m. In terms of this previous variables, we have OCTOT(h,d,m) = X(m)*LOAD(h,d,m).

The total forward contract quantity for market participant i, in hour h of day-type d of month m for each of the following two years is equal to its market power mitigation fraction, WA(i), times the total forward contract obligation for hour h of day-type d of month m. Let QC(h,d,m,i) equal the forward contract obligation of market participant i during hour h or day-type d, and month m. In terms of the variables given above, we have

QC(h,d,m,i) = WA(i)*QCTOT(h,d,m) = WA(i)*X(m)*LOAD(h,d,m).

At this point, we discuss the rationale for this process for determining each market participant's hourly contractual obligation for the next two years. It is important to recognize the primary goal of this market power mitigation measure is to protect small business and residential consumers from the exercise of market power in the wholesale energy market. Consequently, the daily pattern of the total hourly quantity of regulated forward financial contracts should come as close as possible to the daily pattern of hourly demand for electricity by these customer classes. Choosing the hourly quantities of regulated forward financial contracts in this manner maximizes the protection provided to small business and residential customers from the exercise of market power in the wholesale energy market subject to the constraint that the annual quantity of energy sold under these forward contracts equals the annual quantity of energy purchased by small business and residential customers. Supplying the same annual quantity of market-power-mitigated forward contracts in standard 16-hour blocks or in other standardized load shapes for different sets of hours during the day will not provide the same level of protection for these consumers from the exercise of market power as the annual pattern of forward contract quantities proposed above. We see little reason to attempt more complex adjustments to determine QC(h,d,m,i.). For example, LOAD(h,d,m) could be adjusted for expected load growth over the next two years. X(m) could be adjusted for changes in the composition of electricity demand over the next two years. Any number of adjustments could be made to the process of computing QC(h,d,m,i). Any adjustment to either the allocation of QC(h,d,m,i) across firms or over time is consistent with the goals of this plan, so long as the sum of QC(h,d,m,i) results in a better approximation to the hourly demand from small business and residential consumers over the next two years. Once these contract obligations have been determined the next step is to determine the just and reasonable prices for these hourly contractual obligations. For this process we propose to follow previous Commission orders and legal precedent in determining a just and reasonable forward contract price. As stated in the 1994 Heartland Energy Services, Inc., and Wisconsin Power & Light market-based rate decision, (WL 415138 (F.E.R.C.)), “The Commission’s general standard is to allow market-based rates if the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry.” By this logic, all market participants would be granted market-based rate authority in a competitive market and the resulting rates would be just and reasonable rates if no seller and each of its affiliates did not have market power or had adequately mitigated it. As the DC Circuit Court stated in Tejas Power Corporation versus Federal Energy Regulatory Commission, (908 F.2d 998, 285 U.S. App.D.C. 239), “In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller only makes a normal return on its investment." For these reasons, our just and reasonable price for these forward contracts, is an estimate of the market-clearing price that would result from a market where no firms have significant market power.

Borenstein, Bushnell and Wolak (2000) {BBW) present a methodology, a simplified version of which is summarized below, for computing an estimate of the market-clearing price in the California market when no market participant possesses significant market power.[8] To compute the hourly contract price for hourly h of day d in month m, PC(h,d,m), associated with QC(h,d,m,i), we propose to implement a simplified version of the BBW methodology using average hourly day-ahead import adjustment bids for the 24 hours of two representative day-types (weekend and weekday and holidays) for each month during the Historic Year.

