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Transmission pricing in California's proposed electricity market

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The California electricity industry is scheduled to undergo a transition into a less-regulated, competitive market starting on January 1, 1998. This article provides an overview of the organization of this market and its general approach for managing transmission access and pricing. Much of this approach has been developed through a process of negotiation and compromise. The exact implementation of this approach may therefore end up producing an electricity marketplace that is quite different than the one envisioned by those privy to the negotiation process. © 1997 Elsevier Science Ltd. All rights reserved.

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Introduction

The electric systems of at least the 3 largest investor owned utilities (IOUs) in California are scheduled to be combined into a single, more competitive, market structure by January, 1998. This article discusses the proposed organization of the transmission and spot energy markets of this industry, and describes some of the major ambiguities remaining in the current proposals. The focus is this article is more one of description of the existing areas of agreement and disagreement than an analysis of all the areas of contention.

The structure that is now going forward is as much a product of negotiation as of any theoretical constructs of transmission pricing and rationing. It is also very much a work in progress. Much of what is described here comes from the filings of the 3 large IOUs to the Federal Energy Regulatory Commission (FERC) whose approval is necessary for any move towards pricing electricity and transmission at market-based rates. Two new institutions, an independent system operator (ISO) and a power exchange (PX), are in the process of being formed, and they are expected to adopt, pending FERC approval, the general framework that is laid out in these filings.

Background

In May 1994, the California Public Utilities Commission (CPUC, 1994) released a document, which came to be known as the 'Blue Book,' that called for the reorganization of California's electricity industry. The proposals for restructuring this industry included deregulation of the generation sector, some form of non-discriminatory access to transmission facilities, and incentive-based regulation for the transmission and distribution functions that were to remain regulated. An attachment to this document, written by then Commission President Fessler, foreshadowed subsequent disputes over the organizational form of the transmission sector by raising concerns over the implementation of transmission access. Fessler requested comments on the appropriateness of a pool-style market organization such as the one that had been adapted in the United Kingdom.

It turned out that San Diego Gas & Electric Co. and Southern California Edison felt, at least initially, that a pool-based approach was *very* appropriate for the California market (see Garber *et al.*, 1994, Budhraja and Woolf, 1994). These companies each proposed similar market structures organized around an independent 'PoolCo' that would serve as the market maker and also regulate transmission access according to the locational spot pricing principles of Schweppe *et al.* (1988). It was envisioned that the PoolCo market would penetrate further downstream than in the UK by allowing even retail customers 'virtual direct access' to suppliers through the pool (see Hogan, 1994).

However, a significant and vocal opposition to the PoolCo framework soon formed. These critics decried a centralized merchant and dispatch function as a move towards 'Soviet-style' central planning (see Varaiya,

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1997). Companies involved in the merchandising aspect of the industry, such as Enron and NYMEX were joined by representatives of large customers in protesting that forcing transactions through a pool would stifle the creativity of the marketplace and deny customers a true 'choice' of both supplier and product type. Some of the apparent shortcomings of the UK pool were held up as examples of how not to organize a marketplace. In many circles, it seemed that PoolCo was becoming a 4 letter word.

In fact, PoolCo eventually became a 3 letter word, MOU. In September of 1995, Southern California Edison, along with representatives of large energy consumers, submitted a Memorandum of Understanding (SCE *et al.*, 1995) to the CPUC. The MOU, as it came to be known, was essentially an 'assets for access' deal. The large customers agreed not to challenge SCE's position that it should be allowed to recover, through a non-bypassable competitive transition charge (CTC), the full value any of SCE's assets that became 'stranded' by the restructuring process, particularly the SONGS and Palo Verde nuclear generating units. In return, Edison agreed to back a market structure that would allow customers to directly negotiate power supply transactions *outside of the pool.* This hybrid market structure formed the basis of the CPUC's December 1995 decision on electricity restructuring (CPUC, 1995). The decision split the initially conceived PoolCo into at least 2 pieces, a Power Exchange (PX) that would perform the market making functions, and an Independent System Operator (ISO) that would be responsible for the operation of the grid and, if necessary, the rationing of access to congested paths.

