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Paul Joskow* and Edward Kahn**

February 4, 2002[1]

1. Introduction

During the Summer of 2000, wholesale electricity prices in California were nearly 500% higher than they were during the same months in 1998 or 1999. This explosion of prices was unexpected (CEC, 2000) and has called into question whether electricity restructuring will bring the benefits of competition promised to consumers. Federal and State government officials have initiated investigations and issued reports about the behavior and performance of California's wholesale electricity market.[2] Unlike previous price spikes observed in other US wholesale electricity markets, the California experience has not been a transient phenomenon of a few days' duration, but a persistent series of events lasting from June 2000 through roughly mid-June 2001.[3] This paper covers only the Summer months of 2000, with more intensive analysis of the month of June 2000, when most generating units should have recently returned from service from their Spring

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[1] This paper integrates and updates analyses contained in Joskow and Kahn (2001a and b).

[2] Reports include FERC Staff Report (2000), Kahn and Lynch (2000), California Independent System Operator Department of Market Analysis (2000), California Power Exchange Corporation Compliance Unit (2000) among others.

[3] FERC (1998) gives a detailed account of price spikes in Midwestern markets in 1998. Price spikes in the Eastern US during 1999 were related to reliability problems of various kinds (DOE, 2000).

maintenance outages and future developments in supply and demand conditions are unlikely to have been anticipated by suppliers.[4]

The purpose of this paper is to examine the factors that explain this increase in wholesale electricity prices. There were a number of changes in supply and demand conditions in 2000 that would suggest that prices should have been expected to increase from the previous years: natural gas prices increased, demand increased, and power imports available to California decreased in 2000 compared to 1998 and 1999. The first objective of this paper is to determine how much of the observed price increases can be explained by these three "market fundamentals," *assuming* that the wholesale power market is perfectly competitive. We do so by simulating competitive benchmark prices given these supply and demand factors prevailing over the Summer of 2000 and then compare the simulated competitive benchmark prices with the actual prices observed. We find that while these three supply and demand factors can explain a portion of the observed increase in prices, there is still a large gap between the observed prices and simulated competitive benchmark prices.

The second objective of this paper is to determine whether and how much of this residual can be explained by the prices of tradeable permits for NOx emissions. These emissions permits must be held by generating plants and other affected sources in the South Coast Air Quality Management District (SCAQMD) pursuant to the Regional Clean Air Initiatives Market (RECLAIM) program.[5] The prices for these emissions permits increased dramatically during the Summer of 2000 compared to earlier periods. Including the emissions permit prices in the supply costs of those generators subject to RECLAIM increases competitive benchmark prices for electricity significantly, especially by the end of the Summer 2000. However, even after taking account of NOx permit costs, during most of the Summer there remains a large gap between the simulated benchmark prices and actual market prices. We tentatively attribute this gap to market power and related market imperfections associated with the structure of California's wholesale electricity markets.

The final objective of this paper is to examine whether our attribution of the observed gap between benchmark competitive prices and actual prices is consistent with available data on supplier behavior. Even in a perfectly competitive market, prices may rise above the relevant short-run marginal cost when demand must be rationed by prices

[4] Prices in California remained remarkably high in October and November, then reached unprecedented levels during December 2000 and remained at those levels through the Winter and Spring months of 2001. The latter part of this period was also accompanied by an order of magnitude increase in gas prices, the evaporation of imports from the Northwest, a large fraction of California's generating capacity was unavailable to supply due to planned or forced outages, some of which were mandated by environmental regulators, new regulatory interventions, and utility credit problems that may have made some suppliers reluctant to supply voluntarily. It is clear that by late 2000, the normal functioning of the wholesale electricity markets had completely broken down. Joskow (2001) discusses price movements and various government initiatives for this entire period.

[5] We have not examined air quality regulations that may restrict production through command-and-control regulations. It is our impression that such regulations are not binding in California.

above marginal cost to balance supply and demand in the face of capacity constraints. However, there are good reasons to believe that the attributes of electricity supply and demand--non-storability, very low (zero) short-run demand elasticity, capacity constraints, and (in California) a large fraction of demand being satisfied in the spot market—create opportunities for suppliers acting unilaterally to withhold output from the market profitably to drive up prices when demand is high. Collusion is not necessary for firms to exercise market power under these conditions. Therefore the diagnosis of market power should include both an analysis of price/marginal cost margins and a companion analysis of supplier behavior. Accordingly, we examine whether potentially profitable generating capacity was withheld from the market during high-price hours.

Public data on the production of most steam units are available on an hourly basis from the Environmental Protection Agency (EPA). Southern California Edison supplied us with information from the WSCC on hourly generation for Long Beach.[6] In addition, information of the real-time dispatch of GTs is available from the California Independent System Operator (CAISO). We show that during high demand periods in California it is profitable for suppliers holding a portfolio of generating units with diverse marginal supply costs to withdraw capacity from the market even under otherwise competitive conditions. Our examination of the data shows that a significant amount of generating capacity produced much less energy than could have been produced at marginal costs below observed market clearing prices. This behavior cannot be explained by the CAISO's procurement of ancillary services. Therefore, either the units were suffering from unusual operational problems or they were being withheld from the market to increase prices.[7] Interestingly, the one supplier for which we do not find any significant evidence of withholding had apparently contracted most of the output of its capacity forward and would not have benefited by driving up spot market prices by withholding output.

[6] We discuss the comparability of these data sources below. The WSCC data are available to all members of the WSCC for a nominal price. The EPA data are available on the EPA's website.

[7] The data available to us are not sufficient to measure supplier withholding behavior by generators located outside of the CAISO. Nor can we measure the control over generation supplies acquired by wholesale market aggregators or their bidding and supply behavior. Yet, as we will demonstrate, net imports into California can have significant effects on market-clearing prices. These imports declined significantly in Summer 2000 compared to Summer 1999 and wholesale marketers were likely to have been active participants as buyers and sellers in the California markets. It is possible that generators, or wholesale market aggregators, controlling supplies from generating units outside of California may also have the incentive and ability to increase wholesale market prices in California (and the rest of the WSCC). Accordingly, a complete and definitive picture of wholesale market behavior and performance in California this past summer, and the effects of strategic behavior by suppliers with market power, requires an analysis of demand and supply conditions in those portions of the WSCC that historically have provided the bulk of the net supplies to California. Such an analysis should also take account the control over generation supplies accumulated by wholesale marketers operating in the WSCC. The information necessary to perform this analysis is neither publicly available nor available to the CAISO. This is the area where additional data collection and appropriate empirical analysis by responsible regulatory agencies can provide value-added to the extensive analysis of market behavior and performance of California suppliers that has been completed over the last two years.

A number of previous studies have examined wholesale electricity prices in California and found some evidence of market power, especially during high demand periods. Most of this analysis relies on confidential data available only to the CAISO or to the California Power Exchange (PX). In addition to extending this kind of analysis to the Summer of 2000, our paper provides three innovations. First, it relies on data which are generally available to the public rather than on confidential data available only to the CAISO or PX and their respective market surveillance committees. Second, previous analyses of wholesale market prices in California have not systematically taken into account the prices for NOx emissions permits which generating plants located in the Los Angeles area must hold to cover their emissions of NOx. Third, we introduce a complementary analysis of unit level output behavior to determine whether capacity was strategically withheld.

2. Background

The California market institutions in place in the Summer of 2000 were introduced in April 1998 after four years of debate about electricity sector restructuring and the design and creation of complex new wholesale market institutions. Under California's electricity restructuring and deregulation program, wholesale market prices were intended to be "market-based."[8] The non-profit CAISO was created to operate the transmission networks owned by the state's Investor Owned Utilities (IOUs) and the PX was created to operate day-ahead hourly auction markets for wholesale electrical energy.[9] The CAISO was also given the responsibility to operate hourly auction markets for reserves (ancillary services) and imbalance energy and to manage congestion. All supply from generators selling into the CAISO control area and all demand by "load-serving entities" located in the CAISO control area must ultimately be physically scheduled with or dispatched by CAISO.

Energy to meet California loads comes from both in-state generators and out-of-state generators. The in-state generators consist of four nuclear power plants, hydro-electric plants that are located primarily in Northern California, gas-fired steam and peaking turbines, and cogenerators and other generation sources that are "Qualifying Facilities" (QFs) under the Public Utility Regulatory Policy Act of 1978 (PURPA). About half of in-state generating capacity consists of gas-fired steam and peaking units and these units are the marginal supply sources during most hours in the Summer when electricity demand in California is highest. These units were sold by the three incumbent utilities in 1998 and 1999 to five independent power companies and these new "merchant generators" owned these units during the period we study. It is fairly easy to measure the marginal costs of these units since their thermal efficiencies at different output levels are well known and spot market prices for natural gas are available from a variety of sources. No new generating capacity has entered the California market between the time these generating units were divested and the period we study; most of this gas-fired capacity dates back to the 1960s and 1970s.