We provide a simple graphical example of how this computation would proceed for a specific hour, day-type and month. For a specific hour, day-type and month in the Historic Year we would compute the average of all aggregate net import supply curves into California for both day-types in that month. For this process, we would not honor the market separation constraint, which must result in a more price-responsive import supply curve than one that would occur if the market separation constraint was honored. As discussed in BBW, this would tend to bias upward our estimate of the competitive benchmark price. Let IMP(P|h,d,m) be this average import supply curve for hour h of day-type d of month m as a function of the price P. The other input necessary to compute the competitive benchmark is price is the aggregate instate marginal cost curve for energy. BBW (2000) discusses in detail the methodology used to construct this

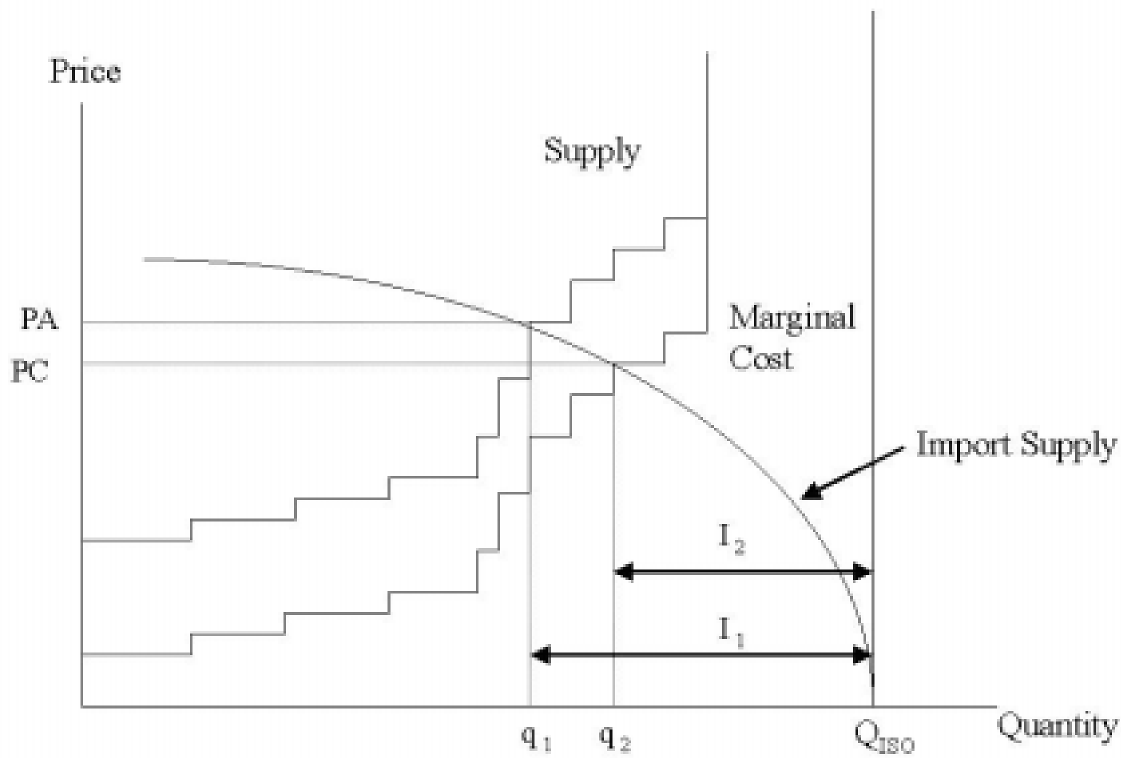
[8] Borenstein, Severin, Bushnell, James and Wolak, Frank, (2000) "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," August, available from http://www.stanford.edu/~wolak.

curve for a given hour. However, a major input to this process is the price of natural gas times the heat rate of each fossil fuel unit.. To account for changes in natural gas prices over the next two years, we propose to use the New York Mercantile Exchange Henry Hub monthly futures contract natural gas price as an estimate of the monthly natural gas price for each month during the two year market power mitigation period. This monthly futures price plus an estimate of the cost of transporting natural gas to the California border will be used as the monthly natural gas price entering into the process of computing the aggregate instate supply curve. Let QS_COMP(p,m) denote that amount that would be supplied by instate capacity under the competitive benchmark price during month m of the market power mitigation period computed as described in BBW (2000) using the natural gas forward price for that month. The competitive benchmark price, PC(h,d,m) in hour h of day-type d of month m of the market power mitigation period is the solution in P of the equation

