Alternatives to Implementing an Locational Marginal Pricing Market
by

Frank A. Wolak, Chairman
Market Surveillance Committee of the California ISO

Draft: August 25, 2004

1. Introduction

The seller's choice long-term contracts signed by the California Department of Water Resources have the potential to create a significant liability for California consumers under a wholesale market design that uses Locational Marginal Pricing (LMP). Consequently, there is an interest among California policymakers in developing alternatives to a LMP market design that limits this liability. The purpose of this memo is to outline two possible alternatives. The first builds on the fact that during the first two years of operation, from April 1998 to April 2000, the California market achieved an average market performance comparable or superior to the performance of other U.S. markets over the past six years. Modifications to the current market design are proposed so that it will achieve the performance of the California market during its initial two years into the foreseeable future. The second alternative builds on the experience of international electricity markets to achieve a market design that provides California ISO operators with sufficient flexibility to operate the system in real-time without requiring costly changes in the current market design. Both of these proposed market designs can be implemented as transitional measures until the seller's choices contracts expire and an LMP market can be implemented. However, if these market designs are accompanied by the appropriate changes in California's procurement and transmission expansion policies, either could be made permanent.

All of the proposed market designs, including the ISO's current LMP design, require the ISO and market participants to incur transition costs. To be justified on an expected cost versus expected benefit basis, the discounted present value of the expected benefits associated with a market design change must exceed the discounted present value of the expected costs associated with that market design change. Among those market design changes with positive expected net present value, a reasonable decision rule is to choose the one with the largest net present value. Because the seller's choice contracts have such a large potential cost to California consumers under a LMP market design and there are significant software costs associated with implementing this market design, an expected cost versus expected benefit decision criteria could lead California to choose an alternative market design unless the large potential costs of the seller's choice contracts are mitigated through regulatory intervention by the Federal Energy Regulatory Commission (FERC). The two alternatives proposed below build on the existing market design to limit these transitional costs. Market rule changes to improve the efficiency of the real-time market are also proposed.

The remainder of this memo first summarizes the lessons from US and international experience for a successful spot market design. The next section presents the first alternative market design that attempts to improve the performance of the California market with minimal changes in the current zonal design. The third section describes a second modification to the current design that uses the lessons from international experience to provide California ISO system operators with increased real-time locational pricing options to operate the system within the context of the current California ISO forward market.

2. Lessons from International Experience

The first major lesson from both US and international experience with electricity market design is that it is extremely difficult to create a competitive bid-based spot market for electricity. A number of technological and institutional factors make this process extremely challenging. Supply must equal demand at every instant in time and each location of the network. Electricity is very costly to store and production is subject to extreme capacity constraints in the sense that it is impossible to get more than a certain amount of energy from a given generation facility in an hour. Delivery of electricity must take place through a potentially congested transmission network. How electricity is priced to final consumers by state regulators throughout the US makes the wholesale demand for electricity extremely inelastic, if not perfectly inelastic, with respect to the wholesale price. The technology of electricity production historically favored large generation facilities, and in all markets throughout the US the vast majority of these facilities are owned by a relatively small number of firms. Generation capacity ownership also tends to be concentrated in small geographic areas of these regional wholesale markets.

All of these factors make wholesale electricity markets substantially less competitive the shorter the time lag is between pricing and delivery of the electricity through the network. Typically, there are a small number of suppliers or even one supplier able to meet an unanticipated real-time energy need at a given location in the transmission network. Consequently, this supplier can effectively be a monopolist to supply this local energy need. The further in advance of delivery the consumer of this electricity knows of this energy need, the more suppliers can compete to provide it. This logic suggests that only those purchases that are absolutely necessary to make in the spot market should be made. The vast majority of system demand should be purchased far in advance of the delivery. If these forward market purchases are structured as fixed-price forward contracts for a fixed amount of energy in the hour, they can also have very beneficial impacts on the competitiveness of shorter-term energy markets. As discussed in Wolak (2000), forward contract holding by a supplier make it unilateral profit-maximizing to bid more aggressively in the spot market. Moreover, Wolak (2000) also emphasizes that forward contract holdings by one supplier can make it unilaterally profit-maximizing for other suppliers to bid more aggressively, regardless of their own forward contract holdings. The most successful wholesale electricity markets in the world, as judged by the competitiveness of their spot markets, tend to be those with where only a very small fraction of the total amount of electricity consumed is actually purchased on the spot market.