Market organization

The market structure described here has emerged from the CPUC's December 1995 decision, the subsequent FERC filings by the IOUs that were called for in that decision (see WEPEX, 1996; ISO/PX, 1997), and the California legislatures Assembly Bill 1890. In November 1996, FERC (1996) issued a decision granting conditional approval of the general framework outlined in these proposals. Several important details currently remain unresolved.

California's 3 IOU's, Pacific Gas and Electric (PG&E), SDG&E, and SCE, are to be divided into affiliated generation companies (gencos), which will be unregulated, and distribution companies (distcos) that will remain regulated. Ownership of transmission assets will pass to the distribution companies, although control of these assets will be held by the ISO. The gencos will be required to sell, and distcos required to purchase, all of their power through the PX for at least 5 years. Any other power producers or customers may also participate in the PX on a voluntary basis. The PX is considered one of potentially many 'schedule coordinators' compiling load balanced power transactions that would then be submitted to the ISO. The ISO is supposed to ensure the feasibility of all the aggregated scheduled transactions and, if necessary, ration transmission access in a 'non-discriminatory' way between various schedule coordinators (including the PX). This process is described in more detail in Figure 1.

The PX is scheduled to begin operation on January 1, 1998. Initially, most customers will continue to be served by their local distcos, although, due to a recent decision

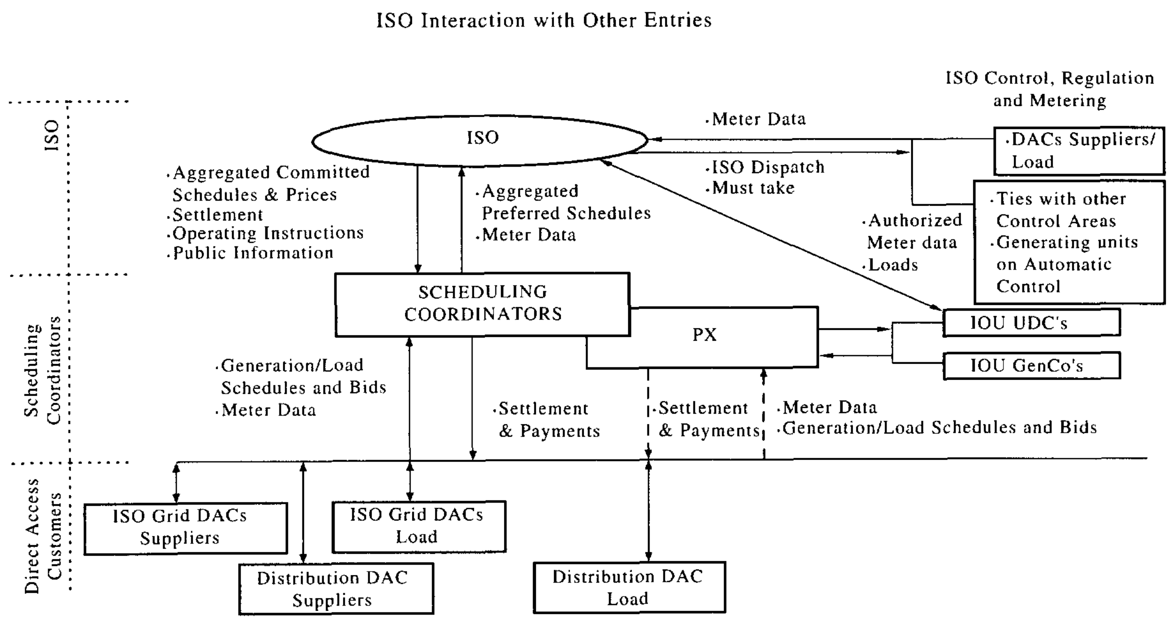

Figure 1. ISO interaction with other entities

(CPUC, 1997), all customers will have the option to bypass their distribution company and, with the right metering equipment, purchase power through a marketer or directly from the pool. Customers that select to bypass their distco will still be subject to the CTC, as well as to transmission charges. The focus of this article is on transmission pricing and therefore the bulk of our discussion is devoted to the protocols of the ISO. A brief description of the PX and its auction process is provided in the Appendix.