$$\text{LOAD}(h,d,m) - \text{IMP}(P|h,d,m) = \text{QS\_COMP}(P,m).$$

Figure 4 provides a simple graphical illustration of this calculation. The top curve in the graph labelled ”Supply” is the actual bid supply curve in the hour. The curve labelled “Import Supply” is the import supply curve, IMP(P|h,d,m) in the above notation. The intersection of these two curves gives the actual market-clearing price, PA. The lower curve labelled “Marginal Cost” is the competitive benchmark supply curve, QS_COMP(P,m). The intersection of these two curves yield the competitive benchmark price, PC(h,d,m). This process can be repeated for the two day-types for all hours in the day for all 24 months in the market power mitigation period to yield P(h,d,m) for all months and two day-types and hours. This process could be easily built into a spreadsheet once the curves IMP(P|h,d,m) and QS_COMP(P,m) have been computed .

Figure 4: Sample Computation of Competitive Benchmark Price



There are a number of possible modifications to the process used to determine PC(h,d,m). Any modification that comes closer to obtaining a more accurate estimate of the perfectly competitive benchmark price in hour h of day d in month m of the two-year market power mitigation period should be adopted. Alternatively, any market participant should be allowed to offer any other forward contract price pattern for its QC(h,d,m,i) obligations during the two-year mitigation period, so long as the annual quantity weighted average price of this forward contract offering is below the quantity-weighted average price computed using the BBW (2000) competitive benchmark prices.

The Commission could also decide to set the value of PC(h,d,m) for all hours of the two-year mitigation period using some other mechanism that mitigates market power during the two year period. For example, the Commission could set a fixed value of PC(h,d,m) equal to $50/MWh for all hours, day-types and months.

For a variety of reasons, we believe that computing the forward contract price using our recommended methodology would yield an upward biased estimate of the competitive benchmark price for the two-year market-power mitigation period. First, the amount of imports into California during Historic Year were less than any previous 12-month period the market has operated, and are likely to be lower than those during the next two years. Second, in the BBW(2000) methodology, whenever they are required, assumptions are made which increase rather than decrease the competitive benchmark price. Nevertheless, we recognize that some market participant may feel that the requirement to offer forward contracts at these competitive benchmark prices may not allow them the opportunity to recover their annual production costs on a going forward basis. For this reason, our proposed market power mitigation plan offers an alternative to any market participant that does not wish to supply the required quantity of forward contracts over the two-year market power mitigation period.

Those market participants unwilling to offer the required quantity of forward contracts at these competitive benchmark prices will no longer be eligible to receive market-based rates for any of their sales of energy or ancillary services in the California market. Because the Proposed Order concluded that prices set through the PX and ISO markets are not just and reasonable during all hours of the year, a market participant should therefore be willing to offer sufficient market power mitigation measures if it would like to continue to receive market-based rates for sales of energy and ancillary services in California. This logic seems consistent with the previous Commission rulings cited above.

At this point, we should emphasize the importance of imposing this market power mitigation on the entire portfolio of a market participant, rather than on a unit-specific basis. As noted above, the logic underlying our mitigation plan follows from the Commission's process for granting market-based pricing authority. Market-based rates are granted at the level of a generation-owning entity within a given market rather that to a specific generation unit within a market. For this reason, market participants should be offered the choice of offering the two-year market-power-mitigation forward contract (not subject to refund) for the price and quantity combinations computed as described above, or file for cost-of-service rates for energy and ancillary services for all of its sales as a condition of making any sales into California. Those market participants electing to file cost-of-service rates for all of their sales into California would be required to bid a zero price for any quantity of energy or ancillary services they sell in the PX and ISO markets during the interim period before cost-of-service rates can be determined. These market participants would receive the resulting market prices for their sales subject to refund, once the appropriate cost-of-service rates have been determined. This requirement to bid a zero price into both energy and ancillary services markets is necessary to prevent these entities from exercising market power during this interim period.

