Diagnosing Unilateral Market Power in Electricity Reserves Market

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Abstract

We use information released during the investigation of the California electricity crisis of 2000 and 2001 by the Federal Energy Regulatory Commission to diagnose allocative inefficiencies in the state's wholesale reserve markets. Material that has been largely neglected allows us to replicate market outcomes with a high degree of precision for the second and third quarters of 2000. Building on the work of Wolak (2000), we calculate a lower bound for the sellers' price-cost margins using the inverse elasticities of their residual demand curves. The downward bias in our estimates stems from the fact that we don't account for the hierarchical substitutability of the reserve types. The margins averaged at least 20 percent for the two highest quality types of reserves, regulation and spinning, generating millions of dollars in transfers to a handful of sellers. We attribute the deviations from marginal cost pricing to the markets' high concentration and a principal-agent relationship that emerged from their design.

JEL Classification Codes: L1, L9

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1 Introduction

Under the motto "Reliability through Markets," the reform of the California wholesale electricity sector was implemented in April of 1998 creating an intrinsically complicated market structure. An unbundled system in the language of Wilson (2002), the new setup was the result of a market design, where ideological rhetoric played a bigger role than serious analysis. (Joskow [2001]) Prior to late spring of 2000, the restructured California electricity markets delivered wholesale prices comparable to those in the Northeast part of the country, which underwent similar restructuring efforts (Wolak 2003c). Beginning in late May of 2000, California's markets entered almost a year-long period of severe turbulence highlighted by skyrocketing prices, the collapse of the California Power Exchange, the bankruptcy of the state's largest utility and the first rotating blackouts since World War II. California's electricity expenses were $15 billion between April 1998 and May 2000. They reached the staggering $38 billion between May 2000 and June 2001 to a large extent due to the exercise of market power in the state's energy markets (Hildebrandt [2001]; Sheffrin [2001]; Borenstein, Bushnell and Wolak [2002]; Joskow and Kahn [2002]; Wolak [2003]; Puller [2007]).

In this paper, we diagnose unilateral market power in the state's reserves market. To our knowledge, this is the first study that tries to shed light on the allocative inefficiencies of reserve markets in restructured electricity industries. One considerable barrier to investigating market power in reserve markets is the lack of publicly available data linking reserve bids with firms. We leverage the information released by the Federal Energy Regulatory Commission (FERC) following the events of 2000 and 2001 that matches bids with market participants. We are able to replicate market outcomes with a great degree of precision for the second and third quarters of 2000.

Our empirical strategy follows Wolak (2000) and identifies the *ability* of firms to exercise market power. In particular, we estimate the price elasticity of the ex post residual demand faced by each reserve supplier at the market clearing prices. In our setting, the inverse of this ex post residual demand elasticity provides a *lower bound* of the supplier's ability to price above marginal cost. The potential downward bias stems from our lack of data on the cross-price elasticities across the reserves' hierarchical markets. Given positive cross-price elasticities, the inverse of a product's own-price elasticity is a lower bound on the ability of a market participant to price above marginal cost.

We show that, on average, reserve suppliers were able to price the two highest quality types of reserves, regulation and spinning, at least 20 percent above their marginal costs. We attribute these markups, which generated millions of dollars in transfers to a handful of reserve sellers, to the markets' high concentration, as well as to the principal-agent relationship between the markets' buyers (principal) and their supervisory authority (agent).

The remainder of the paper is organized as follows. We first provide a description of the reserve market's operations, rules and participants. We then illustrate the model of bidding behavior that provides the theoretical background of our empirical analysis. Subsequently, we provide intuition for the direction of the bias that we introduce. Finally, we conclude after presenting our findings.

2 Overview of Market Operations

During the period we study, Scheduling Coordinators (SCs) represented generators and load serving entities, such as the utility distribution companies (UDCs). SCs aggregated forward commitments between demand and supply for electricity at a wholesale level and submitted these schedules to the state's independent system operator, the California ISO (CAISO). The energy schedules were arrangements for potential physical delivery of a given amount of megawatt-hours (MWh), on behalf of the generators, say to the UDCs, usually on an hourly basis. The CAISO provided transmission services to the SCs on an open and non-discriminatory basis. The SCs maintained an account with the CAISO for their assigned share of all the costs related to the CAISO controlled grid operations. Such charges included the grid operation and management charges, charges for the purchase of reserves, as well as charges related to the CAISO imbalance energy market. As long as the SCs met their financial obligations with the CAISO, they were able to arrange transmission services with the CAISO.

The SCs submitted their energy schedules to the CAISO twice: a day-ahead (DA) and an hour-ahead (HA) of the settlement period of the trading day they referred to. Energy schedules had to be balanced, i.e. demand had to equal supply. Each day of the week was a trading day. Each of the 24 hours of the trading day was a settlement period beginning with the interval 12:00 (midnight)-1:00. The SCs submitted their final DA energy schedules at 12:00 the day before the trading day for all of its settlement periods. The HA market was a deviations market and it was the last phase prior to real-time operations; it represented any changes from the DA commitments due to updated forecasts of generation, demand, any inter-SC trades etc.. The CAISO received HA schedules one hour before the beginning of the relevant settlement period of the trading day. In the absence of any changes, the HA energy schedules were simply the DA energy schedules.

The CAISO accommodated real-time deviations from the HA energy schedules using *reserves* of *unloaded power*, or *ancillary services* in the industry jargon, and the so-called supplemental energy offers in its imbalance market.[1] The imbalance market operated for each settlement period of the trading day. The ancillary services were vertically differentiated by their "quality"—the speed at which they can provide their power once called upon; higher quality products could substitute for lower quality products, but not vice versa.[2]

The highest quality service, regulation, allowed the CAISO to fine-tune generation up and down to meet random minute-to-minute demand and supply fluctuations through automatic control. The regulation offer of a generating unit was less than or equal to its ramp rate, expressed in MWs per minute, times a period that varied between 10 and 30 minutes. The CAISO announced to the SCs the exact period with a 24-hour advance notice. The remaining ancillary services required the manual intervention of their operator upon a dispatch instruction by the CAISO to convert their megawatts (MW) of capacity reserved into energy (MWh).

[1]SCs also represented the supplemental energy resources, i.e. generating units and curtailable loads (e.g., commercial air-conditioning and municipal water pumping systems).

[2]For the theoretical literature of vertical product differentiation, where consumers agree on the quality ranking of the products, but differ in their choices due to different marginal utilities of income, see Mussa and Rosen (1978), Jaskold-Gabszewicz and Thisse (1979), as well as Shaked and Sutton (1982).

Spinning reserves followed regulation in the hierarchy. They were able to respond to a CAISO notice within 10 minutes. The amount of spinning that a SC's on-line unit offered was less than or equal to its ramp rate times 10 minutes. Off-line units and curtailable load provided the next product, non-spinning reserves. Off-line generating units' non-spinning offers were less than or equal to their ramp rates times the difference between 10 minutes and the time they needed to synchronize with the system. The non-spinning offers of curtailable load were less than or equal to the time to interruption times the difference between 10 minutes and the time to interruption. The final product, replacement, was similar to non-spinning, but required a 60-minute "lag" in its response to a CAISO notice.

A long list of minimum operating reliability criteria and performance standards dictated the amount of regulation, operating and replacement reserves that the CAISO needed to maintain for each settlement period of the trading day. In addition to these guidelines, the CAISO also took into account close-to-real-time system conditions (e.g., congestion, fuel mix of generation units etc.), as well as historical patterns of deviations from final energy schedules, to calculate its reserve requirements. For example, the CAISO's operating reserve requirements were calculated as 5 percent of the SCs' demand scheduled to be served by hydroelectricity plus 7 percent of the SCs' demand scheduled to be served from other resources.

The CAISO assigned a fraction of its total reserve requirements to each SC based on the SC's share to the total scheduled demand served by generation within the CAISO control area. In many cases, the SCs partially or completely "self-provided" their reserve obligation to the CAISO with the mix of generation and curtailable load they represented, after accounting for the energy commitments of these resources. The CAISO bought any differences between its total reserve requirements and the sum of SCs' self-provisions in the DA and/or HA markets from the SCs that were selling reserves. The first class of reserve sellers were SCs that had submitted forward energy schedules and had positive net reserve positions, i.e. had already covered their obligation to the CAISO. The second class of reserve sellers were SCs that had not submitted forward energy schedules to the CAISO and had no reserve obligation to begin with. This latter class of SCs represented generating units and interruptible loads only for the purpose of their participation in the reserve markets.

The CAISO had full discretion over the allocation of its reserve purchases in the DA and HA markets; it allocated its total reserve expenses among the SCs with reserve obligations adjusting for any self-provisions based on their metered energy demand. Because the CAISO did not bear the cost of the ancillary services, it had little incentive to attempt to arbitrage any price differences that may have existed between the DA and HA markets. Historically the CAISO made 80 percent of its purchases DA.

2.1 Ancillary Service Auctions

By 18:00, two days ahead of the trading day, the CAISO published an hourly forecast of its grid conditions, a forecast of the system demand and an estimate of its requirements for reserves. Following multiple rounds of information exchange with the SCs, the CAISO received the SCs' final DA self-provided reserve schedules and reserve bids by 12:00 (noon) on the day before the trading day. The SCs submitted their HA self-provided reserve schedules along with their reserve bids, only for the relevant settlement period of the trading day one hour before its beginning. Similarly to the energy markets, the HA reserve market was a deviations market reflecting changes in the SCs' DA positions due to energy schedule adjustments, plant outages etc.

The SCs submitted a separate bid or a self-provision schedule for each unit or interruptible load they represented in a simultaneous sealed-bid auction. Bids for regulation were in the form of a single quantity (MW) and price ($/MW) pair. Bids for the operating and replacements reserves included an energy in addition to their capacity component. The energy component was a non-decreasing function (up to 10 steps) that mapped MWh to $/MWh and was used to determine their compensation for energy released in the imbalance market.

From the CAISO's perspective, purchasing DA and HA reserves was equivalent to obtaining the right, but not the obligation, for calling energy up to the amount of reserve bought in the imbalance market. Hence, the CAISO signed a European-style call option, where the underlier was imbalance energy, for each MW of reserve that it procured DA and HA. The resulting reserve market clearing price was the option's price. The clearing of the imbalance energy market determined the option's strike price (Bohn, Klevorick and Stalon [1998]).