Transmission pricing

Transmission charges are to be divided into 3 categories: access fees, which are intended to recover the sunk costs of transmission investment, and congestion charges and loss compensation, both of which are supposed to reflect the operational costs of using the grid. The access fees relate directly to ownership issues and are discussed below, while the operational charges are best described in the context of congestion management and the dispatch of the generation market. This is done in a later section.

Access fees

The access fees are to be designed to "recover the full revenue requirement associated with the transmission facilities transferred to the ISO's operational control by each TO"[1] (WEPEX, 1996). The proposal is for a single, 'rolled-in' rate that would be uniform for similar customers in each TO's service area. The revenue requirement would essentially be the unbundled transmission component of the IOUs current revenue requirements, which the IOUs estimate in their application to be about \$16 per kWyr for SCE, \$17 per kWyr. for PG&E, and \$36 per kWyr for SDG&E. One major attraction of this approach was apparently the minimization of cost shifting both across utilities and between the customers of each existing utility.

There is a great deal of concern about free ridership on transmission facilities that will be combined under the ISO. The IOUs, in their application to FERC, outlined an approach for measuring the degree of 'self-sufficiency' of each TO's existing system. This test will measure whether the dependable generation in each TO's service area, along with any existing 'firm' transmission rights, are sufficient to meet the peak demand located in that TO's service area. Those TO's that are not self-sufficient under this test, would be deemed to be 'dependent' upon the transmission assets of other TO's and would therefore be responsible for paying some of the revenue requirements of that TO's transmission assets.

Other parties claim that the proposed system of access charges places an unfair burden upon firms that consume power supplied by local generation. The Southern California Gas Company (SCG), which distributes natural gas to many independent power producers in southern California[2], argued that a single access charge applied to all consumers in a service area amounts to a subsidy of out-of-state coal and nuclear generation. The costs of the facilities needed to import this out-of-state power would be paid in part by consumers of locally generated power that is not dependent upon those transmission facilities (SCG, 1996).

The self-sufficiency test does seem to be a curious throwback to reliability-based planning rules. A utility that could provide all its own power locally in a pinch will probably not do so in general, since it will be more economic to take advantage, resource-based, on seasonal regional cost differences. Thus the access charge allocates costs according to the planning-based reliability 'benefits', but not the economic benefits, of those facilities. Indeed, the California Municipal Utilities Association (CMUA) argues that such a method will give transmission dependent utilities an incentive to promote the addition of local generation, even if it increases congestion on the grid. The argument that customers should pay only for what they 'use' also ignores the potential economic benefits of transmission facilities for all customers in a given region. In an unregulated generation market, the price customers pay for local generation will not be based upon the cost of that generation, but upon the cost of alternative sources of supply. Borenstein *et al.* (1996) show that the benefits of increased transmission capacity in mitigating market power can be significant, even when that transmission capacity is not used.

In its recent decision, however, the FERC found that the access charge rate proposal "appears to be a reasonable method of recovering their individual transmission revenue requirements." They do acknowledge the uncertainty surrounding the concept of self-sufficiency, and state that their "preliminary review of the alternative rate design" that "appears to closely resemble the proposal of CMUA" indicates that this proposal "is also a reasonable method for recovering transmission costs."

Scheduling and congestion management

A key component of the MOU, and the subsequent market structure that emerged from it, is the separation of the market making and grid management functions that had been combined under the PoolCo proposal. As described above, the PX would become one of potentially many market makers while the ISO would have ultimate responsibility for resource scheduling and congestion management on the ISO controlled grid.