To provide an additional incentive to market participants to elect to make these market-power-mitigated forward contracts available, the Commission could consider relieving sellers of all refund obligations for sales before December 31, 2000 in exchange for offering this market-power mitigated contract. Those firms electing to file for cost-of-service rates would still be subject to full refund liability. Our expectation is that even without this additional incentive, very few firms will elect to receive cost-of-service rates for all of their sales into California. The relief from refund obligations can be considered the "carrot" for getting them to offer these forward contracts, whereas the suspension of market-based pricing authority for all energy and ancillary services sales to California is the "stick." The combination of these two incentives should achieve the desired result, particularly if the Commission expands the scope of it efforts to determine whether refunds are warranted as recommended earlier in this report.

The Role of the CPUC in Market Power Mitigation Plan

Once all market participants have decided either to provide the market power mitigation forward contract for the two-year mitigation period or to make all of their future sales at cost-of-service based rates, the stage of the market power mitigation plan that involves the CPUC begins. For the purposes of this discussion, we assume that all market participants have elected to offer the forward contracts discussed above for the market-power mitigation period. Later we discuss the modifications necessary to include cost-of-service rates.

The availability of a sufficient amount of forward financial contracts at a known wholesale price for the next two years will allow the CPUC to set fixed retail rates for small business and residential customers over the two-year market power mitigation period. These forward contracts could then be offered to all load-serving entities according to the following algorithm so that each load-serving entity would have the opportunity to hedge the wholesale energy purchases necessary to meet its expected retail electricity sales to these customers using these forward financial contracts.

Each load-serving entity would file with the CPUC the total quantity of retail sales it made to small business and residential customers during the Historic Year. For the three IOUs this process would be straightforward. It is total amount of load provided under the rate schedules used to compute the fraction of total ISO load consumed by small business and residential customers for each IOU. Each of these fractions where used to compute the estimate of the statewide fraction of small business and residential customers, X(m), described earlier. The remaining load-serving entities should be able to supply this information broken out in a similar manner. Let QR(j) equal the annual quantity of sales to small business and residential customers (as defined by the CPUC) made by load-serving entity j during the Historic Year. Let QR(market) equal the sum of the QR(j) over all load-serving entities in the California ISO control area. Compute the ratio of the statewide level of annual load consumed by small business and residential customers. Let WR(j) = QR(j)/QR(market) equal this ratio. This ratio, QR(j)/QR(market), is the share of the total quantity of forward contracts offered that load-serving entity j can purchase. Each of these load-serving entities would have the opportunity to purchase a forward contract quantity in each hour equal to this share, WR(j), times the total quantity of contracts offered in that hour at the forward price for that hour of P(h,d,m). Mathematically, this maximum purchase quantity for load-serving entity j is WR(j)*X(m)*LOAD(h,d,m). Any load-serving entities purchasing a non-zero quantity of these forward contracts would then be obligated to offer to supply retail electricity to small business and residential customers at the fixed default provider rate determined by the CPUC.

Because the definition of small business and residential customers used throughout this plan maps directly to the rate schedules currently offered by each of the IOUs, the CPUC can use its usual rate-making process to determine this fixed default provider retail rate by taking the two-year quantity-weighted average forward contract price as the relevant average wholesale energy price for the two-year period. This rate-making process should result in default provider rates for each rate schedule offered to small business and residential customers by each IOU service territory. Besides the obligation to offer these default provider rates to all small business and residential customers, any purchaser of these forward contracts, including the 3 IOUs should be allowed to offer any other retail-pricing plans to these customer classes they find profitable. The availability of this default provider rate protects these two customer classes from wholesale energy market power during the two-year market power mitigation period. However, in order to provide the maximum incentives for the development of price-responsive retail demand from these customer classes, all load-serving entities (including the IOUs) should also be allowed to offer whatever other pricing plans they would like to these customers without CPUC approval. This retail pricing freedom will provide very strong financial incentives for these customers to take on wholesale market price risk in exchange for lower annual average prices if they manage to alter significantly their consumption in response to hourly wholesale prices. Competition among the load-serving entities to provide these pricing plans will lead to the most rapid development of a significant amount price-responsive final demand for each customer class. This helps to achieve our plan's goal of rapidly expanding the amount of price-responsive demand in the California market.