The CAISO software cleared the DA and HA reserve markets using only the (MW, $/MW) pairs of the SCs' reserve bids. For the period we study, the CAISO procured ancillary services using a "rational buyer" algorithm. The objective of the rational buyer algorithm was to minimize the total reserve procurement cost capitalizing on the hierarchical substitutability of the reserves (Liu et. al. [2000]). Setting aside physical constraints (e.g., generating capacities, ramp rates etc.), the algorithm's minimization problem for each settlement period in the DA and HA markets was:

$$\begin{aligned} \underset{\mathbf{p}}{min}\ \mathbf{p}^{\top} q\left(\mathbf{p}\right) \quad s.t. \quad & \textstyle\sum_{l \in J} \mathbf{1}\left(l \leq j\right) q_l \geq \sum_{l \in J} \mathbf{1}\left(l \leq j\right) Proc_l,\ \ j = 1,2,3 \\ & \textstyle\sum_{l \in J} \mathbf{1}\left(l \leq j\right) q_l = \sum_{l \in J} \mathbf{1}\left(l \leq j\right) Proc_l,\ \ j = 4, \end{aligned} \tag{1}$$

where $\mathbf{p}$ and $q\left(\mathbf{p}\right)$ are column vectors of reserve prices and capacity offers, respectively. We use $Proc_j$ to denote the CAISO procurement for reserve type $j \in J = \{1,2,3,4\}$, where 1 is regulation up, 2 is spinning, 3 is non-spinning and 4 is replacement. The value of the indicator function $\mathbf{1}\left(\cdot\right)$ is one if its argument is true. The prices in $\mathbf{p}^* \in argmin\ \mathbf{p}^{\top} q\left(\mathbf{p}\right)$ that satisfied the above equality and inequality constraints were paid to all the infra-marginal bids (uniform price auction).[3]

Whenever the DA and HA market energy schedules were accommodated without the need for inter-zonal congestion management and re-scheduling, the CAISO procured reserves through a system-wide auction generating system-wide market clearing prices for each product. In the presence of congestion, requirements were established on a zonal basis and the procurement was carried out separately in each zone, resulting in zonal market clearing prices. The CAISO tariff defined two major congestion zones, on the two sides of path 15,

[3] Reserve markets may be viewed as special types of multi-dimensional auctions where generators compete by submitting two-part bids consisting of capacity and energy bids as Wilson (2002) mentions: *"...The design of reserve markets has had a tortuous history..."* and he continues: *"...The theory of multi-dimensional auctions is complicated, and judging from occasional disasters, so is practical implementation..."*. **See also the discussion in Chao and Wilson (2002) and Kamat and Oren (2002).**

a major transmission interface in the state. The first congestion zone was north of path 15 (NP15) and the second congestion zone was south of path 15 (SP15). Other congestion zones were areas within which congestion was infrequent, small and difficult to predict.

3 Diagnosing Unilateral Market Power: Theoretical Background

A number of studies estimate market power in wholesale energy markets using data on engineering costs.[4] A similar analysis for ancillary service markets is complicated by the capacity nature of the markets. The true economic costs of bidding in the DA and HA reserves markets may involve a fixed standby cost and/or an opportunity cost of not providing energy for the reserve resource under consideration. Because the opportunity costs of providing ancillary services may differ significantly from the engineering costs, analyzing market power in ancillary service markets does not afford itself well to using engineering data.

Our underlying assumption is that the outside option for a reserve resource is to participate in the energy market. More specifically, spinning and regulation units are required to be on-line and running at their minimum level. This requirement implies a fixed cost (being on-line) and an efficiency penalty. For example, steam units achieve their regulation and spinning ramp rates by having their valves in reserve-throttle, i.e. half-open instead of wide-open, which is detrimental to their efficiency (Perekhodtsev [2004]). Combustion turbine peaking units that provide non-spinning and replacement reserve, on the other hand, can be off-line. Hence, they do not face any fixed costs, as it is also the case with curtailable loads.

The opportunity cost of generating units providing reserves depends on whether their total (variable plus fixed) costs are below or above the price of the energy market that they may participate. We call variable the component of total cost associated with energy released from the reserve. For units with total costs below (above) the energy price, the opportunity

[4] See, for example, Wolfram (1998), Borenstein, Bushnell and Wolak (2002) and Joskow and Kahn (2002).

cost is their foregone profit of providing energy (zero). For example, for an energy price of \$30/MWh, a spinning unit with total cost of \$20/MWh has opportunity cost of \$10/MWh. Off-line non-spinning and replacement units with variable operating costs below (above) the energy price face only an opportunity cost (no costs). For hydro units with storage capacity and restraints on water releases, the opportunity cost of providing reserves also depends on energy and reserve prices in settlement periods other than the one under consideration. The intuition we just developed is further complicated once we incorporate the hierarchical substitutability of the reserves, as well as the interaction between the DA and HA reserve markets.

We adopt the model of expected profit-maximizing bidding behavior in wholesale electricity markets to diagnose the extent of unilateral market power in the DA reserves markets for the second and third quarters of 2000 (Wolak [2000]). We provide a proxy for price-cost markups using the inverse elasticities of the SCs' residual demand curves for each type of ancillary service. Our results serve as a lower bound on the ability of any one generator to exercise market power because of the likelihood of positive cross-price elasticities across these substitutes.

We focus on the DA markets because they attracted 80 percent of the forward reserve transactions for the period that we are interested in and we ignore its interactions with the imbalance energy market.[5] The price of reserve j in settlement period t is p_{jt}, with $j \in J = \{1, 2, 3, 4\}$, as above. A settlement period (hour) is an observation and is fully identified by $t = 1, \ldots, T$, where T is the available sample for our analysis (e.g., a year of available observations would imply $T = 365 \times 24 = 8760$). The set of SCs is N and $N_{-i} = N/\{i\}$. Ignoring the reserves' substitutability, the amount of reserve j bid by all other SCs beyond SC is $SO_{ijt}(p_{jt})$. The residual demand faced by the SC i is $DR_{ijt}(p_{jt}) = Q_{jt} - SO_{ijt}(p_{jt})$ (see Figure 1). If the total cost of providing $DR_{ijt}(p_{jt})$ for SC i is $C_{ijt}(DR_{ijt}(p_{jt}))$, its profit

[5] The total payment that a SC receives for 1 MW of reserve that makes available to the CAISO is equal to the capacity payment plus the product of the market clearing prive and the expected energy released from its reserve during the imbalance market operations (the so-called "double dipping"). The SC may give up energy for capacity payments for the same amount of total payments (and vice versa), say, if there is a small possibility for its reserves to be called in the imbalance market.

function for reserve of type j in settlement period t is:

$$\pi_{ijt}(p_{jt}) = p_{jt} \times DR_{ijt}(p_{jt}) - C_{ijt}(DR_{ijt}(p_{jt})) . \tag{2}$$

As opposed to the usual (e.g., Bertrand or Cournot) oligopoly models used in the empirical IO literature, the residual demand function of the player (SC i) under consideration, $DR_{ijt}(p_{jt})$, is *ex-post directly observable*. We only need the bids submitted by the remainder of the players and the aggregate market demand, which are both publicly available. The advantage of this strategy is that neither functional form assumptions, nor instrumental variable techniques for the purpose of parameter estimation in the residual demand function, are required.

Following the intuition in Wolak ([2000], [2003a] and [2003b]), there are stochastic residual demand shocks in each settlement period and the SC i knows the distribution of these shocks. The uncertainty could be due to a stochastic component in $SO_{ijt}(p_{jt})$, or an additive error in Q_{jt}. Although we assume that the SC i knows the distribution of its residual demand shocks, we do not need to be specific about the source of the uncertainty because we do not solve for an equilibrium. Had the SC i been able to observe the uncertainty, it would maximize its profit conditional on its value ignoring its source.

We denote the shock to SC's demand function as $\varepsilon_{j\tau}$ and we write the residual demand that incorporates this shock as $DR_{ij\tau}(p_{j\tau}, \varepsilon_{j\tau})$, $\tau = 1, \ldots 24$. We also define $\theta = vec(B)$, where $B = (b_{ijk\tau})$ is $(24 \times K) \times 2$ matrix of the price (p_{ijkt}) and quantity (q_{ijkt}) elements in the capacity component of the daily bids submitted by the SC i for the $k = 1, \ldots, K$ resources it represents. The dimension of θ is $(24 \times K \times 2) \times 1$. If we stack the cumulative sum of $q_{ijk\tau}$ in ascending order of $p_{ijk\tau}$, the resulting curve $S_{ij\tau}(p_{j\tau}, \theta)$ is non-decreasing in $p_{j\tau}$. The solution to the equation $DR_{ij\tau}(p_{j\tau}, \varepsilon_{j\tau}) = S_{ij\tau}(p_{j\tau}, \varepsilon_{j\tau})$ is $p_{j\tau}(\varepsilon_{j\tau}, \theta)$ and the joint density of $\boldsymbol{\varepsilon}_j = vec\left((\varepsilon_{j\tau})_{\tau=1}^{24}\right)$ is $g(\boldsymbol{\varepsilon}_j)$ yielding the following expected profit to SC i for its daily bid vector θ:

$$E\left(\pi\left(\theta\right)\right) = \int \ldots \int \sum_{\tau=1}^{24} \left[p_{j\tau}\left(\varepsilon_{j\tau},\theta\right) \times DR_{ijt}\left(p_{j\tau}\left(\varepsilon_{j\tau},\theta\right)\right)\right] g\left(\left(\boldsymbol{\varepsilon}_j\right)\right) d\varepsilon_{j1}\cdots d\varepsilon_{j24}$$
$$- \int \ldots \int \sum_{\tau=1}^{24} \left[C_{ij\tau}\left(DR_{ijt}\left(p_{j\tau}\left(\varepsilon_{j\tau},\theta\right)\right)\right)\right] g\left(\left(\boldsymbol{\varepsilon}_j\right)\right) d\varepsilon_{j1}\cdots d\varepsilon_{j24}. \quad (3)$$

The *best-response bidding strategy* for SC i is the vector θ^* that maximizes $E\left(\pi\left(\theta\right)\right)$ subject to linear inequality restrictions of the form $H \geq R\theta \geq L$, that reflect market rules, as well as units' operation constraints such as ramp rates, generating capacity etc., discussed in the previous section. Setting aside the high dimension of θ, the non-linear optimization problem to calculate such strategy involves integration in a 24-dimenisonal space with the integrand being the sum of discontinuous functions and is a rather non-trivial exercise. However, if we write the profit equation in (2) with the residual demand incorporating the shock for the settlement period under consideration, we get the *ex post realized* profits for the SC i:

$$\pi_{ijt}\left(p_{jt},\varepsilon_{jt}\right) = p_{jt} \times DR_{ijt}\left(p_{jt},\varepsilon_{jt}\right) - C_{ijt}\left(DR_{ijt}\left(p_{jt},\varepsilon_{jt}\right)\right). \quad (4)$$

In the language of Wolak (2000), $p^*_{jt}\left(\varepsilon_{jt}\right) = argmax_{p_{jt}}\pi_{ijt}\left(p_{jt},\varepsilon_{jt}\right)$ is the *best-response price* for the residual demand curve $DR_{ijt}\left(p_{jt},\varepsilon_{jt}\right)$ when the shock is ε_{jt}. The price $p^*_{jt}\left(\varepsilon_{jt}\right)$ and the quantity $DR_{ijt}\left(p^*_{jt}\left(\varepsilon_{jt}\right),\varepsilon_{jt}\right)$ yield the highest profit that the SC i can attain given the bidding behavior of its competitors and its residual demand shock realization. The SC i may then construct its *expected profit maximizing bidding curve* by tracing out the *ex post* profit-maximizing price and quantity pairs for its set of possible residual demand realizations (as illustrated in Figure 2). Furthermore, by imposing restrictions on the demand and the bid functions, as well as the way that the shocks ε enter these functions, tracing $\left(p^*\left(\varepsilon\right), DR\left(p^*\left(\varepsilon\right),\varepsilon\right)\right)$ yields a continuous strictly increasing supply function, as in Klemperer and Meyer (1989).[6] Regardless of the residual demand realization, the first-order