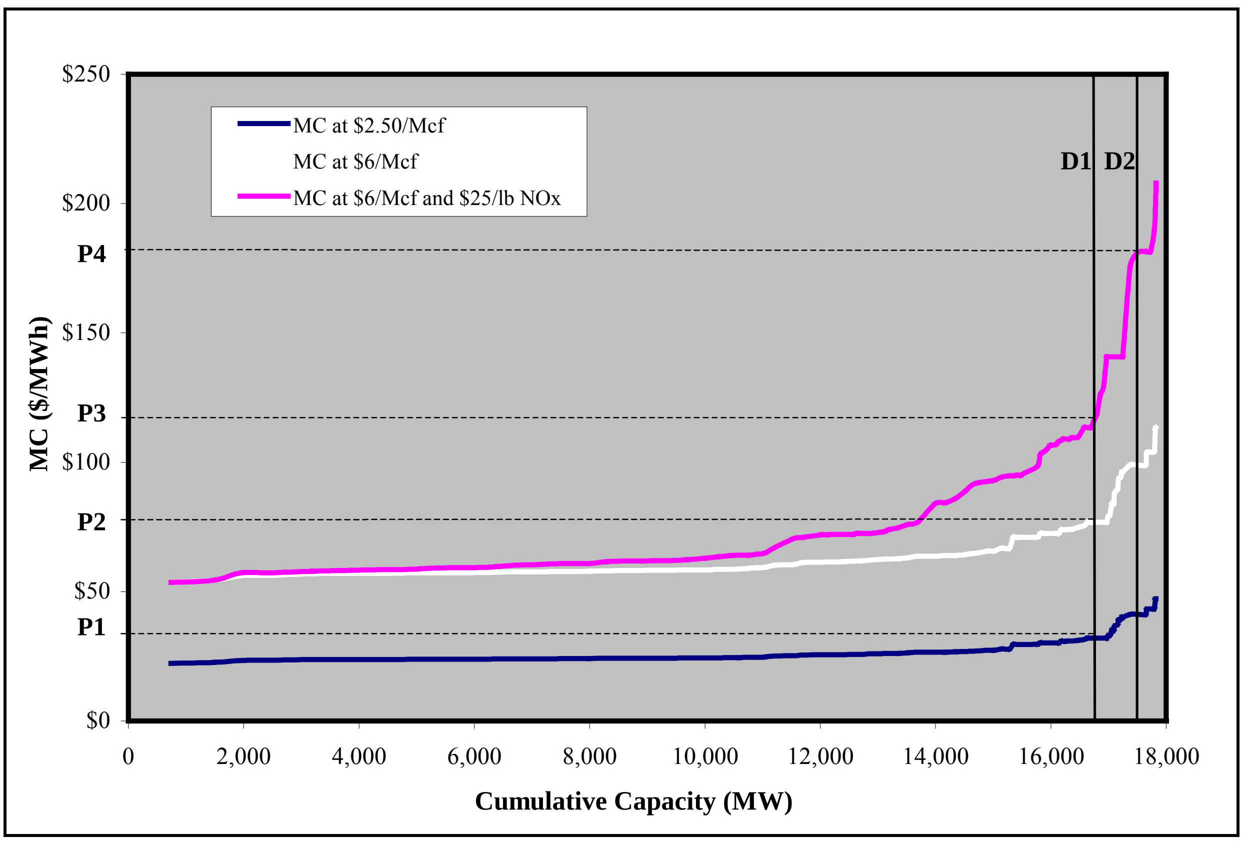
During the Summer months, the marginal supply resource that clears supply and demand is typically a conventional steam or combustion turbine unit fueled by natural gas or oil. Figure 1 depicts the marginal cost curves for this gas-fired generating capacity in CAISO's control area, assuming that the price of gas is either \$2.50/Mcf (as in 1999) or \$6/Mcf (as in late Summer 2000). These marginal cost curves can be thought of as the "top" of the CAISO area's competitive generation supply curve during the Summer

[8] Technically, wholesale prices have not been "deregulated." They are subject to regulation by the Federal Energy Regulatory Commission (FERC) pursuant to the Federal Power Act. The Federal Power Act requires FERC to approve wholesale prices only if they are "just and reasonable." Traditionally, FERC fulfilled its obligations under the Federal Power Act by using various cost benchmarks to cap wholesale prices (Joskow, 1989). During the 1990s FERC began to grant suppliers "market-based pricing authority" if they could demonstrate that they did not have market power (Joskow, 2000). This is the basis for "deregulation" of wholesale market prices in California.

[9] The PX ceased functioning in January 2001(?). During its existence, the PX also operated "hour-ahead" and monthly block forward markets, but they were of little quantitative or financial significance and will not be discussed further here.

months. During Summer hours, a competitive market would clear somewhere along these supply curves. Changes in natural gas prices shift the supply curve up or down and, other things equal, competitive market prices would move up or down along with the changes in gas prices. Changes in demand move the equilibrium competitive price along this supply curve so that competitive prices increase directly with demand. As we shall discuss, tradeable permits for NOx emissions increase and "twist" the marginal cost curve depending on the price of NOx credits and differences in emissions rates across generating units, so that the competitive price for electricity increases directly with NOx permit prices. In addition, at high demand levels, the competitive supply curve is much steeper with a NOx permit trading system than without one. This is the case because the generating units with the highest emissions rates produce as much as 50 times more NOx per unit of electricity output than those with the lowest emissions rates while the difference in marginal fuel costs between the most efficient and least efficient generating unit is only a factor of about two.

Figure 1. Marginal Costs for Gas Units



Until 1998, the roughly 18,000 MW of gas-fired capacity in the CAISO's control area was owned by the three vertically integrated IOUs. Under California's restructuring program, these utilities were required to sell this capacity to independent companies or New Generation Owners (NGOs). As noted above, most of this capacity was ultimately sold to five out-of-state companies with large national unregulated power plant businesses. The nuclear and hydroelectric capacity, and the high-price contracts with QFs, were retained by California's three IOUs. This amounts to about half of the original in-state generating capacity originally owned by or contracted for by these utilities prior to restructuring. The hydroelectric capacity retained by the IOUs has limited energy production capabilities over the course of the year dictated by reservoir storage capacity, water runoff, and water release constraints.

California has historically imported large quantities of electricity from neighboring states. During the 1960s and 1970s long high voltage transmission lines were built from California to the Northwest and the Southwest to facilitate transfers of energy to and from California. California typically imports electricity from the Southwest (primarily nuclear, coal and gas-fired capacity) year round and imports large amounts of electricity from the Northwest (primarily stored hydro) during the Spring and Summer months. During the late Fall and Winter months California historically exported some electricity to the Northwest, primarily during off-peak hours. The generating capacity in the Southwest and the Northwest available to sell electricity to California is primarily controlled by vertically integrated IOUs or Federal Power Marketing agencies. These entities in turn have legal or contractual obligations to supply their local "native loads" and can only sell any excess supplies to California. One of California's investor-owned utilities (Southern California Edison) owns nuclear and coal capacity in the Southwest and has contractual entitlements to some hydroelectricity produced at Hoover Dam. Though the nuclear and coal plants have been put up for sale at auction and winning bidders for some of this capacity have been chosen, this capacity continued to be controlled by Southern California Edison during the period we studied.

Electricity demand in California is highest during the Summer months and lowest in the Spring and Fall months. It is highest during the day and lowest at night and on weekends. The peak demand in the CAISO control area in 1999 was about 43,000 MW. Demand fell to less than 20,000 MW during some off-peak periods. California's restructuring program included a "retail competition" option which permitted all retail consumers to arrange for their power supplies with an unregulated retail electricity service provider (ESP) of their choice. ESPs arrange for power supplies in the wholesale market and deliver it to consumers over one of the utility's distribution networks. The distribution and transmission charges are regulated separately based on cost by the California Public Utilities Commission (CPUC) and FERC respectively. Consumers who do not voluntarily choose an ESP continue to receive "default service" from one of the three IOUs as they always have. About 90% of the retail demand continued to be supplied by the utilities during 2000.

It is particularly important to note that the short run elasticity of demand for electricity in California is close to zero and is almost completely unresponsive to swings in hourly prices since few consumers have hourly recording meters or the communications and control equipment to interact directly with the wholesale market. Moreover, during the time period we study, while wholesale prices were effectively deregulated, retail prices for generation service continued to be regulated based on a pre-determined retail price of roughly \$60/MWh. When this cap was set in 1996, it was expected that wholesale prices would be far below this figure (about \$30/MWh) for several years and that the "head room" between the \$60/MWh retail price and the expected lower wholesale price would allow the utilities to recover quickly the costs of nuclear plants and QF contracts whose total costs were thought to be higher than their competitive market values in the wholesale market ("stranded costs"). As soon as these stranded costs were recovered retail prices for electric energy were then supposed to be deregulated and fall to reflect wholesale market conditions. The year 2000 led to some surprises on this front.

California's restructuring and competition rules required the IOUs to serve all of their default service demand from the PX and ISO spot energy markets.[10] They were also required to bid all of their remaining generation supplies into the PX and ISO spot markets. Independent generation suppliers and non-utility demands were not required to deal through the PX or ISO markets, but could instead enter into bilateral contracts and self-supply ancillary services. Since the utilities retained responsibility for such a large fraction of the demand, most of the wholesale trade in electricity took place either in the PX's day-ahead market or in the ISO's real-time balancing market.

Generators can receive revenues from several sources. They can sell energy to the PX and ISO. They may also enter into forward contracts with entities other than the three California IOUs. Finally, they can earn revenues by supplying "ancillary services" to the ISO. These services are reserves that the ISO can call on to manage imbalances in supply and demand and to deal with congestion. Generators selected to provide ancillary services effectively enter into an option contract with the ISO. They are paid a market-clearing price (day-ahead or hour-ahead) to hold capacity in reserve and available to the ISO. They are then paid for any energy that the ISO calls them to provide, based either on the market clearing price for energy or their bid, whichever is higher.

Our analysis of prices focuses on the hourly day-ahead unconstrained prices observed in the PX during the Summer of 2000. We focus on the PX because it was the venue where the bulk of the energy was traded. Moreover, there appears to have been reasonably efficient arbitrage between the PX market, the bilateral day-ahead market (Joskow, 2000), and the real-time market (Borenstein, Bushnell, Knittel and Wolfram, 2000).[11] We focus on unconstrained prices (that is, pre-congestion management) for

[10] Some forward contracting was permitted by the Fall of 2000 and some limited forward transactions took place in a block forward market run by the PX during 2000 as well.

[11] Joskow and Kahn (2001b) examines whether our supply withholding behavior is affected by using real-time prices rather than day-ahead prices using June as a test case. We also examine a variety of other issues raised by Harvey and Hogan (2001a) in that paper. These considerations do not affect our basic results.

simplicity, though there was relatively little significant transmission congestion during Summer of 2000. We do take congestion into account in our analysis of supplier withholding. It should be noted, however, that our analysis ignores the ancillary services revenues earned by these suppliers and, accordingly, does not cover all of the revenues they receive from the market.[12]

Table 1 displays the average hourly volume-weighted prices for each month from April 1998 through December 2000. The fourth column of the table is a comparable set of forecast prices for year 2000 published by the California Energy Commission in March 2000. The table indicates that PX prices were roughly in line with expectations during 1998 and 1999 and the first four months of 2000. Beginning in May 2000 prices began to rise and then rose to unprecedented levels in June. Prices moderated somewhat in July and then jumped significantly in August before moderating a bit again in September. Prices throughout the Summer months of 2000 were four to five times higher than in 1998 and 1999 and the CEC's projections for 2000. While we have not yet analyzed the post-September prices, it should be clear that prices did not return to "normal" levels and exploded again in December. There are a number of unusual events that affected California's electricity markets after October that make this period difficult to analyze: an order of magnitude increase in gas prices during December, gas shortages, changes in market rules, a large quantity of plant outages, utility credit problems, and other factors. Our analysis focuses on PX market clearing prices during the May through September 2000 period.[13]

It should be noted that the prices in Table 1 do not reflect "fully unregulated" wholesale prices. Until July there was a \$750/MWh cap on prices. This cap was reduced to \$500/MWh during July and then to \$250/MWh in early August. The \$500/MWh and then \$250/MWh cap were binding during many hours in August and September.[14] In addition, as previously noted, Table 1 does not include revenues from sales of ancillary services, which also increased very significantly after May 2000.