Each market participant is then obligated as a condition to maintain market-based rates in the PX and ISO markets to have a standing offer for certain time period to sell their market-power mitigated forward contract obligation for energy over the next two years. We would exempt new generators, and new capacity from existing generators from these requirements, in order not to dilute the incentives for new generation investment.

One way to sell these forward contracts would be to have the PX, ISO or CPUC run an open procurement process for a certain length of time before the start of two-year market power mitigation period. For example, if the market power mitigation period starts on March 1, 2001, then one of the three entities could run the procurement process during the first-weeks of the month of February 2001. Slightly before this time period, each load-serving entity would submit the data necessary for the CPUC to certify the share of these forward contracts each load-serving entity can purchase. Given this CPUC-certified share, the load-serving entity would then be able to buy a quantity of forward contracts equal to this share of the total forward contract quantity in each hour of the two-year period at the price, PC(h,d,m), that is relevant for that hour, day-type and month. After this two-week period, any unsold contract quantities would be given back to the market participants that offered them in proportion to the value of their market power mitigation fraction, which is also the proportion of the total hourly quantity of contracts they originally supplied.

At this point we should comment on our choice of the duration of these forward contracts. Because the current supply conditions in the California market and WSCC are likely to persist for at least the next two years, we selected this time period for our market power mitigation period. Longer periods of time may provide more protection against up-side risk in wholesale prices, but the downside wholesale price risk that may result from the much-needed new investment in generation and transmission capacity out-weighs the need to protect consumers from the exercise wholesale market power for a longer period of time. Longer term contracts beyond this two-year period have a significant risk becoming “stranded” because of lower wholesale prices that result from new entry and lower input fuel prices in future years. A contract duration of two years appears to balance our goals of providing the strongest incentives possible for the most rapid development of price-response retail demand and new generation capacity investment in California against our primary goal of protecting consumers against high wholesale prices through a time-period when limited new capacity will come on line.

It is important to note that we have not discussed a market power mitigation measure for large industrial or commercial customers. These customers are already active participants in the wholesale market, and if they are not, they have the financial sophistication and clout to become active participants. In addition, they are the entities that best able to manage the spot market risk because many of them are ideal candidates for constructing co-generation facilities or making use of modern technology to smooth their energy consumption within the day. In addition, many of these entities have very attractive industrial sites located close to load centers where they could construct power plants at significantly less cost than at a greenfield site. Finally, these entities also have the financial resources to ensure that the siting of new generation capacity in California proceeds as rapidly as possible during the next two years. These entities should also be particularly facile at finding new or not previously exploited energy sources outside of California to meet their energy needs during the interim period. For all of these reasons, we see little need to provide explicit market power mitigation to these entities. Such a measure would unnecessarily dull their financial incentive to solve as rapidly as possible the tight electricity supply conditions currently in the California market and fail to achieve our goal of increasing the amount of generation and transmission capacity in California as rapidly as possible.

Assuming that all California market participants agree to provide the forward contract quantities necessary to protect small business and residential consumers in California at the prices described above, all market participants in the California would be eligible to receive market-based rates for all sales of energy and ancillary services in the PX and ISO markets. The ISO should continue to maintain the current damage control, hard price cap on both energy and ancillary services. Because of the existence of these market power mitigation measures described above and the increased cost of natural gas, and the necessity of providing strong economic incentives for new investment in generation and transmission capacity, the ISO should consider raising these price caps as soon as possible. A higher price cap should allow the ISO sufficient flexibility to attract the necessary power to California during tight system conditions in the WSCC during the next two summers. Because residential and small business consumers are protected from spot price fluctuations during the two-year market power mitigation period, raising the price cap will increase the attractiveness of the California market to new generation capacity without harming these customer classes.