[6] **Hortaçsu and Puller (2007) assume additive errors in the supply and aggregate demand functions which produces residual demand curves that are parallel translations of each other in their study of the imbalance market in Texas. The supply function equilibrium (SFE) of Klemperer and Meyer (1989) has been extensively used to analyze bidding behavior in**

conditions that produce the best-response prices, once evaluated at the observed market clearing price p_{jt}^{e}, lead to the following equation:

$$\frac{p_{jt}^{e}-mc_{ijt}\left(DR_{ijt}\left(p_{jt}^{e},\varepsilon_{jt}\right)\right)}{p_{jt}^{e}}=\frac{-DR_{ijt}\left(p_{jt}^{e},\varepsilon_{jt}\right)}{p_{jt}^{e}\times DR_{ijt}^{\prime}\left(p_{jt}^{e},\varepsilon_{jt}\right)}=\frac{1}{\left|\eta_{ijt}\right|} \tag{5}$$

we compute $DR_{ijt}\left(p_{jt}^{e},\varepsilon_{jt}\right)$ directly using the actual CAISO procurement and the bids submitted by all other SCs beyond SC i. The market clearing price p_{jt}^{e} is also directly observed. It is then expected-profit-maximizing for the SC i to submit a bid curve such that its intersections with any possible residual demand realizations occur at prices where (5) holds for that particular demand realization and the resulting market clearing price p_{jt}^{e}.

Excluding the reserves' hierarchical substitutability in the best-response pricing calculations biases our price-cost markup estimates downwards. To show the direction of the bias, first, we maintain only reserve type subscripts, we drop ε and we write $DR_{j}\left(\mathbf{p}\right)=Q_{j}\left(\mathbf{p}\right)-SO_{j}\left(\mathbf{p}\right)$. Profit maximization then implies:

$$\frac{\left(p_{j}-MC_{j}\right)}{p_{j}}=\frac{1}{\left|\eta_{j}\right|}\left[1+\sum_{l\in J/\{j\}}^{4}\left(\frac{\left(p_{l}-MC_{l}\right)}{DR_{j}\left(\mathbf{p}\right)}\times\frac{\partial DR_{l}\left(\mathbf{p}\right)}{\partial p_{j}}\right)\right],\ j\in J, \tag{6}$$

which we call the *adjusted* inverse elasticity rule. The following also holds:

$$\frac{\partial DR_{l}\left(\mathbf{p}\right)}{\partial p_{j}}=\frac{\partial Q_{l}\left(\mathbf{p}\right)}{\partial p_{j}}-\frac{\partial SO_{l}\left(\mathbf{p}\right)}{\partial p_{j}},\ l,\ j\ \in J\text{ with }l\neq j. \tag{7}$$

Although $\partial SO_{l}\left(\mathbf{p}\right)/\partial p_{j}\leq 0$ for all l and j with $l\neq j$, the reserves' hierarchical substitutability implies $\partial Q_{l}\left(\mathbf{p}\right)/\partial p_{j}\geq 0$ for $l,\ j\in J$ with $l<j$ and, hence, $1/\left|\eta_{j}\right|\leq\left(p_{j}-mc_{j}\right)/p_{j}$. The intuition behind the direction of the bias is as follows. Consider first the effect of an increase in the spinning price ($j=2$) on the regulation market ($l=1$). The regulation sup-

wholesale electricity markets. For early work using the SFE, see Green and Newberry (1992), Bolle (1992), Green (1996, 1999), Rudkevich (1999), Baldick and Hogan (2000). More recent work on the SFE includes Baldick, Grant and Kahn (2004), Holmberg (2007), Sioshansi and Oren (2007), Willems et al. (2007). The model of Kühn and Machado (2004) is similar to that of Hortaçsu and Puller because they both characterize Bayesian Nash Equilibria in terms of ex-post optimal supply curves based on an additive private information component.

ply decreases, $\partial SO_1(\mathbf{p})/\partial p_2 \leq 0$, and the regulation demand increases, $\partial Q_1(\mathbf{p})/\partial p_2 \geq 0$. Consider now the effect of an increase in the regulation price ($j=1$) on the spinning market ($l=2$). Although the spinning supply decreases, $\partial SO_2(\mathbf{p})/\partial p_1 \leq 0$, the spinning demand remains unchanged, $\partial Q_2(\mathbf{p})/\partial p_1 = 0$, because spinning does not qualify as a regulation substitute.

Estimating the cross-price derivatives in (6) would require some model of strategic interaction among the SCs and at least marginal cost estimates. Another option would be to make some functional form assumption with respect to the SCs' residual demand curves and estimate directly the cross derivatives (e.g., Bresnahan [1987], Greenstein [1996], or Berry and Pakes [2005]). This approach would be in a different spirit of the functional-form free one taken here.[7] In light of this, we focus only on the inverse of the own-price elasticity and interpret our results as lower bounds on market power.

A final step required for estimating market power is the need to approximate the slope of the residual demand curve. Because the residual demand curve for a reserve supplier is a step function, locally, the elasticity η_{ijt} is either zero or infinite. A simple approximation for the first derivative $DR'_{ijt}\left(p^e_{jt},\varepsilon_{jt}\right)$ is the *forward* difference approximation $\left(DR_{ijt}\left(p^e_{jt}+\delta,\varepsilon_{jt}\right) - DR_{ijt}\left(p^e_{jt},\varepsilon_{jt}\right)\right)/\delta$, for appropriately defined step size δ.[8] Wolak (2003a) suggests smoothing the corners in $SO_{ijt}(p,\varepsilon_{jt})$ using the following expression for $DR'_{ijt}(p,\varepsilon_{jt})$:

$$DR_{ijt}(p,\varepsilon_{jt}) = Q_{jt} - SO_{ijt}(p,\varepsilon_{jt}) = Q_{jt} - \sum_{n=1}^{N_{-i}}\sum_{k=1}^{K_n} q_{nkjt}\times\Phi\left(\frac{p-p_{nkjt}}{\delta}\right), \tag{8}$$

[7] It is also true that we do not impose any restrictions implied by the market rules on the bidding behavior of the SCs, which are somehow able to achieve $p^*_{jt}(\varepsilon_{jt})$ (see Wolak [2003a] for an excellent discussion on the issue). The adjusted inverse elasticity rule above may not hold on an hourly basis, but the deviations should not be economically significant. Hence, we focus on the differences in our markup proxies across the second and third quarters of 2000.

[8] The error in the *forward* difference approximation $\frac{f(x+\delta)-f(x)}{\delta}$ for step size δ of a function $f(x)$ is $O(\delta)$, for $|\delta| < 1$. The same approximation error emerges from the the *backward* difference approximation $\frac{f(x)-f(x-\delta)}{\delta}$. The *central* difference approximation, $\frac{f(x+\delta)-f(x-\delta)}{2\delta}$, is an improved version, yielding an approximation error of $O\left(\delta^2\right)$. Further improvements of the *forward*, *backward* and the *central* difference approximation methods are achieved using *Rischardson's extrapolation* (see Yang, et. al. [2005], among many)

$$DR'_{ijt}(p, \varepsilon_{jt}) = -\frac{1}{\delta} \sum_{n=1}^{N_{-i}} \sum_{k=1}^{K_n} q_{nkjt} \times \phi\left(\frac{p - p_{nkjt}}{\delta}\right), \tag{9}$$

where K_n is the number of resources represented by the nth SC in N_{-i}. Additionally, $\Phi(\cdot)$ is the standard normal cumulative function and δ is the bandwidth that controls the degree of smoothing.[9] See also Wolak (2003b) for the arc elasticity formula.

4 Empirical Analysis

4.1 Data

We restrict our attention to hours of DA system-wide procurements between April and September 2000 for regulation up, spinning, non-spinning and replacement. After imposing such a restriction, we use about 85 percent of the total available settlement periods within this span of 6 months; this yields 3683 hours (settlement periods). There are 1668 hours in the period between April 1st and June 30th (Q2, henceforth) and 2015 hours in the period between July 1st and September 30th (Q3, henceforth).

The CAISO Open Access Same Time Information System (OASIS) archive reports the reserve market-procured and self-provided quantities, as well as prices, for each settlement period. The CAISO requirement for each settlement period is the sum of the self-provided and market procured quantities. When we refer to the CAISO real-time and the California Power Exchange (CALPX) DA energy price, as well as to their summary statistics, we use the maximum of the NP15 and SP15 prices. We approximate the real-time energy requirements as the difference between the actual load and the HA CAISO forecast for the settlement period using data from the CAISO OASIS archive. The CAISO real-time energy prices are also from the CAISO OASIS archive. The CALPX DA quantities and prices are posted in the University of California Energy Institute (UCEI) website. Load forecasts refer to CAISO estimates, and load schedules are submitted by the SCs. The CALPX was not only

[9] Hortaçsu and Puller (2007) also follow such a smoothing approach.

the primary DA energy market between the spring of 1998 and before its collapse, late 2000, but also a SC. As a result, the CALPX DA market clearing quantities represent a fraction of the total load schedules.[10]

The information released during the FERC investigation of the California electricity crisis in 2000 and 2001 allows us to replicate the reserve market outcomes very precisely for the settlement periods we consider.[11] The portion of the information referring to the reserve markets data incorporates the Rational Buyer market clearing mechanism, which would be almost impossible to replicate with only the reserve markets data released by the CAISO. We replicate the prices (as posted in the OASIS archive) exactly for all the four types of reserves for 98 percent of the total (3683) settlement periods. We do so by stacking the capacity bids in ascending order of their price component and crossing them with the CAISO procurement. For the remainder of the settlement periods, which we also include in our sample, the absolute percentage deviation between the posted prices and the ones that we derive is less than 5 percent.[12] Therefore, we are confident that the residual demand curves used in our market power analysis reflect the actual market conditions with a sufficient degree of accuracy.

4.2 Preliminaries

Figures 3 and 5 provide time-series plots of the CAISO DA reserve procurements, as well as DA load schedules and their deviations from the DA system-wide forecasts. The under-scheduling (schedule less than forecast) averages 13 percent in Q2 and 15 percent in Q3 when evaluated at the mean DA schedule. The mean share of the CALPX to the total DA load

[10] Recall from our earlier discussion that the SCs submitted balanced energy schedules to the CAISO. The CALPX was a centralized market and its DA market clearing quantity was its balanced energy schedule for the hour. Being a centralized energy market, the CALPX made publicly available the transactions between its loads and generators in the form of market clearing prices and quantities. The remainder of the SCs that submitted energy schedules were small-scale clearinghouses with no publicly available data for the transactions between their loads and generators.

[11] Available at http://ferc.aspensys.com/FercData/Miscellaneous%20cd's/CAISO-881/. See also Barmack (2003).