[12] Joskow and Kahn (2001b) explore the effects of incorporating ancillary services revenues into the analysis.

[13] See Joskow (2001) for a discussion of the entire period.

[14] Technically, the cap was on prices in the ISO's real-time market. However, since it would have been irrational to pay more than the real-time market price cap in the day-ahead market, this became the effective cap on day-ahead prices in the PX as well. During emergency situations, it was widely known that the ISO would pay more than the price cap for supplies and this probably had the effect of creating more emergencies as generators stopped scheduling supplies day-ahead or hour-ahead in the hope of getting higher prices from the ISO through a last-minute "out of market" sale. The analysis here ignores the price cap and simulates unconstrained competitive benchmark prices. Since we are comparing these simulated prices to actual market prices which reflect the effects of price caps we are likely to underestimate the true potential price gap attributable to market power.

Table 1. California PX Day-Ahead Prices
($/MWh, Weighted Averages 7 x 24)

Month	1998	1999	2000	2000 (CEC)(*)
January	-	21.6	31.8	27.7
February	-	19.6	18.8	24.1
March	-	24.0	29.3	23.3
April	23.3	24.7	27.4	20.0
May	12.5	24.7	50.4	18.5
June	13.3	25.8	132.4	18.8
July	35.6	31.5	115.3	28.0
August	43.4	34.7	175.2	40.9
September	37.0	35.2	119.6	45.3
October	27.3	49.0	103.2	32.2
November	26.5	38.3	179.4	31.6
December	30.0	30.2	385.6	30.7
Average	**30.0**	**30.0**	**115.0**	**28.5**

(*) California Energy Commission Forecasts, 3/13/00.

3. Method for Estimating Competitive Benchmark Prices with Public Data

In this section we estimate competitive wholesale market benchmark prices and compare these benchmark prices to the prices that were actually observed. We simulate an energy market in which all demand clears in a single market, i.e., we do not attempt to simulate the relationship between day-ahead and real-time markets. (We note again that generators earn additional revenues from supplying ancillary services to the ISO. These revenues are especially important for covering the fixed costs of peaking units that supply energy infrequently but serve as operating and replacement reserves much more frequently.) The more the observed price exceeds the competitive benchmark price, the more one can presume that either market power was being exercised or some other source of market imperfection has interfered with the competitive interplay of supply and demand. The competitive price benchmark that we utilize is the short run marginal cost of supplying electricity from the last unit that clears the market in each hour. Comparing realized prices with marginal supply costs in this way is a widely accepted method for measuring the presence of market power, and is especially useful for examining prices in commodity markets with homogeneous products like spot electricity markets.[15] We recognize that modest departures from ideal competitive conditions do not necessarily imply that there is sufficient market power to be of policy concern; many markets that are not subject to price controls are imperfectly competitive. Moreover, any empirical analysis of pricing behavior is subject to some degree of uncertainty. Finally, we recognize that prices may depart from observed marginal cost even in a perfectly competitive market to reflect real capacity constraints and opportunity costs associated with inter-temporal production limits on energy-limited generators such as hydroelectric plants. However, this approach allows us to quantify *how far* realized market prices depart from competitive benchmark prices and provides a useful metric, *along with our analysis of withholding behavior*, that policymakers can utilize to come to a judgment about whether the gap between competitive benchmark prices and actual prices is so large that regulatory interventions are justified.

This approach to measuring market power in wholesale electricity markets was pioneered by Wolfram (1999) in her study of the electricity market operating in England and Wales. The same approach has been applied previously in studies of the California market (Borenstein, Bushnell and Wolak, 2000; Wolak, Nordhaus and Shapiro, 2000; and Hildebrandt, 2000). We will discuss these earlier studies of market power in California's wholesale electricity markets further below, though we note here that these studies relied on confidential data to which we do not have access. Our work extends this approach to incorporate a complementary analysis of supplier behavior.

The only published estimates of the competitive benchmark wholesale energy prices for California have been made by researchers with access to confidential CAISO

[15] Economists frequently use the "Lerner Index" to measure market power. The Lerner Index is calculated by taking the difference between realized prices and marginal supply costs and dividing by the realized prices: $L= (P-MC)/P$. In a perfectly competitive market the Lerner Index is zero and in a pure monopoly it is equal to one. The more the Lerner Index differs from zero, the greater is measured market power. See Carlton and Perloff (1999), pages 92, 264, and 269 and Tirole (1988), pages 66, 70, 80 219-220, and 222.

data. In particular, Borenstein, Bushnell and Wolak (hereafter BBW) and Wolak, Nordhaus and Shapiro (hereafter WNS) adopt a methodology that takes advantage of CAISO data to simulate the competitive wholesale market price for energy in every hour.[16] Hildebrandt (2000) also makes such estimates, using a methodology described in CAISO (2000). We also refer to Hildebrandt's approach, but because the method is described in less detail, we emphasize BBW in what follows. We describe BBW's procedure briefly and then discuss how approximations must be made when the confidential data they rely upon are not available. Because WNS use the same methods as BBW, but they are described in detail only in BBW, all of our discussion of WNS procedures refers to BBW.

We begin by summarizing how BBW estimate the output and competitive benchmark price for the different types of resources that serve demand in California. BBW rely on CAISO settlements data for the hourly output of must-take generation, geothermal and hydro production.[17] The sum of the output from these resources generally exceeds 20,000 MW. CAISO peak loads are typically in the range of 30,000 to 45,000 MW. Imports and California in-state fossil generation make up the difference. Net imports are not used directly by BBW. Instead they adjust observed net imports to reflect competitive responses to price. SCE's share of Mohave, located in Western Arizona, is treated as an internal resource by the CAISO. Consequently, we assume that BBW include its output in their measure of must-take generation. Production from other out-of-state plants owned by in-state utilities, in particular the Palo Verde nuclear plant and the Four Corners plant, apparently is classified as imports. If observed market prices are above the competitive level, then observed imported quantities will be above the level that would be obtained under lower competitive prices. BBW rely upon adjustment bids to characterize the price responsiveness of imports.[18] They then simulate a dispatch of the in-state fossil generation included within the CAISO grid against the remaining demand. To take account of random forced outages, BBW use a Monte Carlo procedure, taking draws from the outage distribution based on public data.

Our procedure differs from BBW because it must be adapted to the limitations of public data, and our goal of making relatively simple, but robust estimates. We describe each major element of our analytical approach below.

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[16] Sheffrin (2000), discussed below, also has an estimate of the "competitive benchmark" price, but there is no discussion of the procedure used to construct it.

[17] Must-take generation consists primarily of nuclear and Qualifying Facilities under PURPA. BBW argue that the behavior of geothermal and hydro owners is competitive during the period they examine and so they use the hourly settlements data on that behavior in their calculation.

[18] Adjustment bids are supply and demand curves representing offers by scheduling coordinators to increase or decrease output at potentially congested interfaces. BBW aggregate these bids over all interfaces on the boundary of the California ISO control area. This information is not publicly available.

Load Slices

We are constrained to analyze months as homogeneous periods because we only have hydro data available on a monthly basis (see below). Within each month, we rely, for simplicity, on 100 load periods. Joskow and Kahn (2001a) relied on 10 load periods. (We have increased the number of load slices to cover 100 load periods in response to arguments that the 10 load periods approach missed the "convexity" in the supply function and underestimated competitive benchmark prices.) We segment the hourly demand in each month into 100 load periods. Within each load period, we look at the mean load in the period and use the intersection of that demand with the supply curve for the month to estimate the mean price for that load point. We add 3% to each demand level reflecting the CAISO's demand for ancillary services capacity.[19]

Hydro

Public data on hydroelectric output is only available on a monthly basis. EIA Form 759 gives output at the unit level. These data allow us to separate units that are dispatched by the CAISO from other California hydro units, but provide no information about how to allocate the energy from the relevant units to different time periods. We have tried assigning this energy to periods within each month using different algorithms. These algorithms assign energy to higher demand periods up to a maximum subject to the constraint that every period receive some minimum amount of hydro energy. Our base case relies on an algorithm which limits the amount of hydro energy in each period to a minimum of 60 percent of the amount that would be assigned to each hour if hydro energy were spread evenly throughout the month and a maximum of 8,500 MW. This is a conservative procedure that may tend to allocate less hydro energy to high demand periods than actually occurs, leading to higher estimates of competitive peak period prices for electricity.

The 8,500 MW hydro maximum is used by the ISO as their estimate of hydro capacity available in their control area (CAISO, 2001, p.9). It represents approximately two thirds of the hydro capacity inside of the ISO.[20] Because of long-term contracts and agreements, such as those between WAPA and many CA municipal utilities, not all hydro capacity is available to meet peak demand. The 8,500 MW figure is approximately the capacity that can be dispatched by SCE and PG&E and hence is likely to be price-responsive.

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[19] In Joskow and Kahn (2001a) we followed Hildebrandt (2000) which includes a 10% adjustment for ancillary services, representing 3% for regulation and 7% for WSCC guidelines on reserves. We have now become convinced by others, including Harvey and Hogan (2001a), that the 10% adjustment is too large. Accordingly, in this paper we use 3%, representing expected demand for regulation energy. BBW also add regulation demand to load, but use actual ISO regulation requirements, which sometimes included other requirements, rather than an expected target such as 3%. Under its "Rational Buyer" protocol, the ISO sometimes substituted purchases of regulation for purchases of other reserves when the price of regulation was favorable.

[20] Based on EIA Form 860, we count just under 12,000 MW of hydro capacity inside of the ISO including all hydro and pump-storage capacity in California besides that owned by LADWP.

Outages and Availability

Forced and planned outages are different phenomena. Planned outages for maintenance are typically scheduled in low demand periods. This has the effect of equalizing reserve margins across months, to the extent possible. This is a common procedure in the industry and in production simulation modeling. During the Summer period there should be no planned maintenance, and we do not include any allowance for it. We use NERC GADS data (NERC, 2000) on historical average forced outage rates by unit type to adjust the marginal cost curve (i.e., shift the supply curve backwards) to reflect "non-strategic" forced outage rates. This procedure is sometimes referred to as "de-rating" the nominal capacity of units to a "firm" capacity level. The forced outage rates for the gas plants are in the 6% to 13% range.[21]

Wind turbine generators present a special problem. The CAISO applies an 80% unavailability factor to account for the random availability of wind power. We adopt this conservative view and convert the 1,876 MW maximum capacity of wind turbine generators into 375 MW of firm capacity.[22]

Our methods for reflecting forced outages differ from those of BBW. BBW use a Monte Carlo simulation of forced outages for in-state fossil generation. BBW argue that maintenance decisions for these units are strategic variables and, therefore, they make no estimate of such outages for in-state fossil generators. By relying on settlements data for must-take resources, BBW are reflecting both maintenance and forced outages for all of this capacity. In contrast, we apply the outage treatment for in-state fossil to must-take resources as well, since we do not have hourly outage information.