One of the controversial aspects of separating a pool's responsibilities into PX and ISO components is the extent to which the ISO, an entity that is not supposed to be involved in commercial decisions, can use economic criterion to ration transmission resources. Under the most extreme form of such a separation, the ISO would not use any price or cost information in making decisions about rationing transmission access. Proponents of the 'decentralized' approach to these markets often described an iterative process whereby coordinators, upon being informed that their proposed dispatches violated grid constraints, would perform trades with each other that could, in theory, lead to an optimal feasible dispatch.

In California, it was instead decided that, in conjunction with a limited iterative process, the ISO could also use *some* economic criteria for the rationing of transmission capacity. However, both the scope of economic information that the ISO can utilize and the range of actions the ISO can take in response to this information are relatively limited in comparison to a market with a fully integrated pool.

The limited economic information that the ISO will have access to consists of 'adjustment bids' submitted by the schedule coordinators for deviations from their specified 'preferred schedules'[3]. These bids are a series of price–quantity points that reflect what that SC is willing to pay (or receive) for differing levels of consumption (or supply) at a given point in the grid. These bids are intended to play the role that 'cost' and 'demand' curves do in a nodal pricing market. When the aggregate schedules submitted by all the SCs results in a congested interface, the ISO can produce a new, feasible schedule, by moving SCs away from their preferred schedules in a way that minimizes total congestion costs (as indicated by the adjustment bids). The transmission usage charge paid by all SCs that impact the congested path is this least-cost adjustment to the original schedules.

Two significant restrictions apply to the ISO's use of adjustment bids. First, redispatch by the ISO is indicated only when the market response fails to mitigate transmission congestion and such redispatch is constrained to the extent needed for alleviating congestion or for load balancing. Once these 2 objectives have been achieved, the ISO is prohibited from further intervention for the purpose of improving efficiency. Second, the redispatch must preserve the load balance for each individual schedule coordinator (i.e. any decrement at one bus needs to be matched by an equal increment at another bus). The important difference here from pool-based nodal spot markets is that it is the *transmission* price between locations, rather than *energy* prices at each location[4], that is equalized for every participant.

If the adjustment bids reflect the marginal energy costs at the corresponding buses, the above procedure equalizes the marginal congestion (displacement) cost across scheduling coordinators participating in the redispatch. In other words, the 'transmission' costs arising from congestion are equated across scheduling coordinators. Proponents of this approach argue that it results in efficient congestion relief (since it equalizes the marginal cost of congestion relief resources across system coordinators) while respecting the possible diversity of marginal energy prices across schedule coordinators which is a characteristic of many 'real-world' markets. It is further argued that any redispatch beyond congestion relief in order to exploit possible efficiency gains should be left to direct trading between the SCs at their discretion.

Critics of the above approach favor the relaxation of the balanced schedule constraint and argue that the ISO should be allowed to use the adjustment bids 'all the way' for efficiency improvement redispatch if the adjustment bids indicate potential gains from trade[5]. This latter approach would in effect create a role for the ISO as an arbitrageur among schedule coordinators.

The congestion management process

Scheduling and congestion management is done in 3 phases: day-ahead scheduling, hour-ahead scheduling and real-time scheduling. The ISO, when faced with an infeasible set of day-ahead schedules, provides a 'suggested' redispatch. Scheduling coordinators will have the option of adjusting their day-ahead schedules in response to this suggested redispatch. These changes may stem from agreements between SCs that are reached outside of the ISO or the PX.

There is some concern that the PX, which will operate under a rather rigid set of rules and protocols will not be able to take full advantage of the opportunities for 'self-management' of congestion that will be available to other schedule coordinators. If the operating rules of the PX give other coordinators a significant competitive advantage, this 'official' market may not survive far beyond its mandated 5 year transition period[6].

Day-ahead scheduling. At the beginning of each working day prior to the operating day, the ISO receives a preferred balanced schedule (including coverage of losses) from each of the scheduling coordinators, including the PX. The schedules specify the hourly injections and withdrawals in and out of the grid by location (bus)[7]. SCs may also submit adjustment bids (in the form of incremental/decremental prices for changes in generation or load at each bus) for use by the ISO in managing transmission congestion[8]. Prior to the submission of these schedules by the coordinators, the ISO provides an advisory forecast of expected total hourly load, congestion, and the ISO requirements for reserve and regulation ancillary services.