[12] Assume that $p_1 > 0$ and $p_2 > 0$ are the posted market clearing price and the one that we calculate, respectively. We define the absolute percentage deviation as $|p_1 - p_2| / |min(p_1, p_2)|$

schedules is quite similar in both quarters: between 85 and 90 percent. Our proxy of real-time energy procurements represents on average 5 percent of the CAISO DA load forecasts in both quarters.

We truncate 42 hours of replacement at 3,000MW to show that reserve procurements follow under-scheduling very closely. A regression of the reserve procurements on a fifth-order polynomial of the load deviations and hourly, weekday/weekend, as well as monthly dummies, explained at least 95 percent of their total variation for regulation-up, spinning and non-spinning and 75 percent of the total variation in replacement.

The CAISO views substantial under-scheduling (e.g., incidents in mid-June) as threatening to the reliability of its controlled grid and, as a result, it boosts its reserve requirements. If the under-scheduling coincides with high load levels, the reserve requirements are almost equal to reserve procurements because the vast proportion of the system's generating capacity is devoted to energy. Reserve and energy procurements exhibit a positive statistically significant correlation in both quarters. With the exception of replacement, the average share of reserve procurement to requirement is between 80 and 90 percent in both quarters. The replacement requirements were covered entirely by self-provision for at least 65 percent of the settlement periods (Q2 and Q3).

With the exception of regulation up, the mean MW procurements (Table 1) are larger in Q3 than in Q2 for all reserves.[13] The same holds for both CALPX and real-time energy procurements, as well as for load schedules and deviations. While Q2 is more volatile than Q3 for the operating reserve and real-time energy procurements, the opposite holds for replacement. The difference in volatility between Q2 and Q3 is statistically indistinguishable from zero for regulation up and CALPX scheduled load. Procurements in excess of 1,200MW for regulation up and 1,500MW for operating and replacement reserves explain most of their kurtosis and stretch the right tail of their distributions in both quarters.

Figures 4 and 6 provide time-series plots for the DA reserve prices, as well as for the

[13] For all mean and standard deviation comparisons that we make throughout this section we performed one-sided t-tests and F-tests at 0.05 significance level, respectively.

CALPX DA and the CAISO real-time prices. The reserve (real-time energy) markets were subject to a price cap of \$750/MW(h), which was lowered at \$500/MW(h) on July 1, and subsequently to \$250/MW(h) on August 7. The CALPX DA energy market was subject to a price cap of \$2,500/MWh. Similarly to the quantities, the reserve and energy prices exhibit a positive statistically significant correlation in both Q2 and Q3. A plausible explanation behind the negative prices in Tables 2 and 1 is the following. A seller that is bidding a negative price tries to secure an infra-marginal spot in the supply curve free-riding on a high positive bid to clear the market. However, if many sellers employ this strategy and the procurement is lower than expected, such strategy backfires. As a result, the sellers end up paying for the reserves or the energy they provide. For example, on July 11, the replacement market procurement and price were 358.5MW and \$0.92/MW during hour 19, but they were 75MW and -\$99/MW during hour 20.

In many incidents of substantial under-scheduling, the CAISO procured amounts of reserves well in excess of their average levels creating many of the spikes in Figure 4. The implications of these procurements are more pronounced under conditions that stretched the system. For example, during hour 12 on June 14 and hour 11 on June 15, the CAISO load forecasts were 43,720MW and 39,200MW (the 95th percentile of forecasts is 39,470MW). The size of under-scheduling was in the neighborhood of 25 percent in both instances. The CAISO bought 6,073 MW and 6,167MW of replacement, respectively, with the replacement prices hitting \$749.45/MW and \$749.99/MW, when the price cap was \$750/MW.

The average reserve prices range between \$25/MW (non-spinning) and \$65/MW (regulation up) in Q2 and between \$12/MW (replacement) and \$96/MW (regulation up). The mean reserve prices are below the mean CALPX DA (Q2: \$74/MWh, Q3: \$122/MWh) and CAISO real-time (Q2: \$81.9/MWh, Q3: \$158.4/MWh). Assume for a moment variable operating costs of \$30/MWh and an additional \$5/MWh standby cost for regulation wear and tear. A generating unit selling 1MW at mean DA regulation up price in Q3 needed a probability of 1.5 percent to be called in real time to make the same profit with receiving the mean DA CALPX price.[14] Interestingly, for a fifth of the sample, the average regula-

[14] We calculate the profit of selling 1 MWh of real-time energy from regulation reserve as (95) +

tion, CALPX and CAISO prices are \$170/MW, \$117/MWh and \$148/MWh. Under these circumstances, the CAISO would be better off buying energy in the CALPX DA market to meet its reserve requirements.

Both the reserve and energy prices were more volatile (larger standard deviations) in Q2 than in Q3. Regulation up (Q2 and Q3) and replacement (Q2) are the only cases in which the reserve prices are more volatile than the energy prices in both quarters. Skewness in excess of zero and kurtosis well in excess of three are typical for prices in wholesale electricity markets (Knittel and Roberts [2005]) and the California reserve markets are no exception. The positive skewness is attributable to the convexity of the industry supply curve (see also the discussion below). The magnitude of outliers later in the sample is mitigated by the price caps that were in place.

4.3 Market Structure

Table 3 lists the SCs that participated in the DA reserves markets between April 1st and September 30, 2000. The 4-character SC identification codes are the ones used by CAISO during its daily operations. The SCs include the municipal utilities of the cities of Azusa (AZUA), Glendale (GLEN), Los Angeles (LDWP), Pasadena (PASA), and Vernon (VERN) in California. Southern California Edison (SCE1) and Modesto Irrigation District (MID1) are public utilities in California that also provided scheduling services. The Salt River Project (SRP1) and the Puget Sound Energy (PSE1) are public utilities in Arizona and Washington, respectively. The California Department of Water Resources (CDWR) is a state agency that coordinates water management activities. Bonneville (BPA1) is one of the four power marketing administrations within the U.S. Department of Energy. Membership to the Northern California Power Agency (NCPA) is open to municipalities, rural electric cooperatives, irrigation districts and other publicly owned entities. The CALPX (PXC1) scheduled numerous resources owned by the state's largest public utilities (Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric), as well as imports

$\pi\,(158.4 - 35)$, where π is the probability that the 1 MW of reserve is called in real time. We calculate the profit of selling 1 MWh in the CALPX as $122 - 30$.

from neighboring states. The remainder of the SCs are private entities and include the state's five largest merchant generators: Duke (DETM), Dynegy (ECH1), Mirant (SCEM), Reliant (NES1) and Williams (WESC). We will collectively refer to them as "Big 5," henceforth.

Using the bid data that we have available, we calculated each SC's share in total sales for each reserve type in Q2 and Q3 (see Table 4). Constellation (CPSC), the city of Glendale (GLEN) and the LDWP sold no Q2 reserves. El Paso (EPPS) sold no Q3 reserves. The sum of the top 4 market shares ranges between 62 percent (replacement, Q2) and 94 percent (non-spinning, Q3). The CALPX (PXC1) shares dominate regulation up and spinning in both Q2 and Q3, as well as Q2 replacement. The CDWR has the largest non-spinning shares in both quarters and Powerex (PWRX) leads Q3 replacement. The difference between the largest and the smallest among the top 4 market shares is as small as 16 percent (replacement, Q2) and as large as 59 percent (non-spinning, Q2). The share allocation among the top 4 selling SCs remains relatively the same for all the reserve types over the two periods, except for regulation up, where a 50 percent reduction in the leading share of CALPX (PXC1) is observed (62 percent in Q2, 31 percent in Q3).

We also calculated the mean hourly market share for each SC by reserve types for both quarters (Table 5). The replacement had non-zero procurements during 1,081 out of 1,668 hours in Q2 and during 1,339 out of 2,015 hours in Q3. Hence, we calculated the mean hourly replacement market shares using only hours with non-zero procurements for each quarter. The allocation of the top 4 mean hourly market shares in Table 5 are very similar to the shares we calculated based on the total sales in Table 4.

Table 6 provides the primary source of the reserves for the SCs with the largest sales: conventional hydro (HY), pumped storage hydro (HYPS),[15] combustion (CTNG), combined cycle (CCNG) and steam (STNG) natural gas turbines, as well as imports and interruptible load. The average of the PG&E Citygate and the Southern California border natural gas prices were around \$4/MMBtu (Q2) and \$5.5/MMBtu (Q3). Therefore, for a gas unit with

[15]Pumped storage hydroelectricity is a method of storing and producing electricity to supply high peak demands by moving water between reservoirs at different elevations. At times of low electrical demand, excess electrical capacity is used to pump water into the higher reservoir. When there is higher demand, water is released back into the lower reservoir through a turbine, generating hydroelectricity.

a heat rate of 10MMBtu/MWh, the fuel costs in the two quarters would be \$40/MWh and \$55/MWh. The prices for nitrogen oxide emission permits could add between \$10/MWh and \$35/MWh (Joskow and Kahn [2000]) in the units' variable costs depending on its technical characteristics. It is also widely accepted that the hydro units have a variable operating cost that is very close to zero.

Natural gas turbines are the primary reserve sellers for the "Big 5" and the city of Pasadena (PASA). The CDWR sold extensively Q2 and Q3 non-spinning from load affiliated to Southern California Edison, Q2 regulation up and replacement from pumped storage hydro, as well as Q3 replacement from imports. The CALPX (PXC1) reserve sales were exclusively from conventional and pumped storage hydro. Imports dominate the sales of Bonneville (BPA1), Powerex (PWRX) and Sempra (SETC). We do not have any additional information regarding either the nature (generation or load) or the generation mix (hydro, natural gas etc.) for imports due to information disclosure requirements of the CAISO tariff.

Finally, we constructed an average supply and an average proxy marginal cost curve for each type of reserve in Q2 and Q3. The first step to construct our average supply curve for the reserve and quarter under consideration was to horizontally sum the supply curves of all settlement periods within the quarter. We call envelope the resulting supply curve. The second step was to multiply the quantity component in each step of the envelope supply curve with the inverse of the number of settlement periods in the quarter (Figure 7).

We constructed the proxy marginal cost curve for each settlement period as in Patrick and Wolak (2001). We computed the maximum amount of MW sold by a reserve resource, which could be thought as a lower bound for the resource's capacity. We then computed the minimum price that this maximum amount of MW was sold in the quarter under consideration (obtaining an upper bound on the marginal cost of the resource). The proxy (upper bound) for the marginal cost curve for each settlement period emerged by stacking these minimum-price and maximum-quantity pairs in ascending order of their price component and aggregating. We constructed the envelope and average marginal cost curves using the underlying reasoning of their supply analogs.

The flat portions at \$0/MW in Q2 regulation up and spinning average proxy marginal cost curves are both due to hydro scheduled by the CALPX (PXC1), particularly in April and May when the spring runoff was still abundant. Their Q3 analogs are due to combustion and steam turbines scheduled by the CALPX (PXC1) and Enron (EPMI) in regulation up and spinning, respectively. If we move to non-spinning, interruptible load and combined cycle turbines scheduled by Southern California Edison (SCE1) and NCPA give rise to the \$0/MW flats in both Q2 and Q3. In the case of replacement, \$0/MW are due to Southern California Edison (SCE1) interruptible load and Coral (CRLP) in Q2, as well as standby Enron (EPMI) combustion turbines combined cycle and Reliant (NES1) combustion turbines.