Our derating procedure underestimates supply if actual outages were below the historical levels reflected in the outage data we utilized.[23] Of course, one of the rationales for introducing competition into the electric power industry was that market incentives would lead competitive suppliers to *increase* availability, reduce forced outages, and increase effective capacity. Although it is difficult to verify actual outages for many resources, plant-level monthly energy data are available from EIA Form 900. We found that both Diablo Canyon and San Onofre nuclear power plants (which remained in the hands of the incumbent utilities and were subject to complex regulatory transition arrangements) ran at full capacity over the Summer months. Accordingly, we place them in our supply curve at full capacity.

[21] The GADS data define a number of different outage rates. We use the EFOR (equivalent forced outage rate). BBW appear to use the FOF (forced outage factor). The FOF for gas plants range between 3% and 4%.

[22] See CAISO (2001), pp. 13-15.

[23] Both BBW and Hildebrandt use actual hourly output for all must-take resources. These data are not available publicly. Since must-take resources are likely to be operated in a price-taking manner, it is appropriate to use actual production in their case. Strategic generators should not be treated in this fashion.

Imports

Our measure of imports differs slightly from BBW. As discussed above, we assume that BBW include production from SCE's share of Mohave in their measure of in-state must-take generation. We include Mohave's generation in imports because its output is included in the line flows that we aggregate to construct our measure of net imports.

Otherwise we adopt the BBW philosophy with regard to adjusting imports. They argue that high observed prices in California draw in more imports than would occur under lower competitive prices, other things equal. BBW use confidential data on adjustment bids to characterize this elasticity. We have assumed an elasticity of 0.33. This elasticity is loosely based on BBW's claim that imports would be 5.3 percent lower (p. 30) and prices approximately 15.5 percent lower (p. 33) under marginal cost pricing. Given the imprecision of their elasticity estimates,[24] an elasticity of 0.33 is well within the range of what they find. We then use data on observed net imports, and PX prices to impute net imports under marginal cost pricing. In other words, for each period and for every price level *c*, we calculate the amount of infra-marginal net imports as follows:

$$netimp(c) = \left(\frac{c}{p_{px}} \right)^{\eta} * netimp(p_{px})$$

where η is the elasticity of net imports, p_{px} is the realized PX price, and $netimp(p_{px})$ is the realized level of net imports at the realized PX price. Our benchmark price is then the *c* at which the sum of estimated net imports and infra-marginal in-state generation, including must-take generation, clears the market.

We rely upon imports to clear the market when in-state fossil supply is exhausted. Because this will occasionally require more net imports than what was actually observed, our procedure will raise their price substantially when this is required. These prices will be higher than the ISO price caps in place during the Summer. We interpret these cases as corresponding to the ISO's purchase of Out of Market (OOM) energy.

In-State Fossil Generation

Natural gas costs for weekdays at the Southern California burnertip and at Malin were provided to us by Southern California Edison, from trade publications. We add transport costs to the Malin prices to bring the costs to the burnertip in Northern California. Because we are constrained to a monthly level of analysis, we use monthly averages of these prices. The monthly gas price values used are given in Section 4, where we present results.

We rely upon the Henwood Energy Services Incorporated (HESI) commercially available database for the WSCC to characterize heat rates, and variable O&M costs for in-state fossil generators. The heat rate data are consistent with those found in Klein

[24] BBW's estimate of 5.3 percent has a standard deviation of 8.1 percent.

(1998). There are many definitions of unit capacity, which result in quantitative differences that typically are small.[25] Accordingly, we adopt for this analysis the capacities posted on the ISO website.[26]

RECLAIM NOx RTC Prices

One factor that can affect competitive market prices for electricity which neither BBW nor the CAISO addresses involves the impact of the air emissions regulatory framework in California. California has extremely stringent air quality regulations. One pollutant of particular concern is nitrogen oxide (NOx). As explained above, regulation of emissions in the Los Angeles area is controlled by the SCAQMD, which operates the RECLAIM Trading Credit (RTC) emissions permit trading program for NOx emissions from electric generating units and other stationary sources. Under this program NOx emissions are regularly reported during pre-established cycle periods. The owners of a source of NOx emissions must reconcile NOx RTC allowances with reported emissions within 60 days of the end of the reporting cycle.[27] The RTC program resembles the SO2 permit trading regime authorized under the 1990 Clean Air Act Amendments.[28]

We would expect competitive generation suppliers to include the prices of RTC NOx credits in their bids even if these credits had been previously acquired at much lower prices (or for free). This is the case because these emissions credits could be sold to other affected sources at their market value and thus represent a legitimate competitive market opportunity cost.[29] RTC allowances had been selling at very low prices ($1-2/pound) through the early part of 2000. Since most generation in the SCAQMD area emits 1 lb/MWh of NOx or less, emissions costs internalized into electricity prices would be $1-2/MWh at most during this period. Starting in Spring 2000, however, RTC prices began to increase substantially.[30] By June they were nearly $10/pound. This would add $10/MWh to MCP most of the time, and much more when gas turbines with much higher emissions rates, e.g., some turbines emit in excess of 6 lb/MWh, are producing electricity. NOx RTC prices continued to climb throughout the Summer, rising to around $35/pound by late August. At these levels, NOx RTC requirements significantly affect

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[25] Harvey and Hogan (2001a) took issue with the definition used in Joskow and Kahn (2001a). Joskow and Kahn (2001b) use different sources.

[26] See http://www1.caiso.com/docs/2001/04/02/2001040211441714244.xls

[27] NOx RTC allowances have expiration dates that correspond to the end of each cycle period.

[28] The SO2 emissions trading program is described in detail by Ellerman *et al* (2000).

[29] Obviously, generators which acquired these RTC NOx credits at much lower prices will earn very significant profits as a consequence of the run-up in NOx credit prices and its impact on wholesale electricity prices. Thus, the impact of changes in NOx credit prices on electricity prices in a competitive wholesale market is far larger than it would have been under traditional cost-of-service regulation where consumers would have captured any infra-marginal "rents" associated with changes in NOx credit prices.

[30] We have not analyzed why NOx RTC credit prices increased so much during the summer of 2000 or whether the observed price increases are consistent with competitive behavior in the RTC credit market. A careful analysis of behavior and performance of the RTC credit market would also be a worthwhile undertaking.

price during all hours for which fossil plants in the SCAQMD clear the market, but especially during peak periods when gas turbines are on the margin. Therefore, we decided to add the effects of NOx RTC prices to our estimates.

For most units in SCAQMD that were formerly owned by SCE, we rely on estimates of NOx emissions rates provided to us by SCE based on publicly available data and regulatory filings. For other units, we rely on NOx emissions rates from the HESI databases.

4. Results

Table 2 below presents our estimates of competitive benchmark prices for May through September 2000. We report a range of prices, reflecting alternative assumptions about NOx RTC prices. Table 2 also displays the actual average day-ahead PX prices during these months of year 2000 for comparison purposes. The data on NOx RTC prices are difficult to interpret for a variety of reasons. There is general agreement that NOx RTC prices were increasing between May and September. Finding an appropriate price for each month requires that we interpret the data from SCAQMD carefully. We give a full discussion of the choices we have made in the Appendix. Table 2 indicates in bold the benchmark wholesale market price associated with our choice of the most appropriate NOx RTC price for each month.

Table 2. Competitive Counterfactual at Different RTC Costs (2000)

Month	Average PX Price ($/MWh)	Competitive Benchmark Price ($/MWh)					Average Gas Price ($/MMBtu)	
		Assumed NOx Price						
		$0/lb	$10/lb	$20/lb	$30/lb	$35/lb	North	South
May	47.23	**55.11**	58.56	61.79	64.66	64.63	3.77	4.11
June	120.20	64.84	**67.23**	70.14	73.38	74.99	4.59	4.99
July	105.72	58.62	60.91	**63.25**	65.60	66.72	4.35	4.97
August	166.24	86.96	92.02	96.97	102.40	**105.15**	4.84	5.69
September	114.87	74.08	78.34	83.07	86.88	**88.96**	5.88	6.64

It is clear from Table 2 that there is a significant gap between the competitive benchmark prices that we estimate and actual market prices in June, July, August and September 2000. We want to emphasize that this gap between competitive benchmark prices and actual market prices takes into account the effects of gas prices, load levels, import levels, and NOx credit prices; the “market fundamentals” that have often been identified as contributing to higher prices in Summer 2000 than in Summer 1999. It is also interesting to note that if NOx credit prices had remained at 1999 levels, competitive benchmark prices would have been reduced significantly, especially in August. We believe that the estimated price gap is large enough to provide compelling evidence that market power or other market imperfections lead to a significant increase in prices above competitive levels during Summer 2000.

Our estimates of competitive benchmark prices are very similar to those obtained in other studies using similar techniques and confidential data to which we do not have access. BBW does not include the cost of RTC allowances in their estimates. Given the very low level of RTC prices until the Spring of 2000, these costs would not significantly impact the estimates made in BBW, since these only extend through September 1999. Hildebrandt’s estimates of the May-September competitive prices are similar to our estimates in the zero RTC price case. For May, June and July our estimates are within $1/MWh of his. For August and September our estimate is $4-8/MWh higher.

Import Sensitivity

One use of the framework that we have applied to develop competitive benchmark prices is to examine hypotheses about the effects of key variables on competitive market prices. Here we examine the effect on wholesale prices of reductions in net imports between 1999 and 2000. Many commentators have remarked on the significant decline in net imports between Summer 1999 and Summer 2000. Table 3 shows the mean difference in actual monthly net imports from year to year. It also compares the estimated benchmark price before considering effects of RTC credit prices (i.e., based on the zero RTC credit price column in Table 2) with our estimate of what the competitive benchmark price would have been if the 1999 level of imports had occurred. It is clear that prices are higher in Summer 2000 as a result of lower net imports, but if NOx emissions were not an issue, the impact of reduced imports alone accounts for a relatively small fraction of the actual increase in wholesale prices from Summer 1999 to Summer 2000. As NOx RTC prices rise toward the end of the Summer, the reduced level of imports becomes a much more important factor in explaining wholesale price increases. This is the case because as imports fall, in-state generating units with relatively high emissions rates run more often to balance supply and demand.