The ISO will combine the preferred schedules from all scheduling coordinators and use a power flow model to test the feasibility of the combined schedule in terms of coverage of losses, ancillary services requirements, reserve requirement, security criteria, and transmission capacity. If there is no congestion, the preferred schedules are accepted and the scheduling coordinators are notified by the ISO of their final transmission loss responsibilities.

If there is congestion, the ISO will use the adjustment bids provided by the scheduling coordinators to determine an *advisory redispatch* and provide to the scheduling coordinators the following information: (1) advisory redispatch schedule, (2) zonal prices for each congestion zone which will be used for determining interzonal transmission usage charges, (3) ancillary service prices, (4) updated transmission loss factors, and (5) power flow sensitivity to identify effective generation shifts for alleviating congestion. In developing the advisory redispatch schedule, the ISO will employ the adjustment bids, but will only make scheduling adjustments to the extent needed for relieving congestion (not to improve efficiency)[9].

Scheduling coordinators are allowed to respond to the tentative redispatch and zonal transmission prices by changing their preferred schedules in any form they wish but they *may not change any component of their price bids*. Based on the revised schedules submitted by the coordinators, the ISO will use the same procedure as in the advisory round to determine the *final day-ahead schedule* and zonal prices. These zonal prices will be used as market clearing prices by the PX for all PX suppliers and customers and the zonal price differences will be charged to all scheduling coordinators (including the PX) as a transmission usage charge applied to all interzonal power flows.

Hour-ahead scheduling. Scheduling coordinators may continue to revise their schedules following the completion of the ISO's day-ahead schedule coordination process and submit new schedules up until one hour prior to the beginning of the operating hour. The ISO will accept only changes that can be accommodated through adjustments of resources that have submitted bids for redispatch. Prior to the hour-ahead scheduling process the coordinators may also revise their adjustment price bids. These revised bids are used to price the differences between the final day-ahead schedule and hour-ahead schedule that are charged or credited to each of the coordinators. These prices are also used as an economic basis for redispatch in case that the hour-ahead schedules submitted by the coordinators result in congestion. When such congestion is detected, the ISO will again make scheduling adjustments only to the extent necessary to relieve congestion but this time the ISO's adjusted hour-ahead schedule is final, i.e. the coordinators are not allowed another chance to revise their schedule in order to relieve congestion (they may still deviate from their schedule but such deviation will be treated as imbalances and priced *ex post* based on the real-time market prices).

The revised price bids used in the hour-ahead market, along with the current prices for various ancillary services, will also be used by the ISO to preform real-time congestion management and balancing in a least-cost manner. These hour-ahead prices will also determine the hour-ahead zonal prices and resulting hour-ahead transmission usage charges (zonal price differences). The hour-ahead transmission usage charges are only applied to the *difference* between the interzonal flows in the day-ahead schedule and the actual real-time interzonal flow.

Real-time balancing. Following the finalization of the hour-ahead schedules, the ISO will dispatch its ancillary service generation (including generation arranged through the ancillary service market and ancillary service generation self-provided to the ISO by the coordinators) to balance the grid and respond to contingencies. The ISO may also utilize the final hour-ahead adjustment bids of the SCs in order to revise the dispatch in a least-cost (given these prices) manner. Based upon these resources, a price for imbalance energy will be computed every 5 minutes, or, if that is not computational feasible, every hour. Any imbalances between the hour-ahead final schedules of the coordinators and their real-time injections or withdrawals will be settled *ex post* by the ISO based on this marginal price of the imbalance energy.

Pricing of transmission usage

The pricing of transmission usage is meant to be based upon the locational (or nodal) pricing principles first articulated by Schweppe *et al.* (1988). In its pure form, however, locational prices should be defined at every bus on the network. In an effort to simplify this approach, buses were combined into pricing 'zones' with the thought that every bus in a zone would have the same locational price. However, while there is a reasonably complete and coherent theory behind nodal pricing at the bus level, zonal pricing has no such theoretical underpinnings. As a result, a series of heuristic rules were developed to test whether the prices at buses within a zone were similar enough to be treated as identical for transmission pricing purposes.