4.4 Diagnosing Unilateral Market Power: Findings

Tables 8 and 9 provide the mean hourly residual demand inverse elasticities and their associated standard errors (corrected for heteroskedasticity) by SC using the arc elasticity formula, as in Wolak (2003b), for regulation up and spinning, respectively. Only three firms met our conditions for non-spinning and replacement; we summarize these results in the discussion below. The number of observations $\overline{T}_{ij}$ includes all hours for which $\left|\eta_{ijt}\right| > 1$, such that:

$$\frac{1}{\left|\widehat{\eta}_{ij}\right|} = \frac{1}{\overline{T}_{ij}} \sum_{t=1}^{\overline{T}_{ij}} \frac{1}{\left|\eta_{ijt}\right|} \leq \frac{1}{\overline{T}_{ij}} \sum_{t=1}^{\overline{T}_{ij}} \frac{p_{jt}^{e} - mc_{ijt}}{p_{jt}^{e}}, \ i \in N, \ j \in J \tag{10}$$

The number of observations $\overline{T}_{ij}$ bias downwards the number of hours during which the SC i placed a markup on reserve type j if that comes entirely from the cross price derivatives. This may be especially true for the SCs participating in the regulation market because both $\partial SO_1(\mathbf{p})/\partial p_l \leq 0$ and $\partial Q_1(\mathbf{p})/\partial p_l \geq 0$ $(l = 2, \ldots, 4)$. For the replacement market participants, on the other hand, $\partial Q_4(\mathbf{p})/\partial p_l = 0$ for $l = 1, 2, \ldots, 3$.

Our t-tests indicated that $1/\left|\widehat{\eta}_{i1}\right|$ was larger in Q2 for CDWR and the city of Pasadena (PASA). While the CDWR, Enron (EPMI) and Reliant (NES1) had larger $1/\left|\widehat{\eta}_{i2}\right|$ in Q2 than in Q3, the opposite holds for the Automated Power Exchange (APX1), the city of Azusa (AZUA) and Duke (DETM).[16] The reader should also keep in mind that the price cap of

[16] We used only those SCs for which $\overline{T}_{ij} \geq 50$ in each quarter, so that we can perform statistical inference

\$750/MW was set at \$500/MW on July 1, and subsequently to \$250/MW on August 7. The range of $1/\left|\widehat{\eta}_{i1}\right|$ is between 0.10 for the city of Pasadena (PASA) in Q3 and 0.25 for Duke (DETM) in Q2. Similarly, $1/\left|\widehat{\eta}_{i2}\right|$ is as low as 0.14 for Duke (DETM) in Q3 and as high as 0.37 for CALPX (PXC1), also in Q3. Finally, the Q2 $1/\left|\widehat{\eta}_{i3}\right|$ and $1/\left|\widehat{\eta}_{i4}\right|$ for the Automated Power Exchange (APX1) are 0.27 and 0.12, respectively. As a measure of comparison, Wolak (2003b) reports mean Lerner indices between 0.10 and 0.19 for the "Big 5" in the imbalance energy market between June and September 2000.

For every SC, we calculated the product of MW sold times its markup for each settlement period during which $\left|\widehat{\eta}_{ijt}\right| > 1$ and we took the sum of these products over $\overline{T}_{ij}$, which we call transfer to the SC. The Q2 non-spinning and Q2 replacement transfers to the Automated Power Exchange (APX1), which were among the largest, add up to about \$2.5m. The total regulation up transfers are \$1.6m (Q2) and \$1.8m (Q3). The same calculations in spinning lead to \$3.3m (Q2) and \$5.2 (Q3). In Q2 non-spinning and replacement, the transfers sum to \$0.9m and \$1.5m, respectively. Our biased transfer estimates for all products add up to \$14m.[17]

The issue that naturally arises is why the various SCs managed to exercise significant unilateral market power in the reserves market over the six-month period analyzed. Some of the answers lie in the findings of earlier studies that focused exclusively on the state's energy markets. Tight supply and virtually inelastic demand along with the lack of substantial forward contracting on behalf of the state's largest utilities have been identified as the key factors of the skyrocketing energy prices in the summer of 2000. There is no doubt about the detrimental effect of the same factors on the reserve markets, which are closely related to the energy market, as we discussed above. In addition, the reserve markets were highly concentrated. The sum of the four largest market shares is at least 60 percent (replacement, Q3) and in some cases exceeds 90 percent (e.g., non-spinning), as Table 6 illustrates.

Some additional answers lie on the design of the reserves market, which gave rise to a principal agent relationship. The CAISO (agent) bought reserves on behalf of any SC

with sufficient degrees of freedom.

[17] The transfers for other two firms for (APS1 and AEI1) add up to less than \$4,000 and less than \$7,000 for non-spinning and replacement, respectively.

(principal) equal to the fraction of its assigned share of the total CAISO requirement that could not self-provide from other SCs that had a surplus of reserves. The CAISO did not make any payments, but instead billed the SC on behalf of which bought reserves within 45 days of its transactions. This lack of financial responsibility of the CAISO for its procurements along with the strict performance criteria that its operations had to conform with gave the SCs on the supply side plenty of room to markup their prices. For example, on June 13th 2000, the CAISO faced one of its tightest system conditions. During hour 11, $1/\left|\eta_{1jt}\right|$ for Dynegy (ECH1) was 0.55 which at the market clearing price of \$550/MW, and a residual demand of 307MW generated a transfer of \$90,000.

5 Conclusion

We examine for the first time the allocative efficiency of a reserves market in a restructured wholesale electricity industry using data from California. We replicate market outcomes with a high degree of precision using largely neglected information released during the FERC investigation of the state's crisis in 2000 and 2001. We calculate the inverse elasticities of the market participants' residual demand curves for four types of reserves employing the model of expected profit maximizing bidding behavior of Wolak (2000). These inverse elasticities provide only a lower bound for the extent of the sellers' price-cost margin for the period that we analyze: the second and third quarters of 2000. This is because they do not account for a feature of the markets operations, namely hierarchical substitutability of the products. High concentration, along with a principal-agent relationship that emerged from the market design, generated millions of dollars in transfers to limited number of reserve sellers. Our calculations establish markup lower bounds in the neighborhood of 20 percent for the two highest quality types of reserves: regulation up and spinning.

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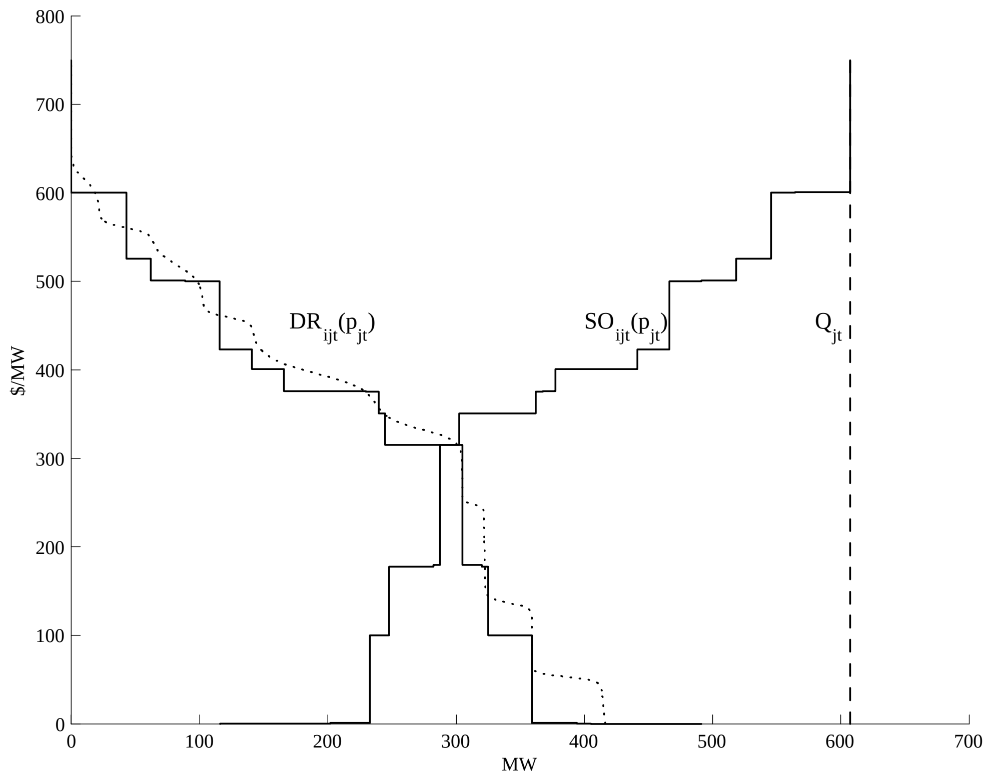
A Figures and Tables

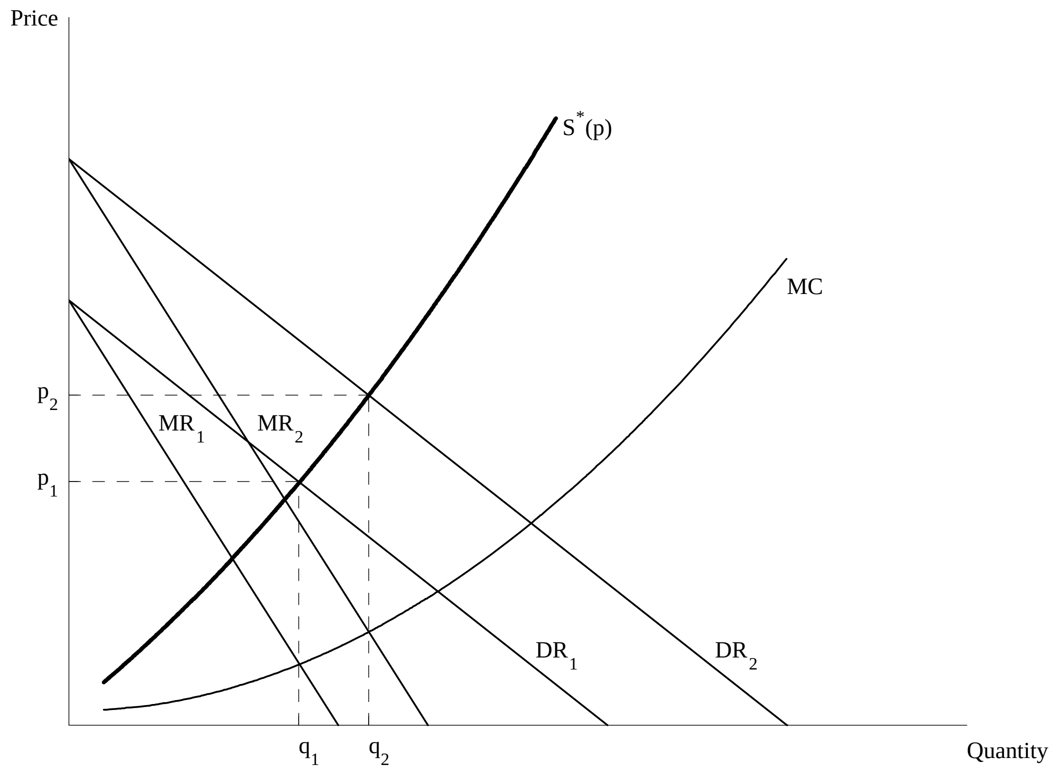
A.1 Figures

Figure 1: Example of a residual demand curve



Note: The solid non-increasing line is the residual demand, $DR_{ijt}(p_{jt})$. The dotted non-increasing line is the smoothed residual demand curve using a standard normal kernel as in Wolak (2003a). The solid non-decreasing line is the supply of all other scheduling coordinators, $SO_{ijt}(p_{jt})$. The vertical dashed line represents the CAISO procurement Q_{jt}.