This logic argues in favor of focusing the market design process on purchasing the forward market commitments necessary to meet actual load obligations at the locations in the network where the load exists, leaving only those energy needs that cannot be forecast in advance for the spot market. If properly structured, forward market commitments make both the firm that has the forward market obligation and other suppliers more aggressive participants in the spot market. This leads to lower and less volatile spot prices. The larger the fraction of final demand purchased in the forward market, the less exposed consumers are to spot price volatility. The more closely forward market purchases are matched to the final demand at each location in the transmission network the less need there is for spot market purchases. Consequently, a less costly strategy, both in terms of overall energy costs and minimizing the likelihood of system reliability problems is to purchase the obligations to serve real-time energy needs at each location in the network as far in advance as possible.

The second major lesson from international experience with electricity market design is that local market power problems arise in all wholesale electricity markets, regardless of the congestion management mechanism used. Local market problems arise in the wholesale market regime because the existing transmission network in virtually all parts of the US is very poorly suited to support the geographic extent of competition in electricity supply required to discipline the spot market bidding behavior of all market participants given the concentration of generation capacity ownership in US wholesale markets. The existing transmission network in the US was largely built over the past 50 years, a period dominated by vertically integrated investor-owned utilities. Moreover, over the past ten years, as the vertically-integrated utility regime has given way to wholesale markets, there has been a significant decline in investment in transmission expansions and upgrades throughout the US relative to the growth that occurred during previous decades.

Particularly, around large population centers and in geographically remote areas, the vertically integrated utility used a mix of local generation units and transmission capacity to meet the annual demand for electricity in the region. Typically, this utility supplied the region's baseload energy needs from distant inexpensive units using high-voltage transmission lines. It used expensive generating units located near the load centers to meet periodic demand peaks throughout the year. This combination of local generation and transmission capacity to deliver distant generation was the least-cost strategy for serving the utility's load in the former regime.

The transmission network that resulted from this strategy by the vertically integrated utility creates local market power problems in the new wholesale market regime. Under the new wholesale market regime, the owner of the generating units located close to the load center may not own and certainly does not operate the transmission network. The owner of these local generation units may not even be the load-serving entity (LSE) for that geographic area. Unless the owner of these local generating units is subject to state-level regulation of its sales, the firm now earns higher profits by selling all output from the units (that has not been pre-sold under a long-term forward contract) at the highest possible price in the wholesale market. This price depends on the bids this firm submits to supply energy. Consequently, during the periods when this firm knows that output from its units is needed to meet local demand, it is profit-maximizing for the unit owner to bid whatever the market will bear for any energy supplied to the wholesale spot market from these units. This result occurs regardless of the locational pricing scheme used by the ISO.

It is important to emphasize this point. Absent local market power mitigation in a LMP market, the bid of the unit or units with local market power would have to be taken. This implies that the LMP at these locations in transmission network would be at or above the bids of these firms. Absent local market power mitigation in a zonal market design, the suppliers with local market power are paid as-bid for the necessary energy. Which market design leads to higher overall wholesale energy costs to consumers depends on a number of factors, but there are two important points to emphasize. First, there are circumstances when a zonal market design would lead to lower wholesale energy costs and circumstances when a LMP market design would lead to lower wholesale energy costs. Second, in the near-to-medium term, no wholesale market design is likely to lead to lower wholesale energy costs than those that existed under the vertically-integrated monopoly regime without an effective local market power mitigation mechanism. Given the configuration of the existing transmission network and the geographic distribution of generation capacity ownership in all US wholesale markets, the frequency and magnitude that certain market participants have possess substantial local market power implies that if left unmitigated, these suppliers could earn enormous profits by exploiting it.