Table 3. Net Import Sensitivity

		June	July	August	September
1999 actual average hourly net imports (MWh)		5,871	6,633	6,539	7,070
2000 actual average hourly net imports (MWh)		4,262	3,621	3,162	4,386
MCP with 1999 net imports ($)	NOx $0/lb	60.33	47.10	58.08	64.89
MCP with 2000 net imports ($)		64.84	58.62	86.96	74.08
MCP with 1999 net imports ($)	NOx $10/lb	62.22	48.47	62.18	67.30
MCP with 2000 net imports ($)		67.23	60.91	92.02	78.34
MCP with 1999 net imports ($)	NOx $20/lb	65.08	49.56	65.02	69.17
MCP with 2000 net imports ($)		70.14	63.25	96.97	83.07
MCP with 1999 net imports ($)	NOx $30/lb	68.05	50.46	68.19	70.75
MCP with 2000 net imports ($)		73.38	65.60	102.40	86.88
MCP with 1999 net imports ($)	NOx $35/lb	68.52	50.95	68.18	71.35
MCP with 2000 net imports ($)		74.99	66.72	105.15	88.96

5. Withholding and Unilateral Market Power: The Economic Logic

The previous analyses shows that "market fundamentals" cannot fully account for the high levels of observed prices in the Summer of 2000. Even after accounting for lower levels of imports and very high NOx RTC prices, we still observe a large deviation of wholesale market prices from the competitive benchmark price, i.e., marginal costs of supplying additional electricity at the associated market clearing quantities. However, while we observe large price/marginal cost margins during the Summer of 2000 which we believe are inconsistent with competitive markets, our analysis so far does not measure behavior that is likely to be the cause of these high prices. It has been conjectured, for example, that the high observed prices simply reflect scarcity rents that arise when demand is high, capacity constraints are binding, and competitive market prices must rise to clear the market (CaPX, 2000). In the next two sections we investigate the hypothesis that withholding behavior by generators in California is one cause of the large measured gap between prices and marginal costs. It is clear from first principles that supply withholding could be the source of high prices. Whether this is, in fact, the case is an empirical question.

We begin by presenting a simple example to demonstrate the unilateral profit maximization logic behind capacity withdrawal and show that rational capacity withholding does not require collusion among suppliers. We consider the unilateral case, i.e., only one portfolio player adopts this strategy and all other generators behave competitively and bid at prices equal to their marginal cost. We can characterize the profit effects of capacity withdrawal simply as the sum of two effects. These are (1) the increased profits on the capacity offered after withdrawal due to the ability to raise price, and (2) the lost profits of capacity withdrawn (see Wolfram, 1998). The profit changes must-take account of the cost reduction due to not producing on the withdrawn capacity. We can express these effects as follows:

$$\Delta \text{ Profit} = \Delta \textit{ Price * Remaining Quantity - } \Delta \textit{ Capacity * Competitive Price + } \Delta \textit{ Operating Cost}$$

This expression is derived formally in the Appendix.

As is apparent from the formula, whether withdrawing capacity is in the self-interest of a portfolio generator will depend critically upon the slope of the supply curve. It must be steep enough to result in MCPs sufficiently high so that the increase in profit on generation still tendered to the market more than offsets the profits lost on the capacity withdrawn. We construct some examples based on our benchmark estimate of competitive supply conditions that prevailed in June 2000. These estimates come from our June simulations (with NOx effects). We examine one case, at higher loads, where a load increase or capacity withdrawal of 1,500 MW results in a price increase of about $36 per MWh. Our second case, at lower loads, produces only a $3 price increase for the same 1,500 MW withdrawal.

Table 4 displays the profitability effects of capacity withholding for the two examples.[31] In both cases, we make three assumptions: (1) the portfolio generator with 3,000 MW of capacity produces only half that amount, (2) the competitive MCP is \$60/MWh,[32] and (3) the generator's marginal cost is \$55/MWh. In the first case, where capacity withdrawal raises price significantly, the revenue gain is large. In the second case, the impact of withholding capacity on price is relatively small because supply is much more elastic over the relevant range of output. Withholding is unprofitable since the increase in price on the tendered generation does not offset the lost profits on generation withheld. The details of these results are shown in the following table.

Table 4. Unilateral Market Power Examples

Case	Revenue Loss	Revenue Gain	Cost Savings	Δ Profit
Δ Case 1 High Price Increase	90,000	54,000	78,750	42,750
Δ Case 2 Low Price Increase	90,000	4,500	82,500	-3,000

These stylized examples are constructed to make it difficult to find unilateral market power.[33] They rely on the assumption that only one supplier withholds capacity, while all of the other suppliers behave competitively. In the California electricity market during the Summer of 2000, it appears that more than one portfolio player was implementing a withholding strategy. We illustrate this claim empirically in the next

[31] This example differs slightly from a similar calculation in Joskow and Kahn (2001a). The changes reflect re-estimation of the supply curve.

[32] As Appendix B illustrates, the slopes of the supply curve used in the examples lie just above and below the reference price of \$60/MWh.

[33] Harvey and Hogan (2001b) explore this example at some length. Their discussion seems to confuse the stylized example representing competitive conditions with observed behavior in the real market. In the real market, the price changes associated with load changes were much higher than those used in the simple competitive case. This increases the incentive to withhold substantially. Moreover, we want to emphasize that the example was structured to make it difficult to find unilateral market power to be profitable since it assumes that all other suppliers are price takers and behave as a competitive fringe. If we had made the more conventional assumption of non-cooperative oligopoly models (e.g., Cournot or Supply Function Equilibrium models) that multiple suppliers could act strategically, the incentive of a single supplier to withhold would be even greater. Further, since organized wholesale electricity markets involve repeated interactions between suppliers in the context of good public information about supplier costs, demand, and market prices, one might expect to find more collusive outcomes by applying a repeated game framework rather than static non-cooperative oligopoly theory. The bottom line is that there are very good theoretical reasons to believe that suppliers have market power when demand is high and supply is relatively inelastic given the other characteristics of electricity (e.g., non-storability). If there is a puzzle here, it is why prices were not even higher than those observed. A partial answer is that, but for the price caps in effect, actual prices would in fact have been much higher than those we observe.

section. If multiple suppliers are behaving strategically, the effects of withholding on wholesale market prices could be much larger than suggested by these simple examples.

6. Empirical Analysis of Withholding

Now we turn to the analysis of physical supply and withholding behavior. We use plant and unit level output data from EPA, the ISO's real-time dispatch, and the WSCC to examine the physical behavior of the price setting firms to determine whether there was really "scarcity, " that is, that demand was so high that competitive prices above marginal cost were necessary to clear the market, or whether generators withheld supplies from the market when it would have been profitable for a generator without market power to supply more.

We restrict our analysis to a set of high-priced hours when it should have been economical for virtually all of the fossil generators to supply, absent market power. In particular, we look at hours when the real-time price[34] was greater than 17,000 Btu/kWh times the delivered gas price plus 1 lb NOx/MWh times the monthly RTC price. The heat rate threshold covers virtually all steam and most peaking units. The NOx emission rate covers almost all steam units. Units with higher costs should be reserved to provide ancillary services. Table 5 below shows the average price and number of hours per month that meet this criterion.

Table 5. Monthly Cut-Off Prices and Number of High-Price Hours

Month	Monthly Cut-Off Averages ($/MWh)		Number of High-Price Hours	
	SP15	NP15	All Hours	Hours without South to North Congestion
June	95	89	104	96
July	105	95	124	114
August	132	118	271	241
September	148	139	82	66

We compare observed levels of production by units likely to be setting prices, with their maximum generating capacities during those hours.[35] NP15 generation is analyzed separately from SP15. There is a substantial "output gap" between observed and maximum possible levels of generation in both zones. Three factors may explain this gap: (1) capacity may be covering the CAISO's ancillary services requirements, (2) capacity may be out of service due to forced outages, and (3) interzonal transmission constraints (South to North) may limit economic dispatch of SP15 plants. Therefore, we test whether the gap can be explained by these three factors. If the gap cannot be

[34] We focus on the real-time price, as opposed to our first analysis (2001a) that used day-ahead prices. Harvey and Hogan (2001a) correctly observe that the real-time price is a better indicator for production data since it reflects all output decisions by suppliers. As we observed earlier, however, there is a close correlation between these prices.

[35] These calculations correct for the Daylight Savings Time issue identified in Harvey and Hogan (2001c).

explained, we conclude that it is indicative of generator withholding resulting either from high bids that do not clear the day-ahead or real-time energy markets or direct withholding of capacity from these markets.

- The ancillary services tests have two elements: (1) we compare the zonal CAISO ancillary services requirement in the selected hours against the output gap, and (2) we consider whether the CAISO dispatched reserves during our sample hours. If reserves were dispatched, they will appear as production in our data and would, therefore, not explain any output gap.

- The forced outage test is necessarily limited in its applicability. We apply three outage tests to the data to ascertain whether forced outages might explain output gaps.

- The congestion test requires that we identify congestion during our sample hours. Production levels in hours without a constraint should not be affected by transmission issues.

We rely on three data sources for this analysis. Each has hourly production data, but the sources differ by the units covered. EPA's Continuous Emissions Monitoring System (CEMS) database tracks hourly production and emissions of certain pollutants that are regulated under the Clean Air Act. CEMS data are available on the EPA's website. CEMS data do not include gas turbines and some small thermal units. Table 6 below lists the largest units that are omitted from the CEMS database, their ownership, capacity and NOx emission rates. About 1,300 MW of gas capacity is excluded from the EPA data. We address units excluded from CEMS in two ways. For most peaking units, we rely on the ISO BEEP stack dispatch.[36] The BEEP data record the energy dispatched from units in real time, but do not include any energy that may have been scheduled before real time. Because we are using BEEP to characterize the output of GTs and GTs generally run fully loaded, when we observe output for a unit in a given hour in BEEP we assume that the unit operated at full load for that hour. The third source gives data at the plant level, not the unit level. These data are from the WSCC's Extra High Voltage (EHV) database. The EHV data, which are available to all WSCC members, were provided to us by SCE. We rely on this data only for the Long Beach units. These are rather inefficient combined cycle units, with heat rates of approximately 10,500 Btu/kWh, which could nonetheless be expected to produce energy during high-price hours.