Figure 2: Example of an expected profit maximizing curve $S^*(p)$



Note: For residual demand realization DR_1, the firm chooses (q_1, p_1). For residual demand realization DR_2, the firm chooses (q_2, p_2). Analogous intuition gives rise to price and quantity combinations traced out by $S^*(p)$, assuming additive shocks to the intercept of the residual demand curve as in Hortaçsu and Puller (2007).

Figure 3: Reserve market procured quantities

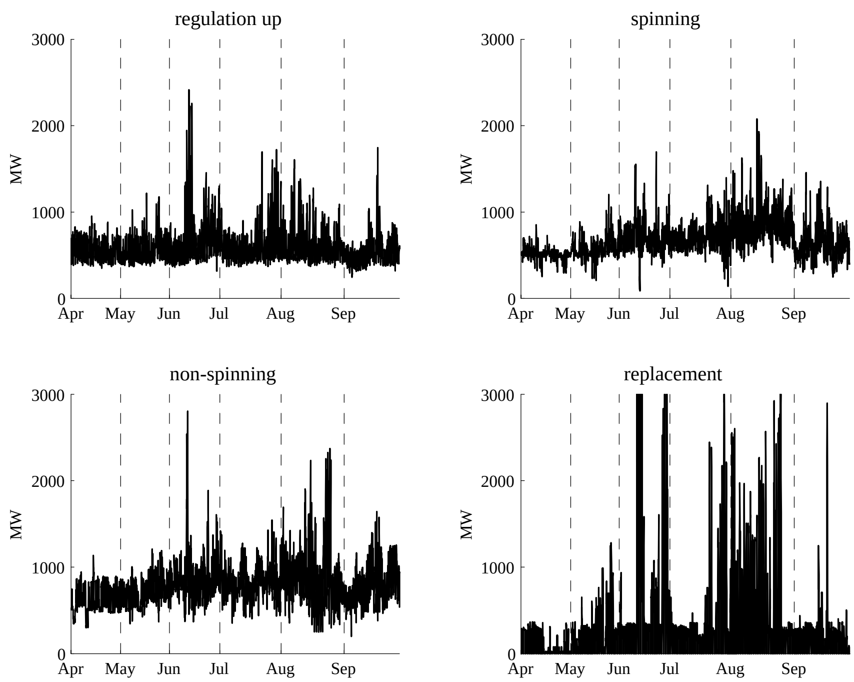


Figure 4: Reserve market clearing prices

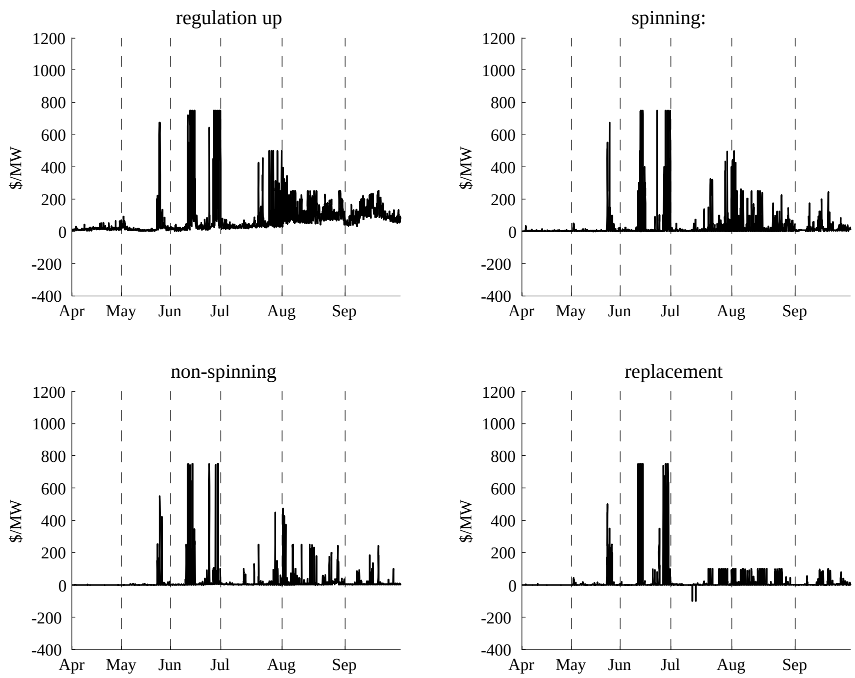


Figure 5: Energy procurements, load schedules and deviations

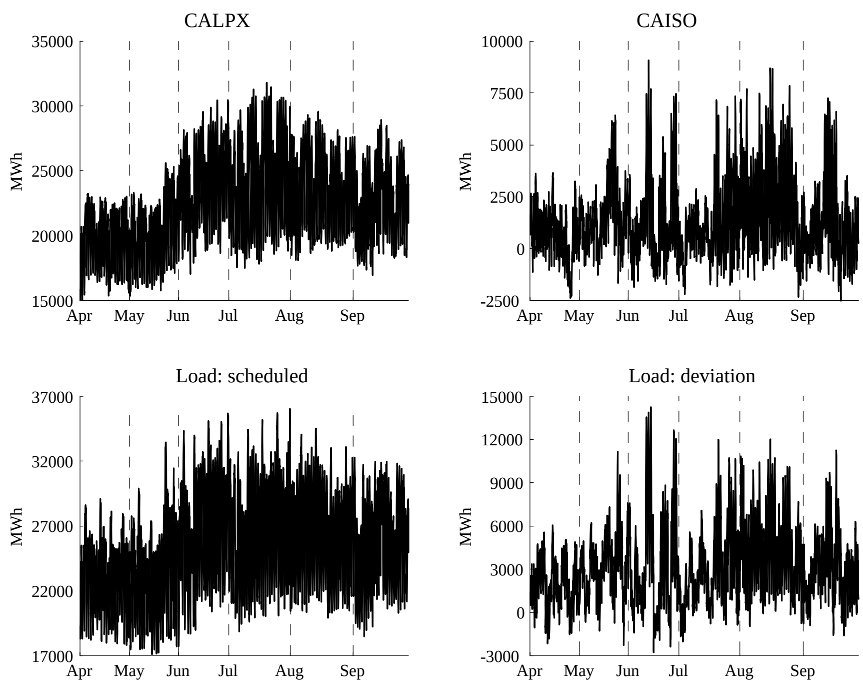


Figure 6: Energy market clearing prices

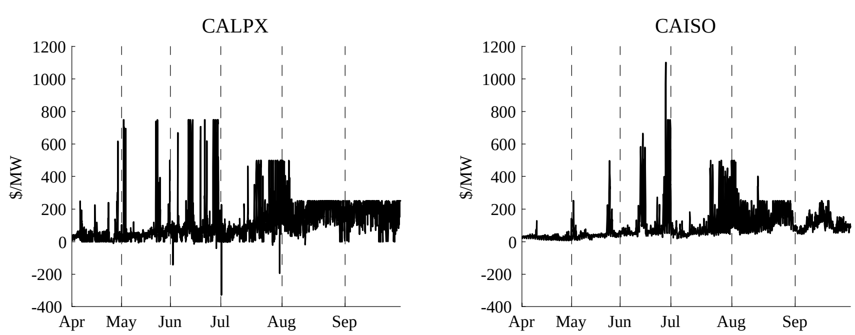


Figure 7: Envelope and average supply curves with two settlement periods

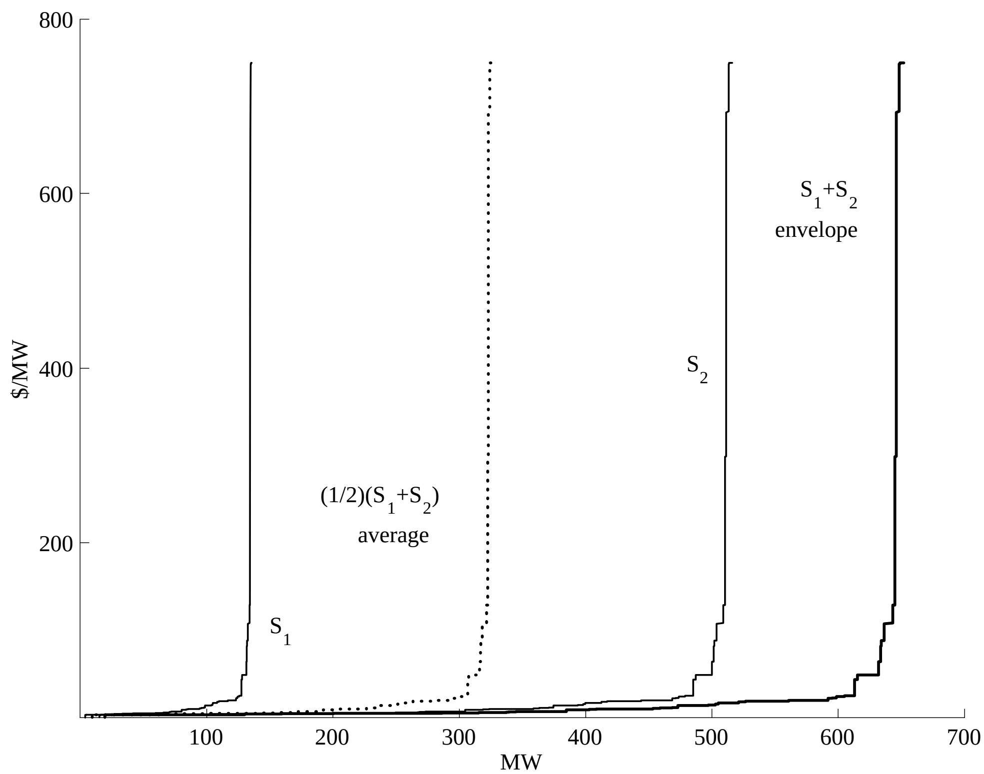


Figure 8: **Q2** mean hourly supply and proxy marginal cost curves

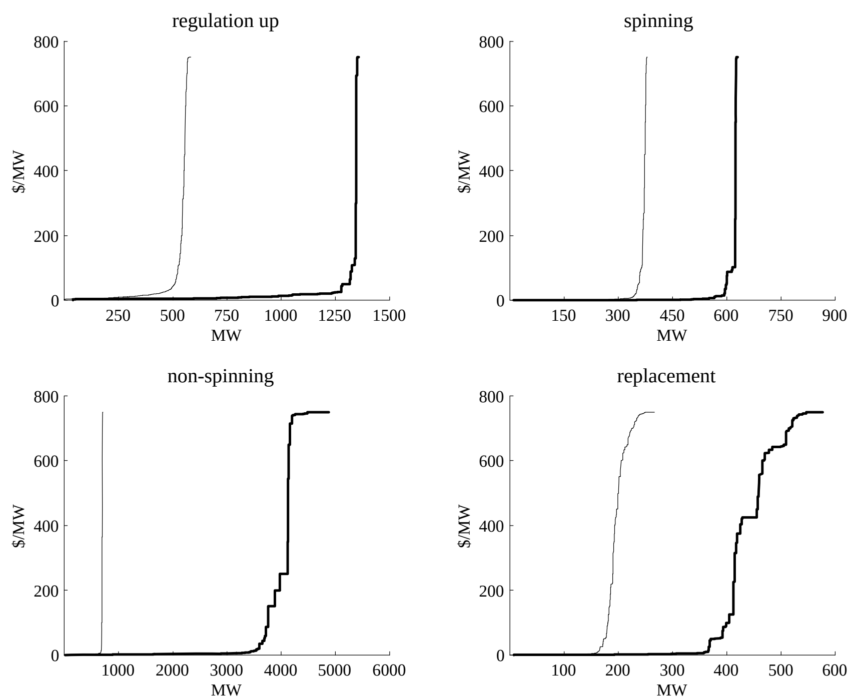


Figure 9: **Q3** mean hourly supply and proxy marginal cost curves

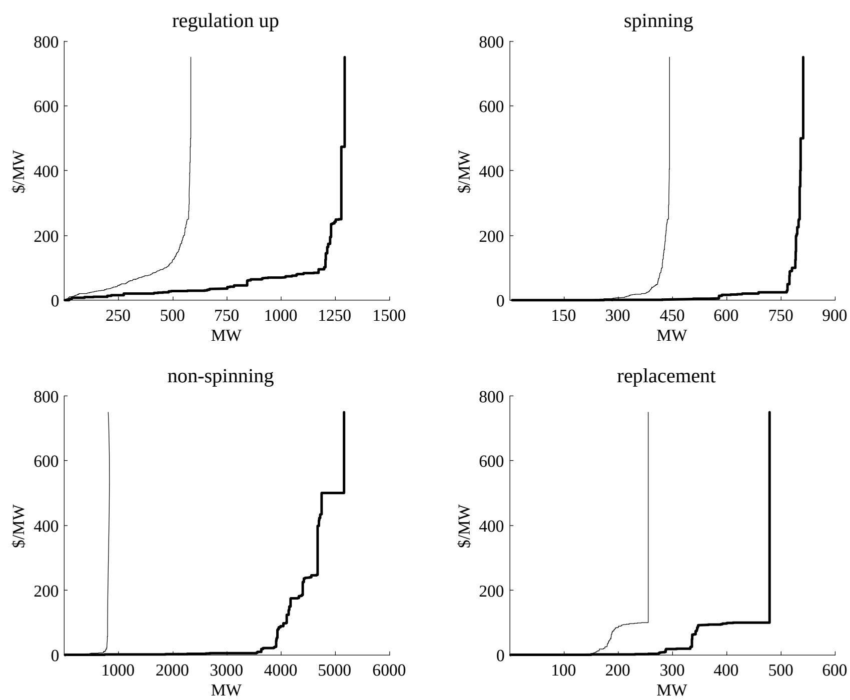


Table 1: Reserve summary statistics

	ru:Q2		**sp:Q2**		**ns:Q2**		**rp:Q2**	
	MCQ	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**
min	313.5	4.8	86.0	0	300.0	0	0	0
mean	583.7	65.1	597.7	30.1	735.1	24.8	319.3	32.6
max	2413.9	750	1691.9	750	2804.5	750	6176.6	750
median	535.2	16.5	555.6	3.5	732.9	0	133	0
std.dev	194.5	160.7	147.6	113.0	220.6	113.7	740.5	135.6
skewenes	3.0	3.6	1.8	5.3	2.5	5.6	5.1	4.6
kurtosis	19.6	14.6	10.9	31.9	19.3	33.7	31.7	23.6
	ru:Q3		**sp:Q3**		**ns:Q3**		**rp:Q3**	
	MCQ	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**
min	241.9	13.8	141	0.9	200	0	0	-99
mean	583.6	95.6	735.1	28.1	848.6	14.9	360.7	12.1
max	1742.5	500	2075.2	498.0	2370	475	3339	100.0
median	547.1	77	707.8	8.0	812.7	3.9	228	1.1
std.dev	191.4	72.3	218.5	56.5	266.8	42.2	552.3	28.8
skewenes	2.1	2.2	1.2	4.0	1.3	5.5	2.6	2.1
kurtosis	9.6	10.5	6.9	22.3	6.9	39.5	10.3	7.5
	ru:all		**sp:all**		**ns:all**		**rp:all**	
	MCQ	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**	**MCQ**	**MCP**
min	241.9	4.8	86.0	0.0	200.0	0.0	0.0	-99.0
mean	583.7	81.8	672.9	29.0	797.2	19.4	342.0	21.4
max	2413.9	750.0	2075.2	750.0	2804.5	750.0	6167.6	750.0
median	541.8	40.1	636.4	5.0	768.5	2.1	194.7	0.6
std.dev	192.8	121.5	201.7	86.8	253.3	82.8	644.6	94.3
skewenes	2.5	3.7	1.5	6.0	1.7	7.1	4.4	6.6
kurtosis	14.3	19.1	7.8	44.0	9.9	57.5	27.7	48.9

Notes: ru: regulation up; sp: spinning; ns: non-spinning; rp: replacement

MCQ: market procured quantity; MCP: market clearing price

Table 2: Energy summary statistics

	CALPX:Q2		CAISO:Q2		Load:Q2	
	MCQ	**MCP**	**MCQ**	**MCP**	**Sch.**	**Dev.**
min	15035	6.8	−2375	−142.6	17108	−2765
mean	21521	74.2	1213	81.9	24789	2851
max	30466	1100	9065	750	35691	14253
median	21406	39.9	985	44	24648	2396
std.dev	3363	122	1658	145.2	4190	2734
skewenes	0.4	4.6	1.2	3.7	0.3	1.1
kurtosis	2.6	28.1	5.2	16.2	2.4	5
	CALPX:Q3		**CAISO:Q3**		**Load:Q3**	
	MCQ	**MCP**	**MCQ**	**MCP**	**Sch.**	**Dev.**
min	16932	17.9	−2553	−325.6	18462	−2036
mean	23738	122.5	1500	158.4	26623	3440
max	31785	500	8695	500.0	36062	12020
median	24127	95	1038	142.9	27174	2989
std.dev	3399	83	2059	101.4	3950	2699
skewenes	0	1.8	0.9	1.0	−0.1	0.7