Effective local market power mitigation (LMPM) is a necessary component of any wholesale market design. For the same LMPM mechanism under a zonal versus nodal market design there is also no general conclusion about which market design yields lower average delivered prices of electricity. The New Zealand electricity market provides a graphic illustration of this point. New Zealand is the only LMP market currently operating outside of the US. During the periods June to September of 2001 and 2003 it experienced high wholesale electricity prices for much the same reason that California experienced very high prices during the period June to September 2000--insufficient forward contract coverage by a number of LSEs of their obligations to final consumers. These facts raise the question: What are the benefits from adopting an LMP market design? This is the final lesson from international experience with electricity market design.

An LMP market design provides the system operator with many more tools to operate the system in real time. Under an LMP design, the system operator has the ability to set a different price for electricity at each location in the transmission network. In contrast, under a zonal market design, the system operator can only set a single price for the entire zone. This flexibility is particularly valuable when the system operator needs to have certain generation units increase their output and other decrease their output within in the same time interval. This can be seamlessly handled in the LMP market by reducing the nodal prices for the units that the system operator needs to reduce their output and increasing the nodal prices for units that system operator needs to increase their output. How much the system operator must reduce or increase a nodal price is determined from the bid curves submitted by each generation unit.

Under a zonal market design, the system operator must resort to other means to move generation units in same congestion zone in different directions within the same time interval. This can be accomplished in a number of ways. For example, all market participants could receive the zonal price for all of their output in the hour if they obey the dispatch instructions issued by the system operator within that hour. To provide additional incentives to obey dispatch instructions, market participants that are out-of-merit within the zone also could be receive an uplift payment. For example, if all but one or two units in a zone are increasing their output within the hour, the two remaining units could be paid an administratively determined uplift payment to compensate for reducing their output to maintain system reliability.

If the wholesale market has an effective LMPM mechanism, the additional flexibility afforded the system operator under an LMP market allows virtually any transmission network configuration to be reliably operated. The system operator only needs to vary the prices at each location in the network to ensure that all the generation units in the system are operated at the levels necessary for demand to equal supply at all locations in the network. The reduced locational pricing flexibility available to the system operator under a zonal market design limits the range of transmission network configurations that can be reliably operated without additional regulatory backstops either in the form of additional transmission capacity within the zone or in the form of reliability must-run generation units within the congestion zone. Attempting to run a zonal market design without these additional regulatory safeguards can degrade system reliability.

It is important to emphasize that neither a nodal or zonal market design eliminates the need to run expensive generation units for local or system-wide reliability reasons. The configuration of the transmission network and geographic location of available generation units and loads are important inputs into this decision. An LMP design explicitly minimizes the as-bid dispatch costs of meeting all locational energy needs. Zonal designs typically pay out-of-merit suppliers (within the congestion zone) as-bid for decremental and incremental energy. There are circumstances when the LMP approach will lead to lower average prices to consumers and circumstances when the zonal market approach will lead to lower average prices. The advantage of the LMP design is still the flexibility that it affords system operators in providing location-specific price signals to generation unit owners to provide the necessary energy at each location in the network to meet the geographic distribution of load throughout the transmission network.

A very important longer-term benefit of an LMP market design is that it provides transparent locational price signals for potential entrants considering whether to construct new generation capacity. If a supplier locates in a generation-rich area, it will receive a low locational price. Suppliers locating in a generation-scarce area will be rewarded with a high locational price. In under a zonal design, a new entrant will receive the zonal price regardless of where they locate in the zone, even if it is a generation rich segment of the zone. Consequently, under a zonal market design there is must less need for a pro-active transmission expansion policy, because suppliers receive a price that reflects the as-bid costs of withdrawing electricity at their location in the transmission network. In contrast, a zonal design without a pro-active transmission expansion policy can result in new entrants locating where there is easy access to input fuels or cooling water, even through there may be insufficient transmission capacity to support interconnection at this location within the zone. This logic implies that a zonal market design requires a more pro-active transmission expansion policy and more prescriptive new generation inter-connection policy. This forward-looking transmission expansion policy is necessary to ensure that new entrants build generation capacity at locations in the congestion zone where the energy can actually be delivered to final demand. Under an LMP market design, a new entrant has a unilateral incentive not to enter at these locations because they will depress the LMP that they receive for the energy they provide.

These lessons from international experience form the basis for two alternative market designs. The first proposed market design requires only minimal changes in the existing market design. The second attempts to capture some of the benefits of the LMP market design described above, without explicitly adopting an LMP market.