[36] BEEP is an acronym for Balancing Energy and Ex-Post Pricing. This software records the instructions given by the ISO to units that it dispatches in real time. BEEP stack dispatch data is available on the ISO website.

Table 6. Units Excluded from CEMS Database

Unit	Owner	June Capacity (MW)	NOx (lbs/MWh)
Long Beach 8	Dynegy	276	1.2
Long Beach 9	Dynegy	276	1.2
Highgrove 1-4 (*)	Thermo Ecotek	154	1.2-2.4
Etiwanda GT	Reliant	141	5.4
Alamitos GT	AES	134	6.5
Huntington Beach GT	AES	133	5.7
Elwood GT	Reliant	48	5.4
Mandalay GT	Reliant	132	5.7

(*) While Highgrove reports emissions data as part of the EPA program, these plants did not operate in the relevant time period.
NOx are calculated from publicly-available data.

Analysis of June

We begin by focusing in detail on the month of June. Our analysis attempts to discover if there is an unexplained gap between generators' capacity and observed production. An otherwise unexplained gap would tend to support our hypothesis that production was withheld by generators in an attempt to drive up price during these periods. June is a particularly interesting month in light of criticisms made by Hogan and Harvey (2000a) and others regarding "natural" plant outages and "reservoir effects." Generating units in California typically come back into service from their annual maintenance outages during May and early June and should be ready to operate reliably through the peak Summer months. Accordingly, we would expect generating units to exhibit low forced outage rates during June even if they are run hard during that month. It is also widely accepted, we believe, that the subsequent run-up in natural gas prices, the large increase in demand, and the large increase in NOx credit prices were not anticipated in June 2000 and could not have been factored into competitive supplier behavior during that month. Accordingly, a finding that there was significant withholding of generating capacity during June 2000 is especially strong evidence supporting the exercise of market power as its source.

Logically, congestion on the transmission system could help to explain any output gaps we might identify. We therefore have examined data on interzonal transmission levels and congestion to determine the extent of transmission congestion. Since it appears that withholding was most likely in the SP15 zone, we have reviewed the possible impacts of South to North congestion on our findings. Table 5 shows that while interzonal transmission constraints do occur occasionally, they are typically limited to about ten percent of the hours with real-time prices greater than our threshold prices. In the interest of simplification, we have omitted such hours from further analysis.

We begin by computing the aggregate output gap for all generators for June hours when the real-time price is above our threshold, which averages \$95/MWh in SP15 or \$89/MWh in NP15; there are 96 hours that meet this criterion and where there is no real-time South to North congestion. In each of the 96 hours when the price is above these thresholds, we observe the hourly output of generators owned by Duke, Southern, AES, Dynegy and Reliant. We expect to find that production in these hours will be at maximum levels. Next, we sum up the hourly output for each firm in NP15 and in SP15 separately. We compare the June production of each generator over each of the 96 hours to our estimate of their capacity. We define the output gap for each firm to be the mean difference between total capacity and the observed output in each of the 96 uncongested high-priced hours. It is important to note that the dispatch of these generators may be controlled by contractual arrangements with third parties other than the owners of the generating plants. It has been widely reported that this is the case for the AES units, which operate under a tolling agreement with Williams, but we do not know whether or how much control has been ceded to marketers through contracts otherwise. Accordingly, we use the owners simply to identify the generating plants examined and any apparent withholding observed.

Next, we want to see how much of the gap can be explained by the CAISO's reservation and use of capacity for Ancillary Services (we include Up Regulation, Spin, Non-Spin and Replacement Reserves).[37] Public data on CAISO demands for Ancillary Services (AS) are available by zone. We compare the output gap by zone to AS capacity by zone for each hour. We then check the BEEP data to determine what fraction of reserves were dispatched.[38]. Table 7 below summarizes our results.

[37] We exclude Down Regulation, because that does not require that capacity be held in reserve.

[38] The BEEP stack is the ISO's real-time supply curve. It consists of both bids for imbalance energy and the energy portions of bids to provide ancillary services. The BEEP data that we use to measure the output of GTs also indicate whether a unit was dispatched because an imbalance energy bid was called or because an energy bid associated with a specific ancillary service was called. So, the BEEP data can be aggregated to calculate a measure of dispatched ancillary services.

Table 7. Mean Level of the Output Gap: June 2000

		Mean Values (MWh)			
Zone	Owner	Output	Capacity	Gap	Undispatched AS
NP15	Duke	1,469	1,485	16	
	Mirant	2,063	2,629	565	
	NP15 Total	**3,532**	**4,114**	**581**	**1,222**
SF	Mirant	206	369	163	
	SF Total	**206**	**369**	**163**	**24**
SP15	AES/Williams	2,735	3,967	1,232	
	Duke	675	717	42	
	Dynegy	1,492	2,834	1,342	
	Reliant	2,492	3,790	1,298	
	SP15 Total	**7,394**	**11,308**	**3,913**	**1,326**
ZP26	Duke	990	1,021	31	
	ZP26 Total	**990**	**1,021**	**31**	**31**

For SP15, the mean of the output gap is 3,913 MW compared to 1,326 MW for the mean of the undispatched AS demands in the zone. This leaves an average unexplained mean output gap of nearly 2,600 MW during the 96 hours, making the extremely conservative assumption that all of AS capacity requirements were covered by these units. It is important to recognize that withholding 2,700 MW from the market during high demand conditions can have a very large effect on market prices. Referring back to Figure 1, it can be seen that a modest 1,000 MW increase in demand or reduction in supply can increase marginal supply costs by over 50% at relatively high demand levels. Based on these results, it looks as if a significant amount of capacity is being withdrawn on average during these high-price periods in SP15. Accordingly, the gap between prices and marginal costs cannot be explained by scarcity. The results for NP15 are different. Here the mean of the output gap is 581 MW, which is less than the mean undispatched AS capacity, 1,222 MW. Therefore, we cannot conclude definitely that there was capacity withholding in NP15.

It is important to point out, however, that this assessment is quite crude and supplies an upper bound on AS capacity requirements that might explain the output gap. This is due to two factors: (1) it neglects the possibility that hydro capacity or imports are supplying some of the AS demand, and (2) ramp rate restrictions might have made it physically impossible for the plants to supply the full AS requirement. While we have accounted for the effects of dispatching reserves on our analysis, we are unable to test the effects of alternative suppliers of AS services or those of ramp rate restrictions because of data limitations. Obviously, to the extent that some of the AS demand is being satisfied by hydroelectric capacity and out-of-state resources, as is likely to be the case, the gap would be larger by an equivalent amount.

It is interesting to note that there is no evidence that Duke was withholding output in either SP15 or NP15. Duke Energy, which appears to have been fully contracted in forward markets for 90% of its potential output, behaved much differently from Reliant, Dynegy, Mirant, and AES/Williams. Duke's production in SP15 was proportionally higher than that of these other firms. It reports much lower forced outage rates than what the other firms appear to claim. We believe that the outage rates and production levels reflect economic incentives. If generators are not contracted, their incentive is to withhold capacity and raise price. Accordingly, Duke had no incentive to withhold output to drive up spot market prices, and this lack of incentives appears to be reflected in its behavior.[39]

Extension to July, August and September

Table 8 extends this analysis to the months of July, August and September for the SP15 zone. The pattern of results for NP15 is not materially different in these months than in June, so we drop further discussion of NP15 since nothing can be concluded on the basis of publicly available data.

[39] Harvey and Hogan (2001c) argue that AES was "the company with the highest level of forward sales" and it experienced "unusually high forced outage rates during 2000" (p.77). They are referring to the tolling agreement between AES and Williams. This is not the type of contractual arrangement that mitigates incentives to withhold output to raise prices. This tolling agreement was essentially a contract to "rent" AES' generation capacity to Williams, not a commitment by AES to supply specific production quantities at a fixed price. Under this kind of agreement Williams, not AES, was free to determine how much energy was supplied by these units and could profit if market prices increased during the summer months. As such, Williams had an incentive to withhold, consistent with the settlement that they entered into with FERC involving alleged withholding in April and May 2000 (FERC, 2001).

Table 8. SP15 Mean Output Gaps

Month	# of High Price Hours	Owner	Mean Values (MWh)				Dispatched Ancillary Services (MWh)			
			Output	Capacity	Gap	AS Total	Replacement	Spin	Non-Spin	Total
June	96	AES/Williams	2,735	3,967	1,232					
		Duke	675	717	42					
		Dynegy	1,492	2,834	1,342					
		Reliant	2,492	3,790	1,298	1,756	330	30	69	430
		Total	**7,394**	**11,308**	**3,913**	**1,326**				
July	114	AES/Williams	2,757	3,967	1,210					
		Duke	635	717	82					
		Dynegy	1,811	2,765	954					
		Reliant	2,872	3,790	918	1,169	100	23	42	165
		Total	**8,074**	**11,238**	**3,164**	**1,004**				
August	241	AES/Williams	2,781	3,967	1,186					
		Duke	622	717	95					
		Dynegy	2,043	2,827	784					
		Reliant	3,076	3,790	714	1,532	183	101	79	363
		Total	**8,521**	**11,301**	**2,779**	**1,168**				
September (*)	66	AES/Williams	2,244	3,967	1,723					
		Duke	560	717	157					
		Dynegy	1,894	2,815	921					
		Reliant	3,072	3,790	718	1,135	130	38	39	207
		Total	**7,770**	**11,289**	**3,519**	**928**				

(*) Analysis for September includes days 1 through 20. The EHV data from which the Long Beach data are sourced end at September 20.

Table 8 shows somewhat smaller output gaps in July, August and September. Net of dispatched AS, the unexplained gap for July is about 2,200 MW. In August it drops to about 1,600 MW. In September it rises again to about 2,600 MW. We can express the unexplained gaps as some kind of "outage rate," i.e., normalize them to total capacity. This calculation results in an average outage rate of between 15% (August) and 24% (June). Such rates are very high in comparison to historical average values for similar plants. The data used in our benchmark price analysis, for example, averages 7.5% and Duke's units appear to have achieved similarly low outage rates consistent with the historical experience for these generating units.