kurtosis	2	7.1	3.4	5.1	1.8	3.0
	CALPX: all		**CAISO: all**		**Load: all**	
	MCQ	**MCP**	**MCQ**	**MCP**	**Sch.**	**Dev.**
min	15035	6.8	−2553	−325.6	17108	−2765
mean	22734	100.6	1377	123.7	25792	3174
max	31785	1100	9065	750	36032	14253
median	22372	65	1017	82	25694	2733
std.dev	3558	105.3	1893	128.9	4161	2730
skewenes	0.1	3.5	1.1	2.4	0	0.9
kurtosis	2.2	2.9	4.1	10.6	2	3.8

Notes: MCQ: market clearing quantity; MCP: market clearing price
Sch: scheduled; Dev: deviation

Table 3: List of Scheduling Coordinators

SC ID	**SC Full Name**
AEI1	Avista Energy
APS1	Arizona Public Services
APX1	Automated Power Exchange, Inc.
AZUA	City of Azusa
BPA1	Bonneville Power Administration
CDWR	California Dept. of Water Resources
CPSC	Constellation Power Source, Inc.
CRLP	Coral Power, LLC
DETM	Duke Energy Trading and Marketing, LLC
ECH1	Dynegy Electric Clearinghouse
EPMI	Enron Power Marketing, Inc.
EPPS	El Paso Power Services Company
GLEN	City of Glendale
KET3	Entergy-Koch Energy Trading, Inc.
LDWP	Los Angeles Dept. of Water and Power
MID1	Modesto Irrigation District
NCPA	Northern California Power Agency
NES1	Reliant Energy Services
PASA	City of Pasadena
PORT	Portland General Electric
PSE1	Puget Sound Energy
PWRX	Powerex
PXC1	California Power Exchange (CALPX)
SCE1	Southern California Edison
SCEM	Southern Company Energy Marketing, LP
SETC	Sempra Energy Trading Company
SRP1	Salt River Project
VERN	City of Vernon
WESC	Williams Energy Services, Corp.

Table 4: Total market shares (percentage)

SC ID	**ru:Q2**	**sp:Q2**	**ns:Q2**	**rp:Q2**	**ru:Q3**	**sp:Q3**	**ns:Q3**	**rp:Q3**
AEI1	*null*	*null*	*null*	0.859	*null*	0.063	0.004	2.667
APS1	*null*	0.060	0.051	1.286	*null*	*null*	*null*	0.089
APX1	*null*	7.448	*null*	0.140	*null*	3.080	*null*	0.048
AZUA	*null*	0.002	*null*	0.115	*null*	0.002	*null*	0.024
BPA1	*null*	12.316	0.671	1.228	*null*	13.523	0.531	0.963
CDWR	7.075	0.832	61.407	10.236	5.984	3.157	55.236	7.872
CPSC	*null*	*null*	*null*	*null*	*null*	*null*	*null*	0.296
CRLP	*null*	0.001	*null*	0.280	*null*	2.005	0.036	0.688
DETM	8.961	0.360	0.227	1.993	21.748	0.410	0.160	0.591
ECH1	9.956	1.292	18.080	7.219	16.985	2.818	7.047	9.195
EPMI	*null*	4.378	0.279	4.516	*null*	3.952	0.407	5.070
EPPS	*null*	0.004	*null*	*null*	*null*	*null*	*null*	*null*
GLEN	*null*	*null*	*null*	*null*	*null*	0.008	*null*	*null*
KET3	*null*	*null*	*null*	0.349	*null*	0.003	0.003	*null*
LDWP	*null*	*null*	*null*	*null*	0.692	*null*	*null*	*null*
MID1	*null*	*null*	*null*	3.017	*null*	*null*	*null*	3.425
NCPA	*null*	*null*	1.284	1.750	*null*	*null*	0.459	3.011
NES1	5.122	0.682	0.771	6.256	6.099	0.948	0.239	0.103
PASA	1.370	1.120	2.003	1.719	0.908	1.761	2.344	2.111
PORT	*null*	0.170	0.005	*null*	*null*	0.187	0.026	*null*
PSE1	*null*	5.322	*null*	6.830	*null*	1.412	0.035	0.083
PWRX	*null*	3.972	0.219	21.443	*null*	8.659	1.028	29.004
PXC1	61.904	54.278	10.693	22.639	31.361	49.921	29.492	25.441
SCE1	*null*	*null*	1.789	0.738	*null*	*null*	0.870	0.394
SCEM	0.037	0.072	0.068	2.848	7.258	0.309	0.050	4.104
SETC	*null*	6.414	0.542	0.380	*null*	5.814	0.898	3.583
SRP1	*null*	0.017	*null*	*null*	*null*	0.355	*null*	*null*
VERN	*null*	*null*	*null*	0.236	*null*	*null*	*null*	0.459
WESC	5.575	1.261	1.910	3.924	8.966	1.612	1.134	0.780