Definition of congestion zones

Transmission congestion zones play no role in the actual congestion management, which is based on a complete power flow analysis and redispatch according to the adjustment bids provided by the scheduling coordinators. The main role of the congestion zones is in determining the transmission usage charge and in locational differentiation of the PX market clearing prices. Zones are defined in terms of a test: if the annual congestion mitigation cost (through redispatch or load curtailments) within a region, exceeds 5% of the annual revenue requirement (or equivalently the transmission access charge) for the transmission lines into the region, that region is considered a distinct zone. Designation of transmission congestion zones is under the authority of the ISO. Initially, however, 2 zones have been identified in California, which meet the above criterion. One zone comprises the SCE, SDG&E and the southern part of PG&E territory, while the second zone comprises the remaining portions of the PG&E territory[10]. The capacity of Path 15, which connects PG&E's southern territory as well as the SCE and SDG&E territories to the north, is rated at about 3500 MW. According to historical data, annual congestion mitigation costs on path 15 is estimated at $2,830,000 (slightly below the 5% threshold).

Transmission usage charge

The transmission usage charge is essentially a congestion charge collected by the ISO from the scheduling coordinators. The transmission usage charge is defined as the difference in zonal prices and is applied to the flow along the congested inter-ties linking the congestion zones. SCs with schedules that relieve congestion on a congested interface receive a credit equivalent to the difference in zonal prices. The usage charge consists of 2 parts. The first part is based on the day-ahead zonal prices and is applied to flows based on the final day-ahead schedule. The second part is based on the hour-ahead zonal prices and it is applied to the deviation of the real flows relative to the final day-ahead schedule[11]. The revenues collected from the transmission usage charge will be credited against the revenue requirement of the transmission owners and will therefore reduce their access charges.

Summary

The proposed organization of California's electricity market is a hybrid system in which a pool-based spot market using locational prices is to operate in parallel with other markets that may include, but not be limited to, bilateral transactions between individual agents. The proposal also reflects several other compromises that represent significant departures from the underlying theories from which the original positions were developed. As such, the implementation of these compromises often depends upon heuristic rules whose effects are somewhat difficult to predict since they have yet to be tried anywhere. The pricing of transmission includes aspects of embedded cost recovery through access charges and marginal cost locational pricing through transmission 'usage' charges. The implementation of usage charges attempts to simplify nodal pricing by setting locational prices only over a small number of zones. Lastly, the management of congestion will allow for some decentralized adjustments between scheduling coordinators, but the ISO will make curtailment decisions based upon user specified cost information if those decentralized adjustments fail to converge to a feasible schedule in time.

[1]'TO' refers to transmission owner, which in most cases means the distribution spinoff of each of the three IOUs, although municipal utilities and other smaller transmission owning entities may enter the ISO framework.

[2]Pacific Enterprises, the parent company of SCG, has since reached an agreement to merge with the ENOVA corporation, parent of San Diego Gas and Electric.

[3]Schedule coordinators have the option of bidding only their preferred schedule. This ensures that they will not be curtailed (except under extreme conditions) but also limits their ability to revise their schedules in response to transmission charges.

[4]Transmission prices are implicitly equal under nodal pricing since they are equivalent to the difference between prices at various locations. However, these differences can be equalized without forcing uniformity of the energy prices at each node across scheduling coordinators.

[5]See Stoft (1996).

[6]Stoft (1997) observes that the alternative schedule coordinators, as potential competitors to the ISO, would stand to gain from the demise of the PX.

[7]Each coordinator will also provide the ISO with an advisory forecast of its expected hourly purchases of ancillary services from the ISO's ancillary service market. Coordinators are free to provide all of part of their ancillary service obligation (as determined by the ISO).