3. Modified Zonal Market Design

The goal of this alternative market design is to make only those changes to the current California market design necessary to operate the system reliably. This market design recognizes the need to purchase energy in forward market in order to limit market power in the real-time and short-term forward markets. It adopts a LMPM mechanism similar to the PJM market. It explicitly recognizes that a zonal market may not be able to operate as reliably a LMP market without either additional regulatory safeguards in each congestion zone or additional transmission capacity within each zone. This design also recognizes that a more pro-active transmission expansion policy and more prescriptive new generation interconnection policy are needed for a successful zonal market design.

This market design would require the California Public Utilities Commission (CPUC) to enact a procurement policy that requires California LSEs to purchase virtually of their retail energy needs in forward contracts that are deliverable to final consumers. Rather than require least-cost procurement assuming an uncongested transmission network, the CPUC must recognize that transmission congestion necessitates calling upon higher cost generation units located closer to load centers. The LSEs must be provided with incentives to purchase this energy in advance, if it is needed to meet its retail load obligations. A straightforward way to enact such a policy would be to allow the LSEs to pass-through in retail rates the cost of procuring a given quantity of energy under a long-term contract, but all or a significant fraction of the costs associated with delivering this energy to final consumers would be borne by the LSE. In particular, if the LSE decided to purchase its required energy from a distant generation unit owner, it would receive no or only partial reimbursement for the re-dispatch costs associated with calling on more expensive local generation units because this energy cannot be delivered in real-time.

For the reasons given in the previous section, an essential feature of any successful market design is a LMPM mechanism. If California decides to move forward with an LMP market design, an effective LMPM mechanism is crucial to the success of this market design. For this reason, the ISO's proposed LMPM mechanism for its proposed LMP market should be adopted for this alternative market design. The ISO has proposed a version of the PJM LMPM mechanism, where suppliers taken out of merit order in one of three regions of the PJM market are subject to bid mitigation. This mechanism could easily be applied to California ISO's real-time market. At the close of the day-ahead scheduling process, the ISO operators could determine those units deemed to possess local market power in the real-time market, because they very likely to be taken out of merit order in one of the three California ISO congestion zones in the real-time market. These units would then be paid as-bid for the incremental and decremental energy they provide out-of-merit in the real-time at their filed variable costs.

Because zonal a market design pays all energy sold in the same congestion zone the same price, the transmission network within in the zone should have sufficient capacity so that all generation units in that congestion zone are approximately equally effective at serving load within that zone congestion. However, the transmission upgrades necessary for this to be the case will take a number of years to site and construct. In the meantime, the ISO can rely on local generation facilities to provide services equivalent to the additional transmission capacity. In particular, the ISO should increase the number of reliability must-run (RMR) units in the California ISO control area. During the first 18 months of operation of the California market, there was close to 15,000 MW of RMR capacity in the California ISO control area. Following the summer of 1999, the ISO decided to significantly reduce the amount of RMR capacity, particularly in the Southern California. To compensate for a transmission network poorly suited for California's zonal market design, the ISO should significantly increase its current RMR capacity. These generation units will provide similar services to additional transmission capacity, until this transmission capacity can be constructed.

The ISO should sign enough RMR contracts so that once RMR pre-dispatch instructions have been issued for each hour of the following day, the ISO operators have a high degree of confidence in operating an unconstrained energy market in each congestion zone for the vast majority of hours of the following day. Stated differently, the ISO should purchase sufficient RMR capacity, so that the incidence of intra-zonal congestion throughout the year is small fraction of the annual cost of wholesale energy in California ISO control area. Precisely, how much additional RMR capacity is needed and where in the ISO control area is needed, is unknown. The Department of Market Analysis could work with Market Operations to formulate plan for designating RMR units to achieve these goals.

The final aspect of the proposed alternative design becomes more relevant the longer this design is expected to be used. For this design to be successful over the longer term, the ISO and CPUC must adopt a pro-active transmission expansion plan that recognizes the need to have sufficient transmission capacity in each zone to make all generation units in that zone approximately equally effective at serving load in that zone during the vast majority of hours of the year. The ISO and CPUC must also adopt a new generation inter-connection policy that recognizes that this standard for transmission expansion underlies a successful zonal market design. Before approving the interconnection of a new generation facility at a given location in the network, the ISO must ensure that the criterion of approximately equal effectiveness at meeting load within the congestion zone must apply to all units in the zone after the new generation unit inter-connects to the transmission network.