Note: ru: regulation up; sp:spinning; ns: non-spinning; rp: replacement

Table 5: Mean hourly market shares (percentage)

SC ID	**ru:Q2**	**sp:Q2**	**ns:Q2**	**rp:Q2**	**ru:Q3**	**sp:Q3**	**ns:Q3**	**rp:Q3**
AEI1	*null*	*null*	*null*	0.236	*null*	0.047	0.005	1.662
APS1	*null*	0.073	0.038	0.716	*null*	*null*	*null*	0.533
APX1	*null*	8.186	*null*	0.230	*null*	3.383	*null*	0.050
AZUA	*null*	0.001	*null*	0.030	*null*	0.001	*null*	0.006
BPA1	*null*	11.537	0.601	0.224	*null*	13.616	0.595	0.391
CDWR	7.355	0.880	61.246	18.200	6.355	3.143	55.799	15.440
CPSC	*null*	*null*	*null*	*null*	*null*	*null*	*null*	0.461
CRLP	*null*	0.001	*null*	0.089	*null*	1.808	0.727	0.453
DETM	9.441	0.250	0.153	0.291	23.333	0.260	0.126	0.134
ECH1	9.346	1.170	19.704	21.730	15.884	2.461	7.462	5.042
EPMI	*null*	4.500	0.281	4.126	*null*	3.579	0.346	5.145
EPPS	*null*	0.004	*null*	*null*	*null*	*null*	*null*	*null*
GLEN	*null*	*null*	*null*	*null*	*null*	0.010	*null*	*null*
KET3	*null*	*null*	*null*	0.053	*null*	0.003	0.002	*null*
LDWP	*null*	*null*	*null*	*null*	0.574	*null*	*null*	*null*
MID1	*null*	*null*	*null*	3.188	*null*	*null*	*null*	6.783
NCPA	*null*	*null*	1.275	2.627	*null*	*null*	0.438	3.439
NES1	4.006	0.449	0.459	1.147	5.573	0.549	0.184	0.219
PASA	1.401	1.138	1.929	1.362	0.937	1.856	2.565	1.712
PORT	*null*	0.161	0.006	*null*	*null*	0.165	0.027	*null*
PSE1	*null*	4.710	*null*	4.933	*null*	1.415	0.038	0.029
PWRX	*null*	3.910	0.157	13.363	*null*	8.748	1.119	20.018
PXC1	63.380	55.319	10.160	21.896	31.529	50.288	28.202	31.933
SCE1	*null*	*null*	1.727	2.909	*null*	*null*	0.802	0.829
SCEM	0.040	0.071	0.023	0.350	6.067	0.237	0.053	1.109
SETC	*null*	6.417	0.542	0.105	*null*	6.069	0.889	3.964
SRP1	*null*	0.021	*null*	*null*	*null*	0.392	*null*	*null*
VERN	*null*	*null*	*null*	0.059	*null*	*null*	*null*	0.309
WESC	5.031	1.204	1.700	2.137	9.746	1.967	1.320	0.339

Note: ru: regulation up; sp:spinning; ns: non-spinning; rp: replacement

Table 6: Total market shares: top 4

regulation up					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	61.904	N/A	PXC1	31.361	HY
ECH1	9.956	STNG	DETM	21.748	STNG
DETM	8.961	STNG	ECH1	16.985	STNG
CDWR	7.075	HYPS	WESC	8.966	STNG
spinning					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	54.278	HY	PXC1	49.921	HY
BPA1	12.316	Imports	BPA1	13.523	Imports
APX1	7.448	other	PWRX	8.659	Imports
SETC	6.414	Imports	SETC	5.814	Imports
non-spinning					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
CDWR	61.407	Load	CDWR	55.236	load
ECH1	18.080	CTNG	PXC1	29.492	HYPS
PXC1	10.693	HYPS	ECH1	7.047	CTNG
PASA	2.003	CTNG	PASA	2.344	CTNG
replacement					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	22.639	HYPS	PWRX	29.004	Imports
PWRX	21.443	Imports	PXC1	25.441	HY
CDWR	10.236	HYPS	ECH1	9.195	STNG
ECH1	7.219	CCNG	CDWR	7.872	STNG

Table 7: Mean hourly market shares: top 4

regulation up					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	63.380	N/A	PXC1	31.529	HY
DETM	9.441	STNG	DETM	23.333	STNG
ECH1	9.346	STNG	ECH1	15.884	STNG
CDWR	7.355	HYPS	WESC	9.746	STNG
spinning					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	55.319	HY	PXC1	50.288	HY
BPA1	11.537	Imports	BPA1	13.616	Imports
APX1	8.186	N/A	PWRX	8.748	Imports
SETC	6.417	Imports	SETC	6.069	Imports
non-spinning					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
CDWR	61.246	Load	CDWR	55.799	Load
ECH1	19.704	CTNG	PXC1	28.202	HYPS
PXC1	10.160	HYPS	ECH1	7.462	CTNG
PASA	1.929	CTNG	PASA	2.565	CTNG
replacement					
Q2			**Q3**		
SC	**%**	**pr. source**	**SC**	**%**	**pr. source**
PXC1	21.896	HYPS	PXC1	31.933	HY
ECH1	21.730	CTFO	PWRX	20.018	Imports
CDWR	18.200	HYPS	CDWR	15.440	HYPS
PWRX	13.363	Imports	MID1	6.783	Imports

Table 8: Mean inverse elasticities: regulation up

	Q2				Q3			
SC	$\overline{T}_{i1}$	$\frac{1}{\lvert\widehat{\eta}_{i1}\rvert}$	**t-ratio**	**Transfer($)**	$\overline{T}_{i1}$	$\frac{1}{\lvert\widehat{\eta}_{i1}\rvert}$	**t-ratio**	**Transfer($)**
AEI1	*null*	–	–	–	*null*	–	–	–
APS1	*null*	–	–	–	*null*	–	–	–
APX1	*null*	–	–	–	*null*	–	–	–
AZUA	*null*	–	–	–	*null*	–	–	–
BPA1	*null*	–	–	–	*null*	–	–	–
CDWR	78	0.24	9.49	313,117	80	0.17	9.41	144,888
CPSC	*null*	–	–	–	*null*	–	–	–
CRLP	*null*	–	–	–	*null*	–	–	–
DETM	60	0.25	8.37	59,609	121	0.24	12.95	474,682
ECH1	74	0.18	8.86	180,198	64	0.24	8.58	348,917
EPMI	*null*	–	–	–	*null*	–	–	–
EPPS	*null*	–	–	–	*null*	–	–	–
GLEN	*null*	–	–	–	*null*	–	–	–
KET3	*null*	–	–	–	*null*	–	–	–
LDWP	*null*	–	–	–	8	0.07	1.75	29,541
MID1	*null*	–	–	–	*null*	–	–	–
NCPA	*null*	–	–	–	*null*	–	–	–
NES1	30	0.20	4.89	278,327	56	0.13	9.36	122,871
PASA	94	0.15	10.62	73,168	151	0.10	11.43	117,857
PORT	*null*	–	–	–	*null*	–	–	–
PSE1	*null*	–	–	–	*null*	–	–	–
PWRX	*null*	–	–	–	*null*	–	–	–
PXC1	36	0.32	6.74	536,204	87	0.19	9.99	386,053
SCE1	*null*	–	–	–	*null*	–	–	–
SCEM	52	0.12	9.03	5,026	22	0.12	5.38	96,870
SETC	*null*	–	–	–	*null*	–	–	–
SRP1	*null*	–	–	–	*null*	–	–	–
VERN	*null*	–	–	–	*null*	–	–	–
WESC	21	0.21	4.05	138,609	26	0.21	4.69	73,562
Overall	445	0.21	20.73	1,584,258	615	0.16	24.37	1,795,240

Table 9: Mean inverse elasticities: spinning

		Q3				Q3		
SC	$\overline{T}_{i2}$	$\frac{1}{\lvert\widehat{\eta}_{i2}\rvert}$	**t-ratio**	**Transfer($)**	$\overline{T}_{i2}$	$\frac{1}{\lvert\widehat{\eta}_{i2}\rvert}$	**t-ratio**	**Transfer($)**
AEI1	*null*	–	–	–	17	0.15	5.41	9,307
APS1	12	0.34	3.88	99,416	*null*	–	–	–
APX1	731	0.28	28.79	328,614	913	0.23	32.27	312,369
AZUA	4	0.17	3.39	5,746	6	0.08	2.00	2,765
BPA1	214	0.34	18.56	836,005	273	0.31	20.90	738,491
CDWR	150	0.20	10.60	27,624	621	0.24	24.40	361,990
CPSC	*null*	–	–	–	*null*	–	–	–
CRLP	*null*	–	–	–	515	0.23	25.11	206,248
DETM	71	0.33	12.47	80,059	176	0.14	9.10	69,816
ECH1	526	0.18	21.45	84,644	286	0.20	16.14	309,598
EPMI	580	0.20	21.91	102,935	565	0.26	27.05	584,330
EPPS	8	0.32	3.48	1,029	*null*	–	–	–
GLEN	*null*	–	–	–	*null*	–	–	–
KET3	*null*	–	–	–	*null*	–	–	–
LDWP	*null*	–	–	–	8	0.01	4.49	7
MID1	*null*	–	–	–	*null*	–	–	–
NCPA	*null*	–	–	–	*null*	–	–	–
NES1	50	0.13	6.44	26,242	151	0.19	13.45	293,076
PASA	527	0.21	22.81	282,509	685	0.20	27.40	175,186
PORT	28	0.22	5.37	68,095	36	0.17	4.79	23,072
PSE1	209	0.35	17.60	304,492	91	0.31	11.64	76,817
PWRX	206	0.32	20.82	142,597	206	0.33	16.74	440,807
PXC1	272	0.35	19.97	483,641	364	0.37	24.98	1,070,606
SCEM	186	0.24	13.04	9,261	53	0.25	8.69	37,150
SETC	708	0.28	31.72	378,631	818	0.28	33.36	380,156
SRP1	*null*	–	–	–	92	0.22	12.13	16,371
VERN	*null*	–	–	–	*null*	–	–	–
WESC	91	0.25	10.15	75,306	170	0.26	15.44	58,991
Overall	4573	0.24	71.13	3,336,845	6046	0.23	83.49	5,167,152