We now discuss how our plan can be modified to account for market participants that elect to only make cost-of-service sales into California. The California ISO will first provide an estimate of the annual total quantity of energy that it will purchase from this market participant. This quantity of energy will be included in the quantity of energy available to be purchased by load-serving entities in the market-power-mitigated forward-contract procurement process. The CPUC should allow all load-serving entities to purchase a fraction of all of the expected cost-based energy sales into the ISO at the average cost of these sales. This fraction can be no greater than that load-serving entity's value of WR(j) described above. The CPUC can still set the default provider rate described above, but subject all load serving entities to refunds or future rate increases if the actual average cost of energy from these cost-of-service sales differs significantly the forecasted average costs used to set the default provider rates.

At this point we should urge the Commission make the cost-of-service alternative sufficiently unattractive in other dimensions to sellers into the California market so that they will elect to supply the market-power-mitigated forward contracts and retain market-based pricing. Any market power mitigation plan that combines cost-of-service regulation with a competitive market is likely to lead to market outcomes that result in same level of market power exercised on an annual basis, but results in significantly less hours with extremely high spot prices. However, as discussed earlier, the goal of our proposed measure is to mitigate market power in the spot market to achieve the lowest possible average wholesale prices consistent with financial viability of the industry. For this to occur there must be an active demand-side of the market. An active demand-side is unlikely to develop unless there is the prospect of high spot electricity prices that can be avoided through demand price-responsiveness. With a large fraction of the market covered by market-power-mitigated forward financial contracts, high spot prices can provide the necessary price signals to attract new generation capacity to California and investments in demand price-responsiveness technologies without imposing significant financial hardship on small business and residential consumers.

On the other hand, imposing a load-differentiated price cap, where the market is subject to different price cap levels depending on the ISO's forecast of total system load suffers from a number of shortcomings relative to our proposed market power mitigation plan. First, a load-differentiated price cap does not alter the incentives generation unit-owners have to exercise market power in the spot market. It only limits the maximum price that a generator can receive during certain forecast system load conditions. In this way, the load-differentiated price cap combines the worst properties of cost-of-service pricing and market-based pricing. The load-differentiated price cap sets a generous upper bound on the maximum cost of serving load for each range of forecast system conditions. Therefore this scheme can provide no guarantee of protection from the exercise of market power that raises prices some significant percentage above competitive levels (but still below the load-differentiated price cap) for large fraction of hours of the year. In addition, a load-differentiated price cap provides limited incentives for the development of the forward markets necessary for the long-term success of a competitive electricity market. As discussed earlier in this report, price spot volatility increases the value of forward contracts, because they allow the purchaser to avoid this risk. With very little wholesale price volatility, as is the case under the load-differentiated price cap, even if annual average wholesale prices are high, there will be very little demand for forward contracts. This price cap scheme also provides very limited incentives for the development of price responsive final demand, because there is little risk of very high wholesale prices. Although, a load-differentiated price cap does provide short-term protection from the exercise of some forms of market power, it provides few incentives for the development of the necessary market mechanisms that will eventually allow its removal. Consequently, if a load-differentiated price cap is implemented, it is unlikely that market conditions will ever get to the point that it can ever be removed.

A final complication with a load-differentiated price cap arises when it is applied to California in isolation. There could be any number of hours during the year when the load-differentiated price cap in California is relatively low, but there is a large demand for power elsewhere in the WSCC at greater than this California load-differentiated price cap. The California ISO would then be faced with the problem of attracting sufficient energy to the California market. The problem of California generation unit owners scheduling energy outside of California and having it sold back into California at higher price as an out-of-market call would arise again. This would now occur in lower demand periods than it did during the Summer of 2000, because of the load-differentiated price cap. The Commission could decide to impose the load-differentiated price cap for the entire WSCC. However, this would immediately give rise to the question of what load level would determine what price cap. The most plausible alternative would be to set the WSCC-wide price cap using a forecast of WSCC-wide load. The administrative problems associated with setting a price cap for the entire WSCC based on a forecasted load for the entire region are likely to be quite great. The price cap would have to set equal to at least the cost of the highest cost unit expected run that day in the WSCC. This price cap is likely to be significantly greater than one based on the California market alone, thus rendering this load-differentiated WSCC-wide price cap significantly less effective at mitigating market power.