Thus far our calculations make no attempt to assess whether the output gap can be explained by unscheduled outages.[40] We examine this question next. Evaluating the

[40] Whether an outage is "scheduled" does not mean that it is not the result of a strategic decision to withhold output to drive up prices. The discussion of strategic behavior in electricity markets has distinguished between "physical withholding" and "economic withholding." Economically they are equivalent. When a firm seeks to affect price by simply not making some capacity available to the market it is engaged in "physical withholding." When a firm decides instead to make the capacity available to the market at a supra-competitive price, knowing that some of the capacity offered will not be selected in the associated auction process, it is engaged in "economic withholding." A supplier that chooses not to make

effects of unscheduled (forced) outages is not completely straight-forward, because of the discretionary element in outages. Therefore we apply three different tests for forced outages. Test 1 measures the capacity of a generation portfolio by looking only at units that were producing any output in the hour in question. This is the strictest definition of a "no outage condition." Test 2 measures the capacity of a generation portfolio by looking only at units that were producing any output in the day in question. Finally Test 3 measures the capacity of a generation portfolio by looking only at units that were producing any output in the day in question or the day before. Another way of describing Test 3 is that an outage is real only if it occurred both the day before the day of our scarcity hours as well as the day of such an event.

capacity available to the market will generally declare the capacity to be "unavailable." This decision may be made well in advance of actual operations ("scheduled outage") or closer actual operations ("unscheduled outage"). Precisely how a supplier chooses to withhold, and for what reasons, is not verifiable and under the CAISO rules there are no penalties against suppliers for being "unavailable" due to either scheduled or unscheduled outages. Nevertheless, we believe that unscheduled outages are even more compelling indications of strategic behavior than are scheduled outages.

Table 9. SP15 Mean Output Gaps by Outage Test

		Test 1			Test 2			Test 3			
Month	Owner	Output	Capacity	Gap	Output	Capacity	Gap	Output	Capacity	Gap	Undispatched AS
June	AES/Williams	2,735	3,030	296	2,735	3,299	565	2,735	3,390	656	
	Duke	675	693	18	675	711	36	675	712	37	
	Dynegy	1,492	2,183	691	1,492	2,386	895	1,492	2,505	1,013	
	Reliant	2,492	3,258	766	2,492	3,511	1,019	2,492	3,592	1,100	
	Total	**7,394**	**9,164**	**1,770**	**7,394**	**9,908**	**2,514**	**7,394**	**10,200**	**2,806**	**1,326**
July	AES/Williams	2,757	3,016	259	2,757	3,249	492	2,757	3,312	556	
	Duke	635	690	56	635	699	64	635	716	82	
	Dynegy	1,811	2,404	593	1,811	2,557	746	1,811	2,665	854	
	Reliant	2,872	3,272	400	2,872	3,395	523	2,872	3,518	646	
	Total	**8,074**	**9,383**	**1,308**	**8,074**	**9,900**	**1,825**	**8,074**	**10,212**	**2,137**	**1,004**
August	AES/Williams	2,781	2,919	139	2,781	2,999	218	2,781	3,102	321	
	Duke	622	701	79	622	717	95	622	717	95	
	Dynegy	2,043	2,608	565	2,043	2,760	717	2,043	2,811	768	
	Reliant	3,076	3,410	334	3,076	3,565	489	3,076	3,633	557	
	Total	**8,521**	**9,639**	**1,118**	**8,521**	**10,040**	**1,519**	**8,521**	**10,263**	**1,742**	**1,168**
September (*)	AES/Williams	2,244	2,425	181	2,244	2,522	278	2,244	2,640	396	
	Duke	560	688	129	560	699	139	560	703	143	
	Dynegy	1,894	2,479	585	1,894	2,619	725	1,894	2,649	755	
	Reliant	3,072	3,513	441	3,072	3,664	592	3,072	3,695	624	
	Total	**7,770**	**9,106**	**1,336**	**7,770**	**9,504**	**1,734**	**7,770**	**9,687**	**1,917**	**928**

(*) Analysis for September includes days 1 through 20. The EHV data from which the Long Beach data are sourced end at September 20.

Test 1 can be thought of as measuring either the withholding of a unit that could produce more in the given hour, or the occurrence of a "partial outage" in that hour. Table 9 shows that about 1,100 to 1,800 MW was not running during the high-price hours in June-September. Undispatched AS could explain some of this amount. Tests 2 and 3 employ different measures of capacity that might have run during the high-priced hours. The intuition here is that often units that might be experiencing some operating problems can be kept on line by operators who are strongly motivated to produce. Alternatively, if there is an economic incentive to withhold, then operators might turn them off. In such cases, "conservative" operation is also profit-maximizing.

The data in Table 9 are unadjusted for the effect of price caps on the economics of plants in SCAQMD with high NOx emission rates. Three of the gas turbines listed in Table 6 are in SCAQMD (Alamitos, Etiwanda and Huntington Beach). With emission rates greater than 4.5 lbs/MWh, these units would have RTC costs greater than $157/MWh in August and September when RTC prices were at $35/lb. The fuel costs of the gas turbines would be at or above $100/MWh during this period as well. When the price cap was lowered to $250/MWh on August 7, these units had marginal costs above the cap. Therefore their capacity, about 400 MW total, should perhaps be excluded from the output gap estimates in Table 9. There may also be a related issue for units with NOx emission rates that are in the 2 lb/MWh range. At $35/lb, these units would have $70/MWh marginal costs for RTC credits. At the gas prices prevailing in August and September, some of these units might have marginal costs above the cut-off level for the hours that we examine. On the other hand, even these high cost units may have sold output under "Out of Market" arrangements with the ISO. We have not tested precisely the extent to which cost considerations could account for the output gap in August and September. These issues do not arise in June and July when RTC prices were lower.[41]

We recognize that this analysis of capacity withholding is very rough and necessarily plagued by data imperfections. Moreover, the analysis does not examine behavior of generators outside of California, and does not account for aggregation and contractual arrangements by and with wholesale marketers. A more complete analysis is not possible without access to confidential supplier data.

[41] Other "profitability" issues were raised by Harvey and Hogan (2001a), specifically in the context of June. Cardell (2001) raises such issues for later periods in the California market, when gas prices were substantially higher than during the summer period that we examine. We showed in Joskow and Kahn (2001b) that these issues were minimal in June. Harvey and Hogan (2001c) revisits them again arguing generally that all units which ran, or "should" have run, must be profitable ex post. This argument ignores the market uncertainties identified by these same authors. No bidder in any market characterized by uncertainty ex ante can be guaranteed profitability ex post. Harvey and Hogan (2001c) also raise specific issues about how profits should be estimated which are unsupported by any empirical analysis.

7. Conclusions

It is clear that increases in gas prices, increased demand, reduced availability of power imports, and higher prices for emissions permits contributed to significantly higher wholesale market prices in California during 2000, compared to the previous two years. However, based on our analysis of available data, we conclude that wholesale electricity prices in California far exceeded competitive levels during June, July, August, and September of 2000. The high wholesale electricity prices observed in Summer 2000 cannot be fully explained as the natural outcome of "market fundamentals" in a competitive market since there is a very significant gap between actual market prices and competitive benchmark prices that take account of these market fundamentals. Moreover, there is considerable empirical evidence to support a presumption that the high prices experienced in the Summer of 2000 reflect the withholding of supplies from the market by suppliers (generators or marketers). We base these conclusions on results of the two analyses described herein:

- **Competitive Benchmark Price Analysis**: Observed prices in California in Summer 2000 were greater than benchmark competitive price levels. These differences are not fully explained by higher loads, reduced levels of imports, high gas prices or by high prices for NOx RTCs.

- **Capacity Withholding Analysis**: The information that we have available to us suggests that withholding of capacity in SP15 to drive up price occurred during Summer 2000. We find a substantial gap between maximum possible levels of generation and observed levels in those hours identified aseconomical for all in-state generation. This gap cannot be explained by the CAISO's requirements for ancillary services or by reasonable estimates of forced outages. While our analysis of withholding is necessarily limited by the data available to us, there is sufficient empirical evidence to suggest that the high observed prices reflect suppliers exercising market power.

These empirical findings are further reinforced by the fact that the attributes of this electricity market make it likely *theoretically* that individual suppliers are likely to find it profitable unilaterally to withhold output compared to price takers in order to raise market prices. In addition we found that Duke, which appears to have entered into forward contracts that eliminated or substantially reduced its incentives to withhold output, did not exhibit any withholding behavior during Summer 2000. Just as the other suppliers acted on their unilateral incentives and withheld output, Duke acted on its unilateral incentives and did not withhold output. Thus, the empirical evidence is consistent with general theoretical expectations.

We close with some general thoughts about the use of economic analysis to identify and measure market power in electricity markets. Long before the new competitive wholesale electricity markets began operating in California, it was widely recognized that supplier market power could be a problem in deregulated electricity markets in general (Joskow and Schmalensee; Joskow, 1997) and in California in particular (Borenstein and Bushnell). Several different studies, using different data and different empirical techniques have analyzed pricing behavior in California during Summer 2000. They have all come to very similar conclusions. The evidence that there was a significant market power effect reflected in wholesale market prices in California during Summer 2000 is overwhelming. Indeed, no comprehensive studies exist that come to a different conclusion.[42]

If supplier market power is a potential problem then we must find good methods to diagnose its presence, and where the social costs of market power are significant, adopt mitigation mechanisms. Simply ignoring market power problems at this stage of the development of competitive electricity markets is not a realistic option. As with any other area of empirical microeconomic analysis, our ability to diagnose and measure market power is necessarily subject to some uncertainty, even using the best analytical tools available. That there is measurement uncertainty, that data are not perfect, and that the analyst cannot observe all reasons for supplier behavior or peer into the heads and hearts of buyers and sellers is par for the course for empirical economic analysis. These facts cannot logically provide a rationale for ignoring the best work available. Progress is made in improving the reliability of empirical economic analysis by ongoing efforts by analysts to replicate results, use different methods or better data to achieve similar goals— in this case identifying and measuring market power. Economic research that simply points to uncertainties and imperfections in data or analytical techniques employed by others, "raises questions," without providing alternative estimates of the questions on the table using improved techniques or data, may provide some help to evaluate market behavior both positively and normatively with greater precision. However, such research would be more valuable if it followed up the questions it raises about work done by others with serious analysis that provides answers to the problem of interest. To the extent that the intent of "raising questions" research is to make the case that "there are too many uncertainties to say anything about market power" we respectfully submit (a) that this is not a sound reading of the empirical literature on market power in electricity markets, and (b) that this kind of research can be easily misapplied by those with strong private interests in convincing policy makers to ignore market power problems.

The measurement of market power is also logically separable from the questions of whether and what policymakers should do about it when it is found. The problem that we have focused on here and elsewhere is to develop and apply techniques to measure the presences *and* the magnitude of market power and to understand better the conditions where it is most likely to arise. We recognize that many markets are imperfectly competitive and that it would be fruitless, and probably counterproductive, for policymakers to try to achieve perfectly competitive markets. However, the measurement techniques and applications presented here and elsewhere can be of value to policymakers to determine whether market power problems are sufficiently severe to require some policy response, and if they are, provide some modest guidance to choose among potential structural and behavioral mitigation measures.