[8]The PX as well as any other scheduling coordinators can also provide marginal cost information for unscheduled resources (e.g. resources that submitted bids to the PX but did not win the auction) so that the ISO may use these resources to relieve congestion.

[9]Over and under generation due to the redispatch will be handled by the ISO by dispatching replacement reserves or pro-rata curtailment of non-price differentiated schedules.

[10]Originally, the city of San Francisco and a portion of Humboldt county have been also identified as congestion zones in according to the above criterion. Total transmission capacity into the San Francisco zone is rated at 700 MW, while transmission capacity into the Humboldt zone is rated at about 80 MW. According to historical data, annual congestion mitigation costs in San Francisco (extra fuel cost of using local generation) was estimated at $2,300,000 and the annual congestion mitigation cost in the Humboldt zone was estimated at $750,000. However, the marginal prices in the San Francisco and Humboldt zones are set by relatively expensive local units that operate most of the time as 'reliability must-run' generators. Hence, these areas have now been designated as 'inactive zones' whose zonal price will not differ from that of the northern California zone.

[11]If the deviation relieves scheduled congestion it produces a credit.

[12]When the total generation by constrained resources exceeds the PX total demand, the PX declares an over generation condition and a mitigation protocol is enacted by the ISO, which will direct other coordinators to reduce their generation as needed.

[13]Zonal prices may still vary, but the differences take the form of transmission charges.

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Appendix

The power exchange auction

The day-ahead schedule submitted by the PX to the ISO is based on an auction including bids from generators, demand side bids, and, potentially, bids from other scheduling coordinators. Some of the key features of the proposed PX auction are described below. Wilson (1997) provides a more detailed discussion of the PX auction protocols. The 3 major California utilities must (for the first 5 years) buy the power needed to serve their full service customers from the PX and bid their generation into the PX. Constrained resources such as regulatory must-take (e.g. QF), hydro spill and reliability must-run generation (per ISO estimates) are scheduled directly with the ISO. The PX is notified, however, of these constrained resources and must account for them in its own schedule.[12]

The proposed power exchange auction is a day-ahead auction conducted simultaneously for 24 hours (divided into one hour intervals) over a 2 hour period. The key features of the auction are (1) uniform *energy* price[13], (2) one dimensional bids (energy price only), (3) self-scheduling, and (4) multiround (only the last round binding).

The uniform price aspect of the auction (which is attributed to the CPUC ruling on this matter) implies that in each hour all the energy transacted by the PX is purchased and sold at one market clearing price regardless of location or bid price. If there are zonal price differences, users of the PX will pay these extra charges as part of a transmission fee added to the uniform energy charge. At this time it appears that PX prices will be finalized before the zonal charges are determined.

The auction is one dimensional in the sense that bids may only specify energy prices for each of the 24 hour intervals. Furthermore, the market clearing price for energy in each hour is based on the energy price bids for that hour. The auction does not enlist information on start up and no-load costs, or on operational constraints that would be needed for central unit commitment calculations. There is no 'uplift' added to the market clearing energy price nor any other transfer payment from buyers to sellers to compensate sellers for costs not covered by their energy revenues.

The auction relies on self-scheduling by the bidders, i.e. each bidder is expected to do its own unit commitment and account through its tender offers and energy price bids for intertemporal costs and constraints.

The auction is conducted in multiple rounds over a 2 hour period (until prices converge or up to about 8 rounds) with only the last round binding. The multiple rounds facilitate the self-scheduling aspect of the auction by allowing bidders to adjust their bid energy prices so as to cover intertemporal costs and meet operational constraints. In order to force early price discovery (i.e. preventing bidders from waiting on the side line until the last round) the auction rules include an activity rule which 'freezes' any tender that does not clear the market in 2 subsequent rounds (i.e. is priced twice in a row above the market clearing price for that hour.) However, a frozen tender can be 'unfrozen' in subsequent rounds if the market clearing price rises above its last bid price. Bidders cannot raise prices of a tender but are allowed to irrevocably withdraw a tender in any round except the first and the last.