Market-Power-Mitigated Forward Contracts for Ancillary Services

The final issue to be addressed is how to implement market-power mitigated forward contracts for ancillary services. To compute the forward contract quantity for each market participant in each ancillary services market, proceed in the same manner as was done for the energy market. This process yields a market-power-mitigation fraction for each market participant in each ancillary services market that is equal to the fraction of total sales in MW of that ancillary service by that market participant during the Historic Year.

The next step involves computing month, day-type, and hour shapes for the total requirements for ancillary services for each month and day-type for the Historic Year, computed in the same manner as the load shapes given in Figures 1 and 2. Because ancillary services are billed to loads in proportion to their actual energy consumption we can use X(m), our estimate of the fraction of total system load in month of the Historic Year that is consumed by small business and residential customers to compute the forward contract obligation for each ancillary services for each market participant.

The forward contract obligation for each month, day-type and hour for each market participant in each ancillary service is equal to the ancillary service-specific market-power-mitigation fraction for that market participant, times the average market demand for that ancillary service in that month, day-type and hour, times X(m) for that month.

The final step of the process of defining each ancillary services forward contract is computing a competitive benchmark price. The process is complicated by the fact that all ancillary services, including Regulation pay a generation unit owner for supplying energy in real-time, so the primary cost of ancillary services, assuming the market-participant's unit is not called to provide energy in real-time is the opportunity cost supplying energy in real-time. It is difficult to imagine any significant direct costs that vary with the quantity of ancillary services provided. Therefore, we would expect competitive benchmark prices for ancillary services to obtain only when competitive benchmark prices occurred in the California energy market. As noted in the September 2000 MSC Report there was a 9 month period in the California electricity market when weighted average prices over that period were close to BBW weighted average competitive benchmark price. Consequently, we select the 12-month period that the California energy market has operated with the lowest value of the BBW measure of market performance as the competitive benchmark period for computing the competitive benchmark prices for ancillary services. From Table 1 of the September 2000 MSC Report, this 12 month competitive benchmark period is October 1, 1998 to September 30, 1999. For this competitive benchmark period, we compute PC(h,d,m,k), the competitive benchmark price for ancillary services k, in hour h, of day-type d, during month m as the average of the hourly quantity weighted average NP15 and SP15 prices of ancillary service k prices over all hour h's and day-type d's in month m. Repeating this procedure for all months and day-types for all ancillary services yields a value of PC(h,d,m,k) for all hours and day-types and months for each ancillary service. This process would be extremely straightforward to implement.

Once these ancillary contract quantities have been determined for each market participant and ancillary service, they could be sold through the same mechanism and in the same proportions as the forward contracts for energy are sold to the load-serving entities. Any remaining unsold forward contracts could be returned to the sellers using the same algorithm described earlier for the energy market.

We should note that if our recommendations described earlier and outlined in detail in the September 2000 MSC Report for solving the ISO's under-scheduling problem are not implemented, the above procedure for computing the competitive benchmark value of ancillary services prices may under-estimate the competitive benchmark price of Regulation Reserve. This is because the ISO does not use its Regulation capacity in the hour so that the net energy sold from this capacity is approximately zero. Instead, the ISO uses Regulation to manage the large amount of deviations from schedule that result because the lack of a real-time trading charge of the form described earlier on loads and generation for all energy imbalances regardless of their cause—instructed or uninstructed deviations. With a uniform penalty on all real-time deviations on generation and load, regardless of their source, forward schedules will become much more accurate forecasts of actual real-time production and consumption, so that the ISO can reduce its demand for regulation and use it to only to manage second-to-second imbalances in the hour so that the net energy supplied within an hour from a unit providing Regulation is zero. However, if the ISO continues with its current Replacement Reserve penalty scheme or a real-time trading charge that distinguishes between uninstructed and instructed deviations, this increased demand for Regulation Reserve will be necessary to manage the imbalance created by market participants attempting to use their portfolio of loads and generation units to cause profitable real-time instructioned deviations for some of its units. This sort of activity, although it is profitable for individual market participants, is detrimental to system reliability and increases the demand and therefore the price for Regulation Reserve. For this reason, as well as others mentioned in the September 2000 MSC Report, we strongly encourage the Commission implement our recommendations for solving the ISO's under-scheduling problems.