4. Increasing System Operator Flexibility with Zonal Paradigm

The second market design modification builds on the experience of other international markets, specifically, the New Electricity Trading Arrangement (NETA) in the England and Wales electricity market in order to achieve increased system operator flexibility within the context of a zonal market design. This design would adopt all of the measures associated with the previous alternative market design, in addition to the following. To give the ISO operators greater flexibility in dispatching generation units in real-time and to provide strong incentives for LSEs and generation owners to avoid purchases or sales in the real-time market, this design would adopt a balancing mechanism similar to the one that exists in the NETA.

This balancing mechanism operates as follows. All generation unit owners that receive dispatch instructions from the ISO operators in the real-time market would be paid as-bid for the instructed amount of incremental or decremental energy they provide. All loads that consume more than their final schedule would pay the quantity-weighted-average price paid to all generation units that receive incremental dispatch instructions within that time interval. All generation units the supply less than their final schedule would also pay for the difference between their final schedule and their actual output at this same quantity-weighted-average price. For example, if three generation units received the following dispatch instructions, 50 MWh at a price of $50/MWh, 40 MWh at a price of $100/MWh and 10 MWh at a price of $200/MWh, then all under-scheduled demand and under-scheduled generation would pay $85/MWh their real-time energy needs, which is the quantity-weighted average of the prices paid to all incremental dispatch instruction issued by the ISO.

For generation unit owners receiving decremental instructions, a similar mechanism would apply. All generation units that receive decremental dispatch instructions would sell back energy as-bid. All loads that consume less than their final schedule could sell this energy back at the quantity-weighted average price of all decremental energy dispatch instructions. All generation unit owners that supply more than their final schedule would receive this price for the energy they provide. Each time period there would be two prices for the entire California ISO control area—the average incremental energy price and the average decremental energy price. This balancing mechanism would achieve the goal of providing the ISO operators with the same level of locational pricing flexibility available under an LMP market, yet set only a single decremental and incremental price of energy for each time period. This mechanism would also provide extremely strong incentives for market participants to avoid being out of balance relative to their final schedule, which would further increase the system reliability.

5. Concluding Comments

This document has proposed two alternative market designs that attempt to improve on the existing market design without having to incur the substantial software and other transitional costs or the seller's choice contracts obligations that would exist under a LMP market design. Many of the attractive features of a LMP market can be captured under the current ISO market design, subject to the above modifications. Moreover, if the ISO and CPUC embark on a procurement policy that rewards long-term contracts for energy that can be delivered to final consumers and a transmission expansion plan and RMR policy that pre-commits to making all non-RMR generation units in each congestion zone equally effective at meeting load within that zone, then the existing zonal design can be viable as a market design into the foreseeable future.

It is important to emphasize that zonal market designs are far more common than LMP designs internationally. Zonal designs exist in the three markets where consumers have achieved the greatest benefits from wholesale electricity market re-structuring—the United Kingdom, Australia and the Nordic countries. Because of geography, the legacy of the former state-owned monopoly regime and a regulatory framework that encourages transmission expansion (particularly in the United Kingdom), these markets have met the criteria of having sufficient transmission capacity within each congestion zone to make all generation units in that zone approximately equally effective at meeting loads in that zone a large fraction of the hours of the year. These markets provide strong empirical evidence that the two alternative market designs proposed above can provide California consumers with significant benefits without having to incur the substantial costs of implementing a LMP market, so long as California policymakers recognize the need for procurement policies and transmission expansions policies that support these market designs. As noted above, the strength of an LMP market is that the system can reliably operated and under a wider range of procurement policies and transmission expansion policies. However, as also noted above, the costs to California consumers are likely to be extremely high without regulatory intervention by FERC to address the seller's choice contracts liability.

REFERENCE

Wolak, Frank A. (2000) "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market," *International Economic Journal*, Summer 2000, 1-40.