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[42] Harvey and Hogan's papers raise "questions" and identify "uncertainties" but do not put them together to come up with alternative estimates.

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9. Appendices

These Appendices present data underlying our analysis and/or illustrating our methods.

A. Net Import Adjustment

The following table shows actual PX prices, estimated marginal costs using our methods ($35 RTC price in this case), actual net imports, and estimated competitive net imports for the top 15 load percentiles in August 2000. Our estimates of competitive net imports are below observed net imports when our estimates of marginal costs are below observed PX prices. At the 97th percentile, net imports above those observed are required to clear the market. We use our elasticity relationship to find the price of imports required to induce the capacity needed to clear the market. That price is above the observed PX price and represents the kind of Out of Market (OOM) transaction that the ISO entered into under such conditions.

Table A1. Sample Net Import Calculation for August 2000

Load Percentile	PX Price [1]	MC [2]	Actual NI [3]	Estimated NI [4]
85	232.13	99.33	3675	2769
86	258.92	93.89	4427	3157
87	326.22	102.54	4087	2779
88	234.91	102.14	4345	3292
89	307.11	102.54	4301	2984
90	266.63	112.70	3889	2919
91	314.34	127.53	3682	2726
92	342.45	117.34	4823	3375
93	337.72	152.93	4795	3682
94	356.54	306.80	4786	4552
95	374.26	315.50	4165	3935
96	321.31	306.80	4518	4449
97	**373.34**	**463.72**	**4008**	**4308**
98	392.13	682.44	3929	4725
99	392.55	1162.45	3648	5238

B. Unilateral Market Power

This exercise explores the profitability of a generator withholding capacity relative to a competitive baseline in which price is set by industry marginal cost and all generation with marginal cost below the market-clearing price is dispatched. We assume that all other generators produce at competitive levels and demand is completely inelastic. Under these assumptions, the effect of withholding on price is the same as a leftward shift of the industry supply curve by the amount of withholding.

Suppose that all of a generator's capacity q_c is economic at a hypothetical competitive market-clearing price p_c. If it bid all of the capacity at below the market-clearing price, it would earn profits

$$\Pi^c = p_c q_c - c(q_c)$$

where $c(q_c)$ represents its total cost of producing q_c.

Now, suppose that the same generator can raise the market-clearing price by withholding and producing $q_l<q_c$. In this case, its profits would be

$$\Pi^l = p_l q_l - c(q_l)$$

where

$$p_l = p_c + \frac{\Delta p}{\Delta q} \cdot \Delta q$$

and Δq is the extent of the generator's withholding.

The change in the generator's profits due to withholding is then

$$\Delta\Pi = p_c(q_l - q_c) + \frac{\Delta p}{\Delta q} \cdot \Delta q q_l + \left(c(q_c) - c(q_l)\right) \tag{1}$$

The first term represents the revenue loss from producing at a lower level of output, the second term represents increased per unit revenue on remaining output, and the final term represents the cost savings from producing less. The profits from withholding are the sum of these three components.

If the generator's marginal costs at q_c and q_l are $MC(q_c)$ and $MC(q_l)$ and we assume that marginal cost is linear between q_c and q_l, then

$$c(q_c) - c(q_l) = \left(0.5 \cdot MC(q_l) + 0.5 \cdot MC(q_c)\right) \cdot (q_c - q_l)$$

Based on assumptions about the generator's marginal costs at different output levels and the slope of the industry supply curve, *i.e.* the extent to which prices rise as inframarginal capacity is withheld, we can calculate the gains from withholding a specific quantity of capacity. Table 4 shows a few numerical examples. The following table shows how to estimate the slope of the supply curve for June. The next table employs these slopes to estimate hypothetical profits from unilateral withholding.

Table B1. Calculation of the Supply Curve Slope for June 2000

Load Percentile	MCP [1]	Load [2]	Load and Reserves [3]	$dp/dq_{\text{energy and reserves}}$ [4]
5	42.44	20,778	21,402	--
15	44.47	22,504	23,179	0.001140
25	46.29	24,234	24,961	0.001023
35	51.47	26,704	27,505	0.002034
45	54.81	28,618	29,477	0.001695
55	50.04	30,716	31,638	-0.002207
65	52.23	32,680	33,661	0.001083
75	53.69	34,655	35,694	0.000720
85	58.83	37,036	38,147	0.002095
95	151.00	40,735	41,957	0.024187

[1] Estimated industry MC (NOx=$10/lb)
[2] Load
[3] Load and reserves=1.03*[2]
[4] $([1]-[1]_{\text{previous load decile}})/([3]-[3]_{\text{previous load decile}})$

The last table gives details of the calculation in Table 4.

Table B2. Calculation Details for Table 4

p_c	q_c	q_l	$MC(q_c)$	$MC(q_l)$	dp/dq	Revenue Loss	Revenue Gain	Cost Savings	Δ Profit
[1]	*[2]*	*[3]*	*[4]*	*[5]*	[6]	[7]	[8]	[9]	[10]
60	3,000	1,500	55	50	0.024	90,000	54,000	78,750	42,750
60	3,000	1,500	55	55	0.002	90,000	4,500	82,500	-3,000

[7]= [1]*([2]-[3])
[8]= [6]*([2]-[3])*[3]
[9]= (0.5*[5]+0.5*[4])*([2]-[3])
[10]= [8]+[9]-[7]

C. RTC NOx Credit Prices

A unique characteristic of the RTC program is that while allowances periodically expire, the settlement procedures in the program give NOx emitters up to two months following the close of the cycle period to reconcile RTC allowances with actual emissions. There is an active market in expired allowances during those two months. It is improper, however, to correlate current prices for electric power with price movements in expired allowances. Competitive prices will reflect the marginal costs of current inputs to current generation; competitive prices do not recoup unanticipated increases in sunk costs from past periods. We have therefore examined the prices of RTC NOX credits over the study period in two groups: prices for June are represented by June prices for RTCs expiring on June 30, 2000, and prices for the post-June period are represented by contemporaneous prices for RTCs expiring on December 31, 2000.

The main data issue for the SCAQMD's list of transactions at more that $4.00 is that the date given for an observation is the "registration recording date" (RRD) not the date the transaction was executed or received by SCAQMD. We believe that the lag between the RRD and the "deal date" is about 1.5 weeks. It looks like almost all of the RRDs are either Tuesdays or Fridays plus there is a memo in the materials discussing the receipt of a transaction at $30 on the 27th of July. The RRD for this transaction is the 4th of August.

With that caveat, we reviewed transactions over time for RTCs both for the period ending 6/30/00 and for that ending 12/31/00. The graphs of these transactions by estimated date are shown below. On the basis of these data, we choose $10/lb as the June RTC price, $20/lb as the July price and $35/lb as the August and September prices.

Figure C1. NOx RTC Transactions Expiring on June 30, 2000

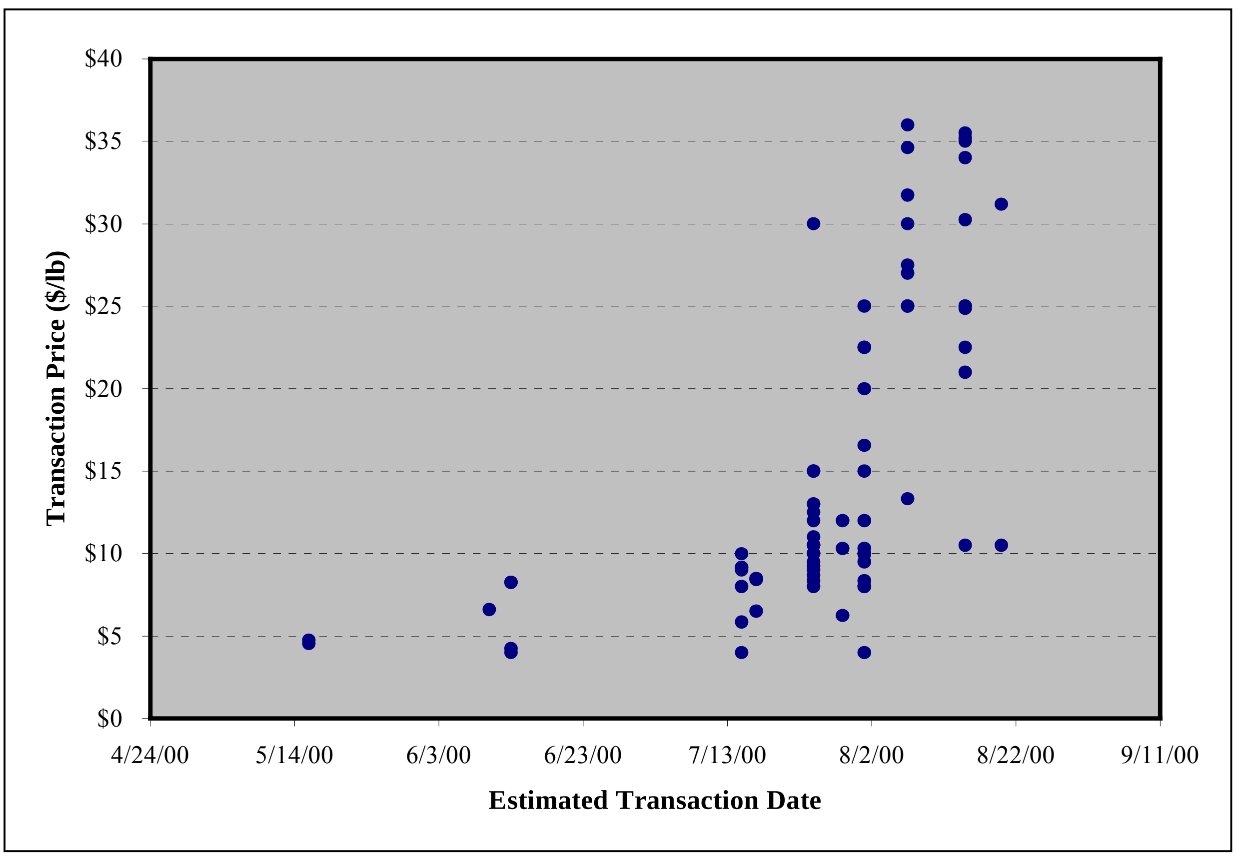

Figure C2. NOx RTC Transactions Expiring on December 31, 2000