Concluding Observations

With this market power mitigation plan in place, if high spot electricity and ancillary services prices occur, California's small business and residential customers will be protected during the two-year market power mitigation period. During this period we hope that significant new generation and transmission construction to be completed. Therefore, by the end of the market power mitigation period, there should be sufficient new supply of capacity and imports into California so that load-serving entities can sign forward contracts for future delivery at attractive prices. This voluntary availability of competitively-priced forward contracts is less likely to happen if during the market power mitigation period spot energy and ancillary services prices are not allowed to reach the levels necessary to attract these hoped for new suppliers to the California market with sufficient frequency to make these new investments financially viable. Anything but a relatively high damage-control price cap on the energy and ancillary services markets will dull the price signals essential to attract new generation and transmission capacity, as well as new demand-side management technologies and retail pricing patterns. If a market power mitigation plan is enacted that significantly dulls these incentives, then there will be a continued need for market power mitigation measures into the foreseeable future, as well as a continued need for costly regulatory intervention to insure sufficient energy is supplied into California to meet its rapidly growing demand.

In closing, it is important to note that a generating facility providing exactly the same amount of energy in each hour of the year in a competitive regime as it did in the regulated regime should face the same risk of an outage in both regimes, assuming that it properly maintained. The same statement can be made for the transmission grid. Consequently, under these assumptions, the same risks of system failure exist in both the competitive wholesale market regime and the former regulated regime. Rather than assigning these risks based on regulatory hearings and procedures, as was done in the further regulated regime, a competitive regime offers the opportunity to assign these risks to those market participants best able to bear them. Prices that generators receive and customers pay is the mechanism used by a competitive market to allocate risks. Consequently a potential source of cost savings from competitive markets is that these risks are allocated to those entities that can manage them at the lowest cost, rather than by administrative rules.

The one lesson from the experience from this summer in San Diego is that retail and small business customers are not yet ready or able to take on this risk because of, among other things, the lack of the necessary retail market infrastructure such as hourly meters and the billing systems and other revenue cycle services necessary for low entry barriers into the retail market. With the market-power-mitigated forward contract that we recommend in place, these customers classes are protected from wholesale market risks for a sufficiently long period of time (e.g., two years) to put in place the necessary retail market infrastructure for them to begin to take on these risks if they find it in their financial interest to do so. When these two-year forward contracts expire, those retail and small business customers willing to take on wholesale price risk and can do to so for their own benefit and for the benefit of the competitiveness of the California wholesale electricity market. During the coming two-period, a competitive market subject to as little arbitrary regulatory intervention as possible on the level and volatility of wholesale energy and ancillary services prices is necessary to provide the maximum incentives for workably competitive wholesale energy and ancillary services markets to develop by the end of the market power mitigation period. Because small business and residential customers are protected from wholesale market price risk during this period, only those market participants with the ability and financial resources to manage this price risk will need to bear it, and over time market processes will allocate these risks to those entities best able to bear it at the lowest cost possible, with the end result lower average wholesale prices. It is important to emphasize that the subsequent period with lower average wholesale prices could contain a number of hours with extremely high wholesale prices which causes shifts of demand away from these hours and provides strong signals for all suppliers in the WSCC to bid into the California market.

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