Using Environmental Emissions Permit Prices to Raise Electricity Prices: Evidence from the California Electricity Market

by

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Abstract

This paper analyzes the extent to which the conditions in the emissions permit market for nitrogen oxides (NOx) operated by the South Coast Air Quality Management District (SCAQMD) in the Los Angeles metropolitan area interacted with competitive conditions in the California electricity market to enhance the ability of electricity suppliers with some or all of their generation units located in SCAQMD to exercise unilateral market power. We find that generation unit owners with some of their plants located in the SCAQMD paid statistically significantly higher prices for 2000 and 2001 vintage NOx emissions permits than other participants in the SCAQMD emissions market, despite the fact the prices they paid for 1998 and 1999 vintage permits were no different from those paid by other SCAQMD participants. These generation unit owners also held and allowed to remain unused a larger share of the permits available for use during the calendar year 2000 and first six months of 2001. We then present evidence consistent with the view that wholesale electricity suppliers did not operate and bid their generation units requiring NOx emissions permits as though these higher emission permit prices were actual production costs. Taken together, this evidence suggests that NOx emission permit prices during latter half of 2000 and early 2001 were used by these generation unit owners to cost-justify higher bids into the California electricity market that would set higher prices for all of the electricity they produced.

1. Introduction

The purpose of this paper is to analyze the extent to which the conditions in the emissions permit market for oxides of nitrogen (NOx) operated by the South Coast Air Quality Management District (SCAQMD) in the Los Angeles basin interacted with competitive conditions in the California electricity market to enhance the ability of electricity suppliers with some or all of their generation units located in SCAQMD to exercise unilateral market power. Several studies have demonstrated that NOx emission permit prices could be a significant factor contributing to increased fossil-fuel-based electricity production costs, and therefore substantially higher wholesale electricity prices, during the third and fourth quarters of 2000 (see Joskow and Kahn (2002) and Borenstein, Bushnell and Wolak (2002), hereafter BBW). These studies do not address the question of whether the substantially higher average NOx permit prices during this time period were the result of factors other than an increase in the demand for permits. For units located in the SCAQMD region, these studies treat the prices paid for NOx emission permits multiplied by the rate at which NOx emissions occur per MWh of electricity produced by the generation unit as part of the unit's variable costs of production. This assumption implies that emissions permit costs should therefore impact the operating and bidding behavior of generation units located in the SCAQMD region in the same manner as input fuel price changes.

We explore the validity of an alternative explanation for the behavior of NOx emission permit prices for emissions during 2000 and early 2001 and the operating and bidding behavior of generation units located in the SCAQMD region. We present evidence consistent with the view that NOx emissions permits were a convenient vehicle for enhancing the ability of suppliers to exercise unilateral market power in the California electricity market. We find that generation unit owners with some of their plants located in the SCAQMD paid statistically significantly higher prices for 2000 and 2001 NOx emissions permits than other participants in the SCAQMD emissions market, despite the fact the prices they paid for 1998 and 1999 vintage permits were no different from the prices paid by other SCAQMD participants. These generation unit owners also held and allowed to remain unused a larger share of the permits available for use during the calendar year 2000 and first six months of 2001. We then present evidence that wholesale electricity suppliers did not operate and did not bid their generation units as though these higher emission permit prices were increased production costs. Taken together, this evidence suggests that NOx emission permit prices during 2000 and 2001 were primarily used by these generation unit owners to cost-justify higher bids into the California electricity market that would subsequently set higher prices for all of the electricity that they produced.

This analysis proceeds in three stages. We first analyze the behavior of NOx emission permit prices in the SCAQMD area from 1997, the year before the California wholesale market began operation, to February 2001 when the NOx emissions permit market was suspended for electricity generation facilities. This analysis divides the SCAQMD market participants into five groups: (1) generation unit owners with all of their units located in the SCAQMD region, (2) generation unit owners with some of their units located in the SCAQMD region, (3) generation unit owners with all of their units located outside of the SCAQMD region, (4) investor-owned utilities, and (5) all other market participants.

Accounting for these differences in types of purchasers of NOx emissions permits, we find that firms with some of their units located in the SCAQMD region and others located outside the region paid substantially higher prices for 2000 and 2001 vintage permits than other SCAQMD market participants, even though the prices they paid for other vintages of NOx permits were no different from those paid by other market participants. Controlling for the date of these transactions in the regression relating the NOx price to the identity of the purchaser does not alter this empirical result. We also find that the firms that stood to gain from increases in emissions permit prices held a relatively larger share of unused permits (permits that were held by firms but not used to cover any emissions and discarded at the end of the compliance period) for periods in which price increases were valuable (the summer of 2000).

The second stage of the analysis assesses the extent to which NOx prices are treated as actual production costs by generation unit owners in the SCAQMD region. We compare the hourly generation unit-level output of the 92 fossil fuel units in California that were used in BBW to the expected (over 100 Monte Carlo simulations) hourly output of each of these units from the BBW benchmark pricing simulations. These simulations assume that each unit's variable cost of production is the sum of the following three components: (1) NOx emission costs for units located in SCAQMD (the generation unit's NOx emissions rate times the NOx emissions permit price), (2) fuel costs (the generation unit's heat rate times the price of the input fossil fuel), and (3) variable operating and maintenance costs.. We find that even after controlling for generation unit-level fixed effects, the difference between the actual hourly output of the generation unit and the expected hourly output from the BBW benchmark pricing simulation is substantially higher for units located in the SCAQMD region in 2000 relative to 1999 and 1998. Regressions that added the level of NOx emissions costs—the product of the unit's NOx emissions rate times the NOx emissions permit price—found that units with higher NOx emissions costs had systematically larger differences between actual hourly production and the level of production predicted by BBW benchmark pricing in 2000 relative to 1998 and 1999. These results imply that even though unit owners in SCAQMD faced what appeared to be substantially higher production costs because of the higher purchase prices for NOx emissions permits in 2000 relative to 1998 and 1999 described earlier, these units were run far more intensively relative to the levels that would have been predicted from the BBW competitive benchmark pricing dispatch algorithm that assumes these NOx emission costs are part of a unit's actual variable costs of production.

Our third line of inquiry builds on the results in Wolak (2003b), which quantifies changes in the firm-level incentives of the five large electricity generation unit owners in California–AES/Williams, Duke, Dynegy, Mirant and Reliant–to exercise unilateral market power in California Independent System Operator's (CAISO) real-time market from 1998 to 2000. Wolak (2003a and 2007) derives a model of expected profit-maximizing bidding behavior in a wholesale market that can be used to recover estimates of a generation unit-level variable cost functions. We apply this methodology to the hourly bids by these five generation unit owners in the CAISO real-time energy market during the months of June to September of 1998, 1999, and 2000 to estimate generation unit-level variable cost functions for the units owned by the five large fossil fuel suppliers.

The variable cost of each fossil fuel generation unit is assumed to be the sum of input fuel costs for that unit (the price of the input fuel times the heat rate of the unit) and, when applicable, the cost of NOx emissions permits for that generation unit (the price of NOx emissions permits times the NOx emissions rate of the unit), and variable operating and maintenance costs. The coefficients on input fuel costs for each firm are not statistically significantly different from one for all five suppliers, suggesting fuel costs are an actual variable cost of producing electricity. In contrast, the coefficients on NOx emissions costs are jointly statistically significantly less than one for all suppliers with units in SCAQMD, suggesting that NOx emissions permit costs were not treated as a variable cost of producing electricity in the same way as input fuel costs.

These three sets of results cast doubt on the validity of a maintained assumption in much of the analysis of the costs of California electricity crisis, that NOx emissions permit costs were a substantial component of the variable cost of producing electricity during the crisis period for units located in the SCAQMD. Instead, these results argue in favor of excluding substantial fraction or all NOx emission permit costs from the variable cost of units in the SCAQMD region when computing the competitive benchmark prices necessary to determine the magnitude of unilateral market power exercised during the California crisis period.

Our results also underscore the importance of coordinating the design of any environmental market with the resulting product markets that produce the emissions. Inefficiencies in the product market can allow firms to influence the production cost of the highest variable cost unit operating through purchase of emissions permits, particularly if the monitoring and design of the emissions market allows purchasers to increase permit prices. As emissions permit markets are used to deal with a widening range of environmental problems this issue is likely to become an increasing concern for policy makers. For example, in Spain's wholesale electricity market Linares et al. (2006) find evidence that the introduction of the European Emissions Trading System (a greenhouse gas emissions permit market) can cause large increases in electricity prices leading to large revenue increases for generation firms. This mechanism for electricity price (and revenue) increases is consistent with our study if plants requiring CO_2 emission permits to operate are needed to serve demand and the owners of these plants possess unilateral market power in the electricity market. The oligopoly model of the Spanish electricity market in Linares et al. (2006) implies that these generation unit owners are able to set market-clearing prices above the variable cost of the highest cost unit producing electricity and that this variable cost reflects input fuel costs and the cost of emissions permits, so that the market-clearing price of electricity paid to all generation units is higher than it would be in the absence of a CO_2 emissions permit market.

The remainder of the paper proceeds as follows. In the next section we describe the important institutional details of the SCAQMD NOx emissions permit market. We also present a number of summary statistics on the behavior of permit prices, the number of transactions and average transaction volume over time and across vintages. Section 3 describes the interactions between the California electricity market and the SCAQMD NOx emissions permit market. Specifically, we outline how NOx emissions permits might be used by suppliers with units located in SCAQMD to enhance their ability to exercise unilateral market power in the California electricity market. Section 4 describes the data used and motivates the econometric models estimated for the three lines of empirical inquiry summarized above. This section also describes our empirical results and performs some sensitivity analysis. Section 5 states our key conclusions, avenues for future study and, finally, we provide a brief discussions of other settings in which this type of interaction may be of concern.

2. The South Coast Air Quality Management District and the RECLAIM Market

The South Coast Air Quality Management District (SCAQMD) is the regulatory agency in charge of controlling air pollution throughout the Los Angeles Basin. The SCAQMD region includes Los Angeles, portions of San Bernadino, Orange, and Riverside counties (see Figure 1 below). SCAQMD is tasked with reducing emissions of criteric pollutants, particularly Nitrogen Oxides (NOx). One component of this effort is the Regional Clean Air Incentives Market (RECLAIM). The RECLAIM market began operation in 1994. Included in this market are any firms in the jurisdiction of the SCAQMD emitting more than 4 tons of NOx and/or SOx annually. Certain “essential public services”, such as public transit, fire stations and landfills are exempted and remain under command and control regulation of their emissions.

The market began with 390 participants, though this number fell over time by way of entry and exit from the program (some facilities reduced their emissions beyond the scope of RECLAIM’s jurisdiction and others moved their facilities outside the SCAQMD). By 2001, the end of our study period, there were 364 market participants. Each actor in the market receives an annual allocation of RECLAIM Trading Credits (RTCs). Each RTC is the equivalent of one pound of emissions in a given year (the vintage of the RTC). These vintages are for one year from a start date determined by the “cycle” in which a firm is randomly placed. Cycle 1 lasts from January 1 to December 31 of the same year whereas Cycle 2 is the period from July 1 of the vintage year to June 30 of the following year. Firms are assigned to one of these cycles at random. RECLAIM market participants can trade RTCs for either cycle to obtain the RTCs to cover their NOx emissions. The cycle assignment of a firm determines the time at which it must rationalize its NOx emissions for that year with the RTCs it holds. This must be done either as of December 31 or June 30 of the year depending on the cycle assignment. The rationale behind the cycle system was to facilitate the creation of a liquid market for permits and to reduce the potential for large price swings because all facilities would end of their annual compliance period at the same time.

Each firm in RECLAIM receives an allocation of RTCs of different vintages that may be traded. The allocation level for the initial vintage year was determined based on historical emissions levels. Specifically, firms were allowed to set baseline levels using actual emissions in one of the years between 1989 and 1992 (a concession necessitated by the political climate of the early 1990s recession years (Coy et al. 2001)). These annual allocations were then reduced at facility-specific rates until they reached desired emissions levels for the SCAQMD in 2003. Rates of allocation reduction are based on the reductions that each industry would have had to achieve under the SCAQMD air quality management plan that existed prior to RECLAIM.

The total quantity of RTC allocations was reduced from the initial allocations at an annual rate of 8.3% until 2003 (Coy et al. 2001). Given the initial allocations and rates of reduction achieved over time, the total allocation of RTCs to all RECLAIM firms was larger than total emissions through 1999. Figure 2, taken from Coy et al. (2001), shows the time pattern of annual allocations of RTCs and total annual emissions.

The most dramatic emissions reductions required by SCAQMD were to come from electricity generating facilities and oil refineries. These two industries were allocated 56% of the total initial NOx RTCs. The NOx RTC allocation for power plants was to be reduced by 81% by 2003 relative to their initial allocation and refineries were given an allocation in 2003 that was 67% lower than their initial allotment (Coy et al. 2001). A key issue to note here is that these changes in allocations do not actually reflect the necessary reductions that firms in these two industries had to make. As mentioned earlier, the initial allocation of RTCs was larger than the total amount of NOx emitted at the beginning of the market. Because initial RTC allocations were set so high relative to NOx emission levels at the start of the RECLAIM market, these two industries were estimated to have only had to have make actual reductions in emissions of 67% for power plants and about 48% for refineries by 2003 (Coy et al 2001).

In the three months following any RTC trading period (Cycle 1 or 2 in any year) a firm must rationalize all of its emissions with the required number of emissions permits. If a firm expects to emit more than their initial allocation in a given year they have two choices. First, they can reduce their emissions by installing the necessary emission reduction technology available. The other option, and the only one available in the short term, is to purchase RTCs from other actors in the RECLAIM market. In theory, the ability to trade RTCs allows all RECLAIM entities to achieve the aggregate emissions level mandated by the SCAQMD at a lower cost than command and control methods. Firms with the lowest marginal cost of pollution reduction have the strongest financial incentives to undertake these investments given the opportunity cost of holding RTCs, which is the price at which they can sell their RTCs to another market participant.

Trades to obtain the necessary RTCs fall into one of three categories: (1) intercompany trades, (2) trades involving non-RECLAIM facilities and (3) intra-company trades across facilities (Burnside and Eichenbaum 1996). During our sample period, trades could either be directly negotiated or could flow through one of the two major brokers that handled RECLAIM transactions: Cantor Fitzgerald and the Pacific Stock Exchange.

The RECLAIM market appears to have behaved in a distinctly different manner prior to 2000 and 2001. These differences are consistent with the fact that before 2000 it was unlikely that generation unit owners could use RTC permit prices to enhance their ability to exercise market power in the California electricity market. Furthermore, it simply would not have been credible to argue that NOx emissions permits for prior vintages were worth anything substantial given the difference between the total allocation of RTCs and the amount used in all years before 2000 shown in Figure 2. In contrast, for 2000 and 2001, suppliers could credibly argue that the constraint on NOx emissions permits in SCAQMD was likely to be binding so that RTCs of these two vintages would have been of value to all RECLAIM participants, including electricity generation unit owners.

The price increase for the 2000 and 2001 vintage RTCs that occurred starting in 2000 is dramatic. Both annual mean prices and monthly transaction-volume-weighted-average prices show large increases in 2000 and 2001 (see Figures 3 and 4). For example a vintage 2000 RTC traded in 1999 had an average price of $2.25 per lb of NOx compared to $21.11 in 2000 and $23.19 in 2001 (recall that due to cycle assignments the market for cycle 2 2000 permits remained active in 2001).

Because most participants in the RECLAIM market that do not primarily generate and sell wholesale electricity face substantial competition for their output from firms located outside of the SCAQMD, we would expect them to have strong incentives to purchase additional RTC permits beyond their initial allocation at the lowest price possible during 2000. In contrast, wholesale electricity generators may want to raise RTC permit prices to enable them to cost-justify high bids (or signal to other market participants their intention to submit higher bids) to supply electricity during this same time period. Where this holds, divergent incentives facing RTC permit buyers during 2000 should be observable in an increased variance in transactions prices during this time period.

Figure 5 shows that the standard deviation of RTC transaction prices for 2000 and 2001 vintage permits increased substantially in 2000. The timing of this increase in variability of transactions prices lends support to the view that wholesale electricity suppliers owning facilities both inside and outside of the SCAQMD faced the opposite incentive from other buyers in the RECLAIM market during this period because RTCs could be used to raise wholesale electricity prices in California.

In addition, if RTC prices were used to cost justify higher bids into the wholesale electricity market, the increased bid price would be necessary only on a small amount of additional electricity that sets the market-clearing price for the entire state of California or the South of Path 15 (SP15) congestion zone. If this strategy was being used, we would expect generation owners to purchase the smallest quantities necessary to cost justify (or signal the intention to submit) the higher bid price for electricity rather than buying large quantities of RTCs at these inflated prices. Comparing average transaction volume for 2000 and 2001 vintage RTCs, we find a sizeable drop in the transaction size in 2000 and 2001 relative to previous years. Figures 6 shows the decrease in average transaction size which is consistent with our hypothesis for how NOx emission permits were used by generation unit owners in 2000. Figure 7 also reveals behavior consistent with this strategy. The number of RTC transactions of these two vintages increased significantly in 2000. By 2001 the average number of RTCs per transaction had fallen to 11,900 from a peak, in 1998, of 134,000. The use of smaller and more frequent RTC trades is consistent with the use of RTC prices as a mechanism for increasing the market-wide electricity price, although there are clearly other possible explanations for these observations.[1]

3. The RECLAIM Market and California's Restructured Electricity Market

Several features of the California electricity market are crucial to understanding how generation unit owners might use the RECLAIM permit market to enhance their ability to raise wholesale electricity prices. This section describes those features of the California electricity market. We then briefly summarize the performance of the California electricity market from April 1, 1998 until the winter of 2001 and how events in the electricity market impacted events in the RECLAIM market. This discussion will provide context for our subsequent analysis of the

[1] For example, the amount of unused vintage 2000 and 2001 RTCs that individual RECLAIM participants have to sell are much smaller in 2000 than in previous years.

behavior of RECLAIM permit purchase prices in 2000 and 2001 relative to the period from 1997 to 1999, and the impact these RECLAIM prices had on how generation units owner's decisions to operate generation units and bid them into the CAISO's real-time energy market.

3.1. Market Structure and Market Rules in California Electricity Market

According to the California Energy Commission (2001), during our sample period, more than 50% of the capacity in California was oil or natural gas-fired steam and combustion turbine facilities, with all but a few peaker generation units being natural gas-fired. Roughly 60% of this gas-fired capacity is located in the SCAQMD region and is therefore included in the RECLAIM market. Many of these facilities have very high heat rates, which puts them at upper end of the state-wide marginal cost curve computed based on input fuel costs and variable operating and maintenance costs. When the price of RECLAIM permits is nonzero more units inside SCAQMD can be expected to be at the upper end of the statewide marginal cost curve because they must incorporate the price of emissions permits into their operating costs.

Because there is considerable disparity in NOx emissions rates across generation units in RECLAIM, with some emitting 0.10 lbs of NOx per MWh of energy produced and others emitting more than 5 lbs of NOx per MWh of energy produced, increases in NOx emissions permit prices can alter the least cost dispatch of generation units in California. For example, suppose the natural gas-fired unit with a NOx rate of 0.10 lbs/MWh has a higher heat rate than the unit with a NOx rate of 5 lbs/MWh. If the price of RECLAIM permits is high enough then the least cost dispatch could require the higher heat rate unit to be dispatched instead of the lower heat rate unit.

A second important feature of the California market is that for all hours during our sample period, California set market-clearing prices for electricity over geographic areas larger than the area covered by the RECLAIM. For the vast majority of hours there was a single state-wide price, but when there was transmission congestion across southern and northern California, separate market prices were set for these two geographic regions, called the SP15 and north of Path 15 (NP15) congestion zones. On February 1, 2000 a third congestion zone was added in southern California called the ZP26 congestion zone. Even after the addition of the ZP26 congestion zone, the SP15 congestion zone remained significantly larger and contained more gas-fired generation capacity than the SCAQMD region.

If the area over which prices are set in the electricity market covers a larger geographic area than the SCAQMD, a wholesale supplier with units located both in and outside of the SCAQMD service territory may have an incentive to bid up the price of NOx permits in order to increase the apparent production costs of a permit-using unit that it expects will set the market-clearing price of electricity for the entire state or the larger SP15 congestion zone that contains SCAQMD. During the sample period, there were a number of merchant power producers in California that owned generation units both in and outside of SCAQMD.

The logic underlying this strategy is illustrated in Figure 8, which plots the systemwide marginal cost curve with zero RECLAIM permit prices and the systemwide marginal curve with positive RECLAIM prices. There are two sources of increased profits that result from higher RECLAIM prices. The first is the increased profits earned by generation units that do not have NOx emissions permit costs, because they are not located in the RECLAIM area but are still paid the market-clearing price. This is the area labeled "Additional profits to units without NOx costs" in Figure 8. The second source of increased profits associated with higher RECLAIM prices result from the fact that marginal costs increase much more for a given dollar increase in RECLAIM prices for units with higher NOx emissions rate. In the example in Figure 8, the marginal costs of the highest cost generation unit operating increases by twice as much as the variable cost of the other unit with NOx emission costs because it has a NOx emissions rate that is half the value of the highest cost unit operating. This unit earns the area labeled "Additional profits to unit with lower NOx emissions rate" as a result of the increase in the NOx price. This logic also demonstrates why a supplier with all of its units located in the SCAQMD might still want to increase the price of NOx permits if its units have significantly different NOx emissions rates.

Figure 9 plots the cumulative distribution by generation capacity of NOx emissions rates within the SCAQMD region. If, as is the case for several California wholesale suppliers, the firm has generation capacity at the low end and high end of this NOx emissions rate distribution, the strategy outlined above may be profitable. Even if the supplier had to pay the permit price in order to produce any electricity from its units, if the price of electricity was set by the unit with the highest variable cost of production (including NOx emission permit purchases), the supplier would earn additional profits on all of its units with lower NOx rates because any RECLAIM permit price is multiplied by a lower NOx emissions rate in computing the variable cost of the units owned by this supplier. Consequently, these variable costs would not increase by as much as the market-clearing price, which is likely to be set by the generation unit with the highest combination of NOx emissions costs and fuel costs. Moreover, as noted above, for high enough RTC prices, the unit with highest variable cost is the one with the highest NOx emissions rate.

Regardless of the RTC purchasing strategy of an electricity supplier with some or all of its units located in the SCAQMD, we would expect that as the price of NOx permits rises all firms interested in raising electricity prices would withhold lower cost units from the market in order to make it more likely that their high cost units (that include very high NOx permit costs) would set the price received by all of their units. Consequently, one implication of higher NOx permit prices in an electricity market where firms have the ability and incentive to exercise unilateral market power is a bias in favor of operating high NOx permit cost plants in order to raise market prices. In contrast, in a competitive electricity market, we would expect that competition among generators to serve demand would lead to high NOx emissions cost units being dispatched less frequently given their variable cost disadvantage relative to other generation units.

3.2. Enabling Initial Conditions in California Electricity Market

The successful use of RTC permit prices to raise wholesale electricity prices requires a number of initial conditions in the California electricity market. Specifically, without initial conditions that made it unilaterally profitable for suppliers to withhold energy from the California market (either through bidding significantly in excess of the variable costs of supplying electricity from their generation units or refusing to supply electricity from their units at any price) it would have been much more difficult to use RTC permits in the manner we hypothesize.

Had the day-ahead and real-time California electricity markets been workably competitive, with a sufficient number of suppliers able to provide the CAISO control area's incremental day-ahead and real-time electricity needs at all locations within SCAQMD and the rest of California, suppliers required to purchase RTCs to produce electricity would find themselves at a competitive disadvantage relative to other suppliers in the CAISO control area. This would lead to their units being dispatched much less frequently than units that did not have to purchase RTCs. Moreover, those units with the highest NOx emissions rates would be at the greatest disadvantage relative to other suppliers with units in the SCAQMD and these units would be dispatched only when the demand for electricity in the SP15 congestion zone or in California is extremely high. Because suppliers requiring RTCs to produce electricity are at such a cost disadvantage in a workably competitive wholesale electricity market, they would have strong incentives to pay as little as possible for NOx emissions permits, precisely the opposite incentive they face in market where suppliers have the ability to exercise a substantial amount of unilateral market power using higher permit prices to cost justify higher offers or to signal to other suppliers their intention to submit higher offers.

Wolak (2003b) uses the bids submitted by all market participants to CAISO's real-time energy market to quantify changes in the ability to exercise unilateral market power of the five large fossil-fuel generation unit owners in California during the summers of 1998 and 1999 relative to the summer of 2000. BBW estimate the magnitude of systemwide market power exercised in the California electricity market from June 1998 to October 2000. They find a substantial increase in the aggregate amount of market power exercised beginning in May of 2000, which is consistent with the substantial increase in the ability of each of five large fossil fuel suppliers in California to exercise unilateral market power during the summer 2000 relative to the previous two summers documented in Wolak (2003b).

BBW demonstrate that a major reason for the substantially larger amount of market power exercised during the summer of 2000 relative to the summers of 1998 and 1999 is that there were many more hours when a considerable fraction of fossil fuel generation capacity in the CAISO control area was needed to meet the state's demand for electricity. Specifically, for the summers of 1998 and 1999, during roughly 50 percent of the hours the amount of energy produced from these units was greater than or equal to 5000 MWh. For the summer of 2000, during approximately half of the hours the amount of energy produced from these units was greater than or equal to 10,000 MWh. As BBW note, this increase in the intensity of use of the within-CAISO-control-area fossil-fuel capacity during the summer of 2000 was primarily due to a substantial decline in the availability of imports. Another factor in the higher prices during the summer of 2000 was substantially higher natural gas prices starting in May of 2000 and continuing until the June 2001. Average natural gas prices in California during the summer and autumn of 2000 were almost twice average prices during that same time period in 1999.

The results in Wolak (2003b) and BBW are consistent with the view that the lower import availability in 2000 relative to 1999 and 1998 resulted in each of the five large fossil fuel suppliers facing significantly less elastic residual demand curves starting in the early summer of 2000. This made it unilaterally profit-maximizing for these suppliers and other suppliers to withhold capacity from the California electricity market in order to raise wholesale prices (by exploiting these less elastic residual demand curves) during the summer of 2000. As we argue below, the purchases of NOx emissions permits by some of these suppliers located in the SCAQMD region at inflated prices allowed them to cost justify the higher bids they submitted due to their increased ability to exercise unilateral market power during the summer of 2000. Higher natural gas prices provided an additional input cost justification for higher bids into the ISO's real-time market starting in the early summer of 2000.

The significant increase in the extent of unilateral market power exercised in the California electricity market during the summer of 2000 created a difficult public relations problem for generation unit owners in the California electricity market. It was extremely difficult for suppliers to explain the enormous increase in electricity prices in California that occurred starting in May 2000 with just natural gas price increases. Figure 10 plots the average hourly price in each of the three CAISO congestion zones for each month from April 1998 to

December 2000. Consequently, one interpretation of the behavior of price paid by generation unit owners for 2000 and 2001 vintage RTC permits is that they provided a mechanism for these firms to cost-justify substantially higher bids into the day-ahead and real-time electricity markets in California for those units located in the SCAQMD. Consider the testimony of J. Stuart Ryan of AES Corporation to the Federal Energy Regulatory Commission (FERC) in which he said, "To the extent there is a smoking gun, it's NOx. The cost of credits for NO_x emissions in the L.A. Basin have skyrocketed."[2] Comparing Figure 10 to Figure 11, we can see that the increase in electricity prices during the summer of 2000 that started in May 2000 roughly coincides with the increase in NOx emissions permit prices. However, even after accounting for NOx emission permit prices shown in Figure 11 in their competitive benchmark price computations, BBW still find an enormous increase in the amount of market power exercised in the California electricity market beginning in May 2000. The results of Wolak (2003b) explain this increase in unilateral market power exercised as a result of the enhanced ability of suppliers to exercise unilateral market power in the summer of 2000 relative to the previous two summers.

High NOx emissions prices provided a convenient tool for justifying increasingly higher bids by SCAQMD suppliers into the day-ahead and real-time energy markets in California during the last six months of 2000 and first few months of 2001. This rationale became regulation after a soft price cap policy was implemented in early December of 2000. Under final form of this regulation ordered by the FERC, bids excepted to supply energy by the California ISO in excess of $150/MWh were required to be cost-justified. The FERC was also very generous with what it would allow suppliers to include in these costs. For example, a bid to supply electricity in excess of $3,000/MWh was accepted under this policy. Purchasing a small

[2] January 1, 2001. From *Public Utilities Fortnightly*. See article at http://www.pur.com/pubs/3639.cfm

number of RTCs at sufficiently high prices was an effective means of cost justifying a higher bid, particularly for generation units with high NOx emissions rates.

We now turn to our evidence in favor of the view that the increases in NOx emissions prices described in Section 2 and summarized in Figure 11 were used to cost justify higher bids into the California electricity market and therefore increase wholesale electricity prices during the summer of 2000 and beyond. As noted in Section 2, there are number of factors which suggest that the increased average prices for the 2000 and 2001 vintage RTCs during 2000 were not treated as actual increases in the cost of producing electricity by generation units located in the SCAQMD during the summer 2000. Specifically, the enormous increase in the standard deviation of transactions prices for vintage 2000 and 2001 permits during 2000 and 2001 suggests that some buyers of RTCs were not interested in finding the lowest possible price for these permits.

4. Evidence that RTC Permits Were Used to Raise Wholesale Electricity Prices

This section is divided into three parts, each of which contributes evidence in favor of the conclusion that the RECLAIM NOx emission permit market was used by suppliers with some or all of their units located in SCAQMD to enhance their ability to exercise unilateral market power in the California electricity market. We first present evidence that suppliers with some or all of their generation units located in SCAQMD paid systematically higher prices for vintage 2000 and 2001 RTC permits than other RECLAIM market participants. We also show that these same market participants held a larger fraction of the unused RTC permits that could have been used in 2000 and 2001. We then compute the difference between the actual unit-level hourly output and the unit-level expected hourly output value that results from the BBW competitive benchmark-pricing Monte Carlo simulations for each hour from June 1998 to December 2000. We find that the hourly value of this difference is substantially higher in 2000 (relative to 1998 and 1999) for units located in SCAQMD compared to other fossil fuel units in the CAISO control area. Moreover, we find that this hourly difference in 2000 is higher for units in SCAQMD with higher NOx emissions rates, implying that units with higher emission rates are run relatively more intensively compared to the amount they would be operated had there been a workably competitive wholesale electricity market in California during the summer of 2000. Finally, we use the results of Wolak (2003a and 2007) to recover hourly estimates of the marginal cost of producing electricity from each generation unit owned by each of the five large fossil-fuel generation unit owners in the California electricity market. We find that, consistent with fuel costs being an actual expense incurred to produce electricity, a one dollar increases in input fuel costs—the unit's heat rate times the price of natural gas—is associated with a one dollar increase in the estimated marginal cost for that generation unit. Consistent with our argument that NOx emissions permit prices were not treated as input costs in the same manner as input fuel costs, we find that a one dollar increase in NOx emissions permit costs—the generation unit's NOx emissions rate times the NOx emissions permit price—is associated an increase in the estimated marginal cost that is substantially less than one.

4.1. RTC Transaction Prices and Buyer Identity

This section first presents the results of our analysis of the prices for all RTC transactions with positive prices that occurred for permits with vintages from 1997 to 2001. We focus our analysis on these vintages rather than include earlier ones because we believe it was unlikely that participants in the RECLAIM market thought the wholesale electricity market in California would begin operation before January 1, 1997, which is fifteen months before it actually began operation. We also excluded all transactions that occurred after June 1, 2001, by which time electricity generators had been fully excluded from the RECLAIM market. This yields a total 1,792 transactions.

To present our regression results, define the following notation:

ln(p(i)) = natural logarithm of the price paid for a NOx permit for transaction i.

Wholesale(i) = an indicator variable that equals 1if the parent company of the buyer for transaction i is a non-utility owner of generation units in the CAISO control area

Utility(i) = an indicator variable that equals 1 if the parent company of the buyer for transaction i is one of the three California investor-owned utilities

AQMD(i) = an indicator variable that equals 1 if all of the units owned by the parent company of the buyer for transaction i are located in SCAQMD

InOut(i) = an indicator variable that equals 1if some of the units owned by the parent company of the buyer for transaction i are located in SCAQMD, and others are not

Out(i) = an indicator variable that equals 1if all the units owned by the parent company of the buyer for transaction t are located outside of SCAQMD

Year(i,t) = an indicator variable that equals 1if t is the vintage year of the RTC permit for transaction i

TransYear(i,t) = an indicator variable that equals 1 if t is the year that transaction i occurred.

According to our interpretation of SCAQMD records the wholesale electricity suppliers with all of their units in the region during our sample period are AES/Williams and Thermo Ecotech. Suppliers with some of their units in the region are Dynegy and Reliant. Duke and Mirant do not own units located in the SCAQMD region.

Table 1 reports the results from estimating the following regression

$$
\begin{aligned}
\ln(p(i)) = {} & \alpha_0 + \sum_{t=1998}^{2001} \delta_j Year(t,i) + \beta_1 Wholesale(i) * AQMD(i) + \beta_2 Wholesale(i) * InOut(i) \\
& + \beta_3 Wholesale(i) * Out(i) + \beta_4 Wholesale(i) * Utility(i) + \gamma_{00} Wholesale(i) * AQMD(i) * Year(00,i) \\
& + \gamma_{01} Wholesale(i) * AQMD(i) * Year(01,i) + \lambda_{00} Wholesale(i) * InOut(i) * Year(00,i) \qquad (3) \\
& + \lambda_{01} Wholesale(i) * InOut(i) * Year(01,i) + \eta_{00} Utility(i) * Year(00,i) \\
& + \eta_{01} Utility(i) * Year(01,i) + \delta_{01} Wholesale(i) * Out(i) * Year(01,i) + \varepsilon_i
\end{aligned}
$$

Consistent with our hypothesis, the estimates of γ_{00}, γ_{01}, λ_{00} and λ_{01} are all positive, and all but the estimate of γ_{00} are precisely estimated. Moreover, we find that the joint null hypothesis: $\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ cannot be rejected. These two results imply that after controlling for the vintages of permits being purchased in transaction i, none of the four types of market participants paid higher average prices for 1997, 1998 and 1999 vintage RTC permits. For 2000 and 2001 vintage RTC permits, wholesale electricity suppliers with some or all of their plants located in the SCAQMD district paid higher average prices for RTC permits than all other RECLAIM market participants. Although they are not very precisely estimated, the point estimates of η_{00} and η_{01} are negative, indicating that the three California investor-owned utilities paid lower prices for 2000 and 2001 vintage RTC permits than did other RECLAIM market participants.

One possible explanation for these results could be a composition effect associated with the date the RTC permits were purchased. Specifically, different participants made purchases at different times and this explains why the average prices they paid are higher for vintage 2000 and 2001 permits. For this reason, we expanded regression to include seven transaction year indicator variables, TransYear(I,t) for t=1995 to 2001. Table 2 reports the results of this regression. Although the transaction year indicator variables for 2000 and 2001 are estimated to be very large and positive, the estimates of γ_{00}, γ_{01}, λ_{00} and λ_{01} remain positive though, in contrast to Table 1, only λ_{00} and λ_{01} are precisely estimated. The joint null hypothesis:

$\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ still cannot be rejected. The point estimates of η_{00} and η_{01} are positive, but very imprecisely estimated.

The results in Tables 1 and 2 show that wholesale suppliers with some units in the SCAQMD and others outside paid on average from 21% to 27% higher prices for 2000 vintage RTCs and from 25% to 30% higher prices for 2001 vintage RTCs than all other RECLAIM market participants. The corresponding ranges for suppliers with all of their units in the SCAQMD region are from 11% to 17% higher for 2000 vintage RTCs and from 13% to 31% higher for 2001 vintage RTCs, although these results are not estimated with same degree of precision as those for the InOut suppliers.

These results raise the question of how a functioning market could sustain such deviations in price between different parties. In the years in which it was profitable for generation firms to pay high prices for RTC permits we see a large increase not only in the average price of permits but also in the variance of prices across transaction (Figures 3-7). In addition, the volume traded per transaction dropped significantly (Figure 6). The high variance in transactions prices is inconsistent with a well functioning market where the majority of participants expected permit prices to rise. Given the significant presence of large brokerage firms in the secondary market for RTCs, if there was widespread agreement among market participants on permit prices the variance in transaction prices would not be as large or, at least, would have diminished over time. Consequently, it seems plausible that brokers may have functioned in a supporting role to generation firms trying to obtain high priced RTCs in specific periods.

The RECLAIM market included an eclectic set of firms, ranging from very small companies, unlikely to consider their emissions permit allocation as a valuable asset to the business, to large electricity generation firms that require permits for every MWh of electricity sold. In this setting a broker could approach smaller firms and offer a price slightly greater than their reservation value for the RTC asset. The broker could then hold these assets and sell them to generators at very high prices. These smaller players were unlikely to have been fully aware of the value of their RTC holdings and may therefore have been willing to sell at a significantly lower price than at the one at which the broker could subsequently sell the RTC to an electricity producer located in SCAQMD.

Evidence for such a model can be seen by analyzing the average spread between purchase and sale price for RTCs where a broker facilitated the transaction. Using the RECLAIM trade data we compute the difference between price paid for RTCs by brokers and the sale price to generators with units inside and outside the RECLAIM market, generators with units only inside, and to all other participants in the market. Table 3 presents the average difference for these groups by year. For 2000 and 2001 vintage RTCs, brokers appear to be taking significant losses on trading with non-generation firms.[3] On the other hand trades made with generation unit owner with facilities inside and outside of the RECLAIM region were profitable for both 2000 and 2001 vintage permits. Trades of 2001 vintage permits were also profitable when the buyer was a wholesale electricity supplier with generation units only inside the SCAQMD area. This is consistent with the results presented in 4.1 in which estimates of γ_{01}, λ_{00} and λ_{01} are greater than 0 and precisely estimated, but γ_{00} is not. For every vintage of permit and buyer type whose behavior is consistent with strategic use of RTC permits, brokers appear to have made very large

[3] Brokers were also paid a transaction fee, typically a percentage of the total transaction cost. This would have allowed them to recoup the cost of these trading losses. This analysis was done using RECLAIM transaction data. Thus we do not have data on the terms of the fees or the amount that brokers may have made.

spreads, whereas for all other transactions they actually lost money on average, at least on the basis of transactions prices.

Taking a closer look at one of the largest brokers in the RECLAIM market provides an example of how brokers might have found facilitating generator behavior to raise transactions prices for NOx permits a profitable enterprise. This broker made a significant number of trades in the RECLAIM market and had been active in the market since its inception. It traded on behalf of generation firms (both InOut and AQMD type firms) throughout their operation in the RECLAIM market, before and during the "California Electricity Crisis" period. However, the broker dramatically increased work with generators in periods in which it was profitable to pay very high prices for RTCs. Specifically, 1998 and 1999 vintage RTCs sales to InOut generators were only 2.44% and 7.91% of the firm's total sales in the RECLAIM market. For 2000 and 2001 permits, however, sales to InOut generators jumped dramatically to 29.55% and 12.37% of sales for those respective vintages. This change is not unexpected, viewed in light of the profitability of trading with generators, but it does underscore the potential gains brokers would have made by finding low priced permits on the "illiquid" or smaller side of the RECLAIM market and selling to generators in high willingness to pay periods. The broker's trades with generators with units solely inside the SCAQMD also increased for 2000 and 2001 vintage permits. In fact, for 2000 vintage permit sales 44% of their sales revenues was with generation unit owners with units both inside and outside of SCAQMD or only inside SCAQMD.

Because holding permits and allowing them to expire unused is likely to impact permit prices, we now analyze the volume of unused RTCs held by different market actors. RECLAIM rules do not allow participants to bank RTCs for use in later compliance periods. Consequently, Cycle 1 2000 vintage permit effectively becomes worthless for offsetting emissions outside of

January 1 to December 31, 2000 time period. Firms that stood to gain from high RTC prices could hold RTCs that are valid for a compliance cycle in excess of their actual emissions during that compliance cycle, which would reduce the supply available to market participants and raise permit prices, which would then allow higher electricity prices to be cost-justified based on NOx emissions permit costs. In order to test for the existence of this withholding behavior, we compute a measure of the total RTCs held for each vintage by a firm i (the allocation to the firm net of purchases and sales) and the stock of emissions over that period by firm i. The difference is the unused permits for firm i for period t.[4]

We compute the volume of unused permits by vintage from 1997 to 2000 for each of the three large fossil fuel suppliers with units in SCAQMD, Los Angeles Department of Water and Power (LADWP), energy and permit trading firms registered in the RECLAIM market and a residual category of other small fossil-fuel generation unit owners. We do not include 2001 permits because generators were excluded from the market beginning in February of that year. In addition, we compute holdings and emissions for the entire firm, as opposed to by individual RECLAIM facility identifiers. This is done to account for the fact that permits allocated to a firm for specific generation units or facilities could easily be re-allocated between different RECLAIM entities in their portfolio. For example, two of the three large fossil-fuel generation unit owners have more than one generation facility the SCAQMD region and therefore many unique facility identification numbers that they can allocate RTCs across. A firm-level, rather facility-level, unit of analysis accounts for the fact that RTCs held by any of the facility

[4] We are grateful to Stephen Holland for providing the data from Holland and Moore (2007) used to compute these measures.

identification numbers owned by that firm could be used to offset emissions at any of the firm's generation units.

We first compute the total unused permits for different types of market actors. The definition of an unused permit is an RTC available to a firm that was not offered to offset one pound of NOx emissions at the end of the compliance period. These results are presented in Table 4 below. The three merchant generators vary in the number of unused permits they hold by vintage between 1997 and 2000. We first note the large volume of unused permits held by Generation Firm 1 for the 1999 vintage. For this period the combined permit holdings of entities registered to Generation Firm 1 exceeded actual emissions by almost 450,000 pound of NOx. The compliance cycle structure of RECLAIM means that Cycle 2 1999 vintage permits were available to meet emissions through the end of June of 2000. The enabling conditions for the use of RTCs to raise electricity prices were thus present in the period in which Generator 1 held permits far in excess of emissions. For 1999 vintage permits this incentive to withhold to drive permit prices up is only relevant for Cycle 2 compliance facilities because Cycle 1 facilities had to rationalize emissions with holdings as of December 31, 1999. Decomposing the overall holdings for Generator 1 across plants we find that generation units assigned to Cycle 1 had close to zero left over permits for the 1999 vintage (each power plant had 2 unused RTCs for the 1999 vintage). On the other hand, the single plant owned by Firm 1 assigned to compliance cycle 2 held 413,000 unused RTCs (or 92 percent of the unused permits held by Firm 1).

We also performed the following regression to determine the extent to which owning a generation unit in the SCAQMD predicts a higher share of unused vintage 1999 and 2000 permits. The model is similar to equation (3) but replaces the dependent variable with the unused permits held by firm i for vintage t as a share of the total unused permits of that vintage in the market. The first specification we estimate is the following:

$$\left(\frac{unused(i,t)}{\sum_i unused(i,t)}\right) = \alpha_0 + \sum_{t=1998}^{2000} \delta_j Year(t,i) * Cycle2(i) + \sum_{t=1999}^{2000} \delta_j Year(t,i) + FE(i) \tag{4}$$
$$+\gamma_{Raise}[Cycle2(i) * Year(99,i) + Year(00,i)] * Raise(i) + \varepsilon_i$$

where *unused(i,t)* is the unused permits held by firm i for vintage t and *FE(i)* is a dummy variable equal to 1 for firm i. The dependent variable is a measure of the share of "available" unused permits of each vintage across the entire RECLAIM market held by a given market actor. Interactions between vintage and the compliance cycle to which firm i is assigned are included to account for differences in market conditions during the firm's year end compliance period. *Raise(i)* is a dummy variable that equals for one for SCAQMD participants that we believe had an incentive to raise wholesale electricity prices. This includes the three large merchant generators with plants in the SCAQMD, plants owned by the LADWP and traders. We define traders to include all firms that had energy or emissions trading specific wing of the company.[5] We include a control for these companies in our regression because they were, potentially, in a position to gain from any electricity price increases that resulted from higher NOx emission permit prices. *Cycle2(i)* is a dummy variable equal to 1 if firm i has any RECLAIM actor in its portfolio whose compliance cycle is 2. The interaction of the availability of a Cycle 2 facility with the dummy for 1999 vintage RTCs captures the potential for withholding 1999 RTCs during the summer of 2000, the time at which Cycle 2 plants were required to meet emissions with RTCs. The coefficient γ_{Raise} is the coefficient of the best linear predictor for the share of

[5] This definition includes some firms that also controlled emissions producing assets in the RECLAIM area. As such some "traders" had real emissions that we include in computing firm level unused RTCs.

available unused permits held by participants with both the incentive (the ability to profit from higher prices in the statewide electricity market) and the opportunity (had a Cycle 2 facility for 1999 vintage permits or was active in the market for 2000 vintage permits) to raise RTC prices. A positive and precise estimate for γ_{Raise} is consistent with a greater share of unused permits being held by these actors.

Table (5) below presents parameter estimates for equation (4). We limit our sample to include only firms that had positive emissions in 1998, 1999 and 2000. Thus we are capturing the share of unused emissions among "active" market participants. The coefficient estimate for γ_{Raise} is .025 and is very precisely estimated. The interpretation of this coefficient is that the actors with the incentive and the opportunity to alter RTC prices are predicted to have held a 2.5 percentage point great share of the unused permits in the market in those periods in which price increases were beneficial. Considering these actors held only a very small share of the available unused permits for 1997 to 2000 vintage RTCs, this predicted increase is also economically meaningful. Furthermore, this is evidence that these firms were holding large shares of permits and leaving them unused at the same time that the prices paid for these permits were rising.

We also estimate a variant of equation (4) in which we separate those holding unused vintage 1999 permits from those holding vintage 2000 unused permits. Parameter estimates from the alternate specification are presented in Table 6. Consistent with the first specification the parameter estimates are .028 and .022 for 1999 and 2000 vintage permits respectively. Both are precisely estimated and economically significant.

Our evidence on holdings of unused RTCs seems inconsistent with cost minimization behavior by generation and trading firms in the RECLAIM market. On the other hand, holding large shares of unused permits in high price periods is consistent with the model of using permit prices to raise wholesale electricity prices that we propose. We note, however, that withholding permits is not a necessary condition to raise transactions prices for RTCs in a pay-as bid market for permits. As we discussed earlier, particularly with respect to the role of brokers, without sufficient transparency in the RECLAIM market generation firms could pay high prices for RTCs while other participants pay lower prices.

4.2. The Impact of RECLAIM Market on Generation Unit Hourly Production

This section uses the actual hourly generation unit-level output from the CAISO settlement data and the expected hourly generation unit-level output that results from the BBW competitive benchmark pricing Monte Carlo simulation to assess the impact of RECLAIM emissions prices on the production decisions of all suppliers in the CAISO control.

The objective of this analysis is to compare how fossil fuel units located in the CAISO control area operated on an hourly basis to how they would have operated had no California suppliers been able to exercise unilateral market power. The BBW competitive benchmark analysis solves for price and unit-level output quantities that would result from all suppliers in the California ISO control area behaving as if they had no ability to influence prices through their bidding or scheduling behavior. To account for the fact that the vector of hourly unit-level outputs from all fossil fuel generation units in California is a realization from the joint distribution of unit-level availabilities for all fossil fuel units in California, BBW uses information from the National Electricity Reliability Council (NERC) to construct a joint distribution of unit-level availabilities. For each hour in their sample, BBW then draw 100 realizations from this joint distribution of unit-level availabilities and compute the competitive benchmark price that results. The hourly competitive benchmark price reported in BBW (2002) is the average of these benchmark prices over the 100 realizations from the joint distribution of generation unit-level availabilities. As BBW note, computing the competitive benchmark price without accounting for the possibility of unit-level outages will tend to produce a competitive benchmark price that is too low and yield a unit-level output mix that over-uses low cost generation units relative to what is technologically feasible given the variable cost of all units in the CAISO control area. This issue is particularly important for the present analysis.

For each hour from June 1, 1998 to December 31, 2000, we compute the average unit-level output for each fossil-fuel generation unit in the California ISO control area from each competitive benchmark price realizations for each of the 100 draws from the joint distribution of unit-level availabilities. The following notation is used:

$\mathbf{OUT\_ACT_{hj}}$ = Actual output in MWh of unit j during hour h,

$\mathbf{OUT\_BBW_{hj}}$ = Mean output in MWh of unit j during hour h from the BBW benchmark pricing procedure, and

$\mathbf{y_{hj}}$ = OUT_ACT_{hj} - OUT_BBW_{hj}.

As shown in Figure 6 of BBW, the actual California market price is set by the intersection of the import supply curve with the aggregate willingness to supply curve of within-control-area fossil fuel generation unit owners. Consequently, under the counterfactual scenario that all within-control-area suppliers behave as if they have no ability to influence the market price through their bidding or scheduling decision, the more aggressive within-control-area bidder (a higher willingness to supply output at the same price) will replace expensive imports. For purposes of computing the competitive benchmark price, BBW assume that the total demand in the CAISO control area is unchanged. Therefore, competitive benchmark pricing substitutes more aggressively supplied within-the-CAISO control area electricity for more expensive imports.

The net result of the assumed price-taking offer behavior of California suppliers under the BBW competitive benchmark pricing simulation is a larger average supply from these fossil-fuel units than the amount actually supplied by these units. That is why the average value y_{hj} is negative.

If suppliers with units located in SCAQMD perceive RTC permit costs as actual production costs we would expect that when RTC permit prices increase those firms with the highest NOx emissions costs – (NOx Emissions Rate)*(NOx Emissions Price) – would operate less frequently. The BBW competitive benchmark pricing process accounts for this fact by specifying that the marginal cost of unit j during day d is equal to

$$\begin{aligned} MC_{jd} = &\ \text{(Variable Operating and Maintenance Costs for Unit j)} \\ &+ \text{(Heat Rate for Unit j in MWh/MMBTU)*(Price of Input Fuel in day d in \$/MMBTU)} \\ &+ \text{(NOx Emissions Rate in lbs of NOx/MWh)*(NOx Emissions Price \$/lb of NOx)} \end{aligned} \tag{4}$$

This expression for marginal cost implies that as the price of RTC permits increases units located in SCAQMD will be dispatched less frequently, because they are more expensive to operate.

The goal of this analysis is to determine the extent to which actual plant operation was consistent with high NOx emission prices increasing the expense of operating units in the SCAQMD region, even though, as noted above, under the BBW competitive benchmark pricing scenario we know that fossil-fuel units located in the California ISO control area, including SCAQMD, would on average have to produce more output during each hour. This is particularly true during hours when prices in California reflect the greatest amount of market power. As shown in Figure 3 of BBW, these tend to be the hours when the amount of energy produced by the fossil fuel units located in the CAISO control area is the greatest.

The specific hypothesis we investigate is whether units owned by suppliers with some or all of their units located in SCAQMD produced more electricity relative to the amount that would be produced under the BBW competitive benchmark pricing assuming NOx emissions costs are actual variable costs of production. We use two approaches to investigate this hypothesis. The first uses only the identity of the unit owner and location of the unit and the second also adds information on the NOx emissions costs of the units.

Introducing our two regressions requires the following additional notation:

$\mathbf{InGen_{hj}}$ = Indicator variable that equals 1 if unit j is owned by a wholesale supplier that has plants in the SCAQMD only

$\mathbf{InOutGen_{hj}}$ = Indicator variable that equals 1 if unit j is owned by a firm that has plants in and outside of SCAQMD and unit is located in SQAQMD

$\mathbf{OutGen_{hj}}$ = Indicator variable that equals 1 if unit is owned by a firm that has plants in and outside of SCAQMD and unit is located out of SCAQMD

$\mathbf{Year(J)_h}$ = Indicator variable that equals 1 if hour h is in year J, for J=1998, 1999, and 2000

$\mathbf{Month(M)_h}$ = Dummy variable that equals 1 if hour h is in month M, M=1,2,...,12

We estimate the following regression for h=1,...,H, where H is the total number of hours from June 1, 1998 to December 31, 2000, and j=1,...,92, the total number of fossil fuel units in California.

$$\begin{aligned} y_{hj} &= \alpha_j + \sum_{J=1999}^{2000} \delta_j Year(J)_h + \sum_{M=2}^{12} \gamma_M Month(M)_h + \sum_{J=1999}^{2000} \eta_j OutGen_{hj} * Year(J)_h \\ &+ \sum_{J=1999}^{2000} \beta_j InGen_{hj} * Year(J)_h + \sum_{J=1999}^{2000} \lambda_j InOutGen_{hj} * Year(J)_h + \varepsilon_{hj} \end{aligned} \quad (5)$$

where α_j is a generation unit fixed effect. Table 7 presents the regression results. We find that relative to 1998, wholesale producers with some or all of the their units in SCAQMD ran their units more intensively relative to the levels predicted by a dispatch based on competitive benchmark pricing in 1999 and 2000 relative to 1998. The coefficients estimates for $INGEN_{hj}$, $INOUTGEN_{hj}$ and $OUTGEN_{hj}$ for 2000 are uniformly about twice the magnitude of the corresponding coefficients for 1999, indicating that these units were run relatively more intensively in 2000.

The results in Table 7 are consistent with the logic that all fossil fuel units owned by suppliers in the CAISO control area with all of their generation units located outside of the SCAQMD region were run less intensively relative to the levels that would occur under competitive benchmark pricing. The units owned by suppliers with some or all of their units located in SCAQMD ran their units more intensively relative to the levels that would occur under competitive benchmark pricing and therefore had a greater likelihood of setting high electricity prices with bids that account for the increased RTC permit prices in 2000.

To investigate whether high perceived NOx costs predicted increased deviations in actual hourly unit-level output from those implied by competitive benchmark pricing including NOx costs, we estimated this same regression including the following additional variables:

$$InGen_{jh}*Year(J)_h*(NOxRate_j*NOxPrice_h) \text{ and}$$

$$InOutGen_{jh}*Year(J)_h*(NOxRate_j*NOxPrice_h),$$

where

$NOxRate_j$ = the rate at which pounds of NO_x emissions are produced per MWh of electricity produced

$NOxPrice_h$ = price of NO_x emissions permits in \$/lb for hour h.

These results are given in Table 8. The coefficients on both of these variables are positive and large relative to their standard errors for 1999 and 2000. This result is consistent with the view that units with higher NOx emissions costs were run more intensively that would be justified based on a least-cost competitive benchmark pricing dispatch that included NOx emission costs as a variable cost of production. We also estimated each of these regressions separately for each year, which prevents us from estimating unit-level fixed effects. These results are given in Table 9 and are largely consistent with the pooled results that include unit-level fixed effects.

The results in Tables 7-9 suggest that fossil fuel unit owners in the CAISO control area distorted their production decisions in order to increase the likelihood that units with high NOx emissions rates would set statewide or zonal market-clearing prices during a larger number of hours of the year during 2000. This is consistent with the discussion in Section 3 of Figure 8 suggesting generation unit owners with some or all of their units located in the SCAQMD region used NOx emission permit prices to enhance their ability to exercise unilateral market power in the California electricity market.

These results suggest that California fossil fuel unit owners withheld supply from low cost units that would be used more intensively under a competitive benchmark pricing dispatch in order to operate units that were thought to have higher operating costs, because they require the purchase of RECLAIM permits to produce electricity. The higher perceived costs for these units allowed suppliers to bid higher prices for electricity supplied from these units. If this bid was accepted, these units would set the price for the entire CAISO control area or, if there was transmission congestion, for the SP15 congestion zone.

4.3. Generation Unit-Level Marginal Costs and NOx Emission Permit Costs

This section provides further evidence in favor of the use of NOx permits as mechanism to raise electricity prices by examining the bidding behavior of the five merchant power producers during the period from June 1 to September 30 for each year from 1998 to 2000. The specific hypothesis we examine is whether or not these firms bid as if their marginal cost of supplying electricity to the CAISO's real-time energy market included RTC emissions permit costs as an actual variable cost similar to input fuel costs.

This is accomplished by applying the procedure described in Wolak (2003a and 2007) for recovering generation unit-level marginal cost functions for facilities that operate in a bid-based short-term wholesale electricity market. We use offers into the CAISO's real-time energy market by the five large fossil fuel suppliers to recover generation unit-level marginal cost functions that are parameterized by input fuel costs and NOx emissions permit costs, where applicable. The bid supply curves into the CAISO's real-time market are submitted at the generation unit-level. These willingness-to-supply curves are step functions with up to ten price steps and quantity increments. Different from the case of Australian National Electricity Market considered in Wolak (2003a and 2007), suppliers can change both their price and quantity offers on an hourly basis.

To construct the first-order conditions for expected profit-maximizing bidding into the CAISO real-time market that will be used to estimate the generation unit-level marginal cost functions for hypothetical Firm A, define the following notation from Wolak (2007). Let

$SA_{ijd}(p,\Theta)$ = amount bid by unit j at price p during hour i of day d,

$SA_{id}(p,\Theta) = \sum_{j=1}^{J} SA_{ijd}(p,\Theta)$ = total amount supplied by Firm A at price p during hour i of day d,

where J is the total number of units owned by Firm A and Θ is the vector of bid parameters for Firm A. For the CAISO real-time market, Θ is a Jx24x10x2 dimensional vector because there are 10 price and quantity increments for each generation unit for every hour of the day for each of the J units owned by Firm A.

Because suppliers in the CAISO real-time market are free to change both their price and quantity offers on an hourly basis, if we assume a constant marginal cost of production for each generation unit, the daily variable profit function of Firm A is the sum of 24 hourly variable profit functions. Let

Q_{id} = real-time demand in hour i of day d,

$SO_{id}(p)$ = amount bid in at price p by all other firms besides Firm A during hour i of day d,

$DR_{id}(p) = Q_{id} - SO_{id}(p)$ = residual demand curve faced by Firm A in hour i of day d at price p,

QS_{jid} = final energy schedule of unit j during hour i of day d,

$QS_{id} = \sum_{j=1}^{J} QS_{ijd}$ = final energy schedule for Firm A during hour i of day d,

C_{jd} = marginal cost of producing output from unit j during day d.

As discussed in BBW, the CAISO is a multi-settlement market meaning that suppliers come into the real-time market with a scheduled output level, for hour i of day d of QS_{id}. The value of $DR_{id}(p)$ is equal to the supplier's total output level.

The realized variable profit function for hour i of day d for Firm A is equal to:

$$\Pi_{id}(\Theta,\varepsilon_i) = (DR_{id}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i)\,p_i(\varepsilon_i,\Theta) - \sum_{j=1}^{J} C_{jd}[SA_{ijd}(p_i(\varepsilon_i,\Theta),\Theta)], \tag{6}$$

where $p_i(\varepsilon_i,\Theta)$ is the solution in p to the following equation $DR_{id}(p,\varepsilon_i) = SA_{id}(p,\Theta)$, which the price where the realized residual demand curve and the bid curve of Firm A intersect. As discussed in Wolak (2003a and 2007), Firm A faces several sources of uncertainty in the realized residual demand curve that it might face when it bids into the real-time market. For hour i, this uncertainty is represented by the random variable ε_i.

Following the notation in Wolak (2007), let

p_{ijk} = the bid price for increment k of unit j during hour i for Firm A

q_{ijk} = the bid quantity for increment k of unit j during hour i for Firm A.

In terms of this notation $\Theta = (p_{ijk}$, i=1,2…,24, j=1,…,J, k=1,2,…,10, q_{ijk}, i=1,2…,24, j=1,…,J, k=1,2,…,10). As discussed in Wolak (2007), if the offer price for a bid increment k of unit j for hour i is strictly below the offer cap and above the offer floor, then we know that if the firm maximizes expected profits, the following first-order condition should hold for p_{ijk}:

$$\frac{\partial E_{\varepsilon}[\Pi_{id}(\Theta,\varepsilon)]}{\partial p_{ijk}} = 0\,, \tag{7}$$

Where $E_{\varepsilon}(.)$ denotes the expectation with respect to the distribution of ε. We can follow the same procedure as described in Wolak (2003a and 2007) to construct a differentiable realized variable profit function. Let $\Pi^{h}_{id}(\Theta,\varepsilon)$ denote the differential realized variable profit function parameterized by the smoothing parameter h, as described in Wolak (2003a and 2007). This quantity can be written in terms of the smoothed residual demand curve and smoothed unit-level bid supply curves defined in Wolak (2003a and 2007) as:

$$\Pi^{h}_{id}(\Theta,\varepsilon_i) = (DR^{h}_{id}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i)\,p_i(\varepsilon_i,\Theta) - \sum_{j=1}^{J} C_{jd}[SA^{h}_{ijd}(p_i(\varepsilon_i,\Theta),\Theta)]\,. \tag{8}$$

The derivative of the smoothed variable profit function with respect to p_{ijk} is equal to:

$$\frac{\partial \Pi^{h}_{id}(\Theta,\varepsilon)}{\partial p_{ijk}} = \{(DR^{h}_{id}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i) + p_i(\varepsilon_i,\Theta)\frac{dDR^{h}_{id}(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{dp} \tag{9}$$

$$-\sum_{j=1}^{J} C_{jd}[\frac{SA^{h}_{ijd}(p_i(\varepsilon_i,\Theta),\Theta)}{dp}]\}\frac{\partial p^{h}_{i}(\varepsilon_i,\Theta)}{\partial p_{ijk}} - \sum_{j=1}^{J} C_{jd}\frac{SA^{h}_{ijd}(p_i(\varepsilon_i,\Theta),\Theta)}{dp_{ijk}}\,,$$

where $\frac{\partial p^{h}_{i}(\varepsilon_i,\Theta)}{\partial p_{ijk}}$ is computed as described in Wolak (2003a and 2007). To estimate the parameters of the marginal cost function for unit j during day d, C_{jd}, we use the derivative of the smoothed variable profit function for Firm A for all price increments that are strictly less than the relevant offer cap and offer floor on the CAISO real-time market for all units during all hours of the day. Specifically we construct the following moment condition for each hour i of the day for Firm A.

$$m_{id}(\beta) = I(uncon_{id})\sum_{j=1}^{J}\sum_{k=1}^{K} I(p_{\max} > p_{ijk} > p_{\min})\frac{\partial \Pi_{id}^{h}(\Theta,\varepsilon)}{\partial p_{ijk}}, \tag{10}$$

where $I(p_{\max} > p_{ijk} > p_{\min})$ is an indicator function for the event that p_{ijk} is strictly above p_{min}, the floor on price bids, and strictly below p_{max}, the cap on price bids, $I(uncon_{id})$ is an indicator variable that equals 1 there is a single price of energy for the entire CAISO control area and β is the vector of parameters of the unit-level marginal cost function. We restrict our analysis to uncongested hours, $I(uncon_{id}) = 1$, because this simplifies the construction of the first-order conditions for firms with units in multiple congestion zones. This should only reduce the precision of our parameter estimates relative to the case that included all hours in the sample.

We assume the following functional form for C_{jd}, the marginal cost of unit j on day d, in terms of the product of unit j's heat rate and the price of natural gas and unit j's NOx emission rate and the price of RTC permits for units located in the SCAQMD region:

$$\begin{aligned} C_{jd} &= \beta_0 + \sum_{m=1}^{4}\beta_m Firm(m,j) + \sum_{m=5}^{9}\beta_m HR(m,j) * Gas_d * Firm(m,j) \\ &+ \sum_{m=10}^{12}\beta_m NOXR(m,j) * NOXP_d * Firm(m,j) + \eta_{jd} \end{aligned} \tag{11}$$

where the variables are defined as follows:

FIRM(m,j) = indicator variable equal to 1 if j equals m and zero otherwise

HR(m,j) = the heat rate in MMBTU/MWh of unit j owned by firm m

GAS_d = price of natural gas in day d

NOxRATE(m,j) = the NOx emissions of unit j owned by supplier m

$NOxPRICE_d$ = RTC NOx emissions permit price for day d

We use the daily unit-level natural gas price series and the transaction volume-weighted average NOx emissions permit price series used in BBW to compute the GAS_d and $NOxPRICE_d$. Figure 11 plots this NOx emissions price series.

To estimate the elements of β, we construct the following vector of moment restrictions. For each of the five suppliers we stack the values of $m_{id}(\beta)$, i=1,2,…24, for each day d, into a vector. Let $M_d(\beta)$ denote the 120-dimensional vector of moments for all 24 hours of day for each of the 5 large fossil fuel suppliers in the CAISO control area. We estimate β using the smoothed Generalized Method Moments (GMM) procedure described in Wolak (2003a and 2007). Under the null hypothesis that the five suppliers bid to maximize the expected value of their hourly profits from selling in the CAISO's real-time energy market treating both input fuel costs and RTC emission permit costs as variable costs of production, the true values of the β_m (k=5,..,9) should be 1 and the true values of the β_m (k=10,11,12) should be 1. There are only three suppliers with potentially non-zero coefficients associated with NOx emission costs because only three of the five large fossil-fuel generation unit owners had plants located in the SCAQMD region. They were AES/William, Dynegy, and Reliant. The other two large generation unit owners, Duke and Mirant, only owned units outside of the SCAQMD region.

Table 10 presents the results of estimating equation (11) over our sample period of June 1 to September 30 of 1998, 1999 and 2000. The standard errors are computed as discussed in Wolak (2003a and 2007). The test statistic for the null hypothesis of expected profit-maximizing bidding behavior presented in Wolak (2003a and 2007) is 124.23. This statistic is asymptotically distributed as a χ^2_{N-P} random variable under the null hypothesis, where N = 120 is the number of moment restrictions and P = 13 is the number of parameters estimated, which implies that the null hypothesis of unilateral expected profit-maximizing behavior cannot be rejected.

Table 10 shows that for the case of fuel costs, the point estimates of the all of the β_m (k=5,..,9) are not statistically significantly different from 1. Specifically, the size $\alpha = .05$ Wald test of the joint null hypothesis H: β_k=1 for (i=5,...,9) cannot be rejected. Substantially different results are obtained for NOx emission permit costs. The size $\alpha = .05$ Wald test of the joint null hypothesis that H: β_m=1 for (i=10,11,12) can be rejected. Moreover, the point estimates of these three parameters are significantly less than one. Because all of the results are qualitatively similar across the β_m (m=5,…,9) and three values of β_m, (m=10,11,12) we only report estimates by the firm number, and not the firm name. To preserve anonymity, the numbers used for fuel costs do not correspond to the numbers used for NOx emissions permit costs. The bottom of portion of this table presents the results estimating this model assuming all of the β_m (m=5,…,9) and β_m (m=10,11,12) are equal. These results further confirm our conclusion that fuel costs enter the generation unit-level marginal cost function with a coefficient of 1 and NOx emission costs enter with a coefficient significantly less than one.

We believe the results in Table 10 provide strong evidence that NOx emissions permit costs were not treated in the same manner as input fuel costs in determining the supplier's variable costs used to compute their expected profit-maximizing bidding strategy into the CAISO's real-time market. Combined with the evidence presented in Sections 4.1 and 4.2, these results suggest that NOx emissions permit prices were used to justify higher bids into the California electricity market, but were not treated as actual costs of production on equal footing with input fuel costs. The deviations in hourly plant operation behavior relative to the competitive benchmark Section 4.2 suggests that unit owners were successful at raising wholesale electricity prices by bidding high prices from units located in the SCAQMD region during 2000. These units ran more frequently than would be predicted by competitive benchmark dispatch in 2000. Moreover, as NOx emission price rose, these units were dispatched for even more electricity relative to what would occur under a competitive benchmark pricing dispatch treating NOx emissions costs as a production cost.

5. Conclusions and Directions for Future Research

Taken together, our results suggest that NOx emissions permit prices were used by suppliers during the last six months of 2000 and early 2001 to enhance their ability to exercise market power in the California electricity market. The evidence presented on the NOx emissions permit purchase prices, unused permit holdings, generation unit operating decisions, and the bidding behavior of suppliers in the CAISO's real-time market are all consistent with the view that the prices of RECLAIM permits were used to justify higher bid prices into California's electricity market. These higher bid prices are also consistent with the greater ability suppliers had to exercise unilateral market power in CAISO real-time market during the last six months of 2000 documented in Wolak (2003b).

Although our paper focuses on the interaction of the RECLAIM market with the California electricity market in unique period of market and political turmoil, we believe our results have implications for other emissions permit markets. Perhaps the most relevant application for our findings is the introduction of greenhouse gas (GHG) emissions permit trading to address climate change. Although fossil-fuel generation unit owners produce a fraction of worldwide GHG emissions, they are likely to be early and substantial participants in any GHG emissions permit trading scheme. For example, the European Emissions Trading Scheme Directive established a market for tradable GHG emissions permits. While electricity generators comprise only 20 percent of overall carbon emissions in this market area they represent more than 50 percent of the emissions covered by the market (Linares, et al., 2006). Linares, et. al. (2006) argue high GMG emissions rate generators with the ability to exercise unilateral market power in the wholesale electricity market are likely to more frequently set market wide prices. For this reason, as increases in permit prices are likely to increase electricity prices significantly.

The behavior we document here also underscores the need for transparency in emissions permit markets. This is fundamental to the efficient operation of an emissions permit market but clearly has implications for downstream product markets where firms have the ability to exercise unilateral market power. In particular, the emissions permit market design process should focus on creating conditions for uniformity in permit prices across all types of market actors. One aspect of the RECLAIM market that facilitated the use of RTCs to raise wholesale electricity prices was the paid-as bid nature of transactions. This model allowed suppliers interested in raising RECLAIM transactions prices to do so without impacting the prices paid by other RTC buyers wanting to keep their purchase prices down. The enormous increase in the standard deviation of transactions prices for 2000 and 2001 vintage permits during 2000 is evidence in favor of this design flaw in the RECLAIM market. This experience argues in favor of periodic trading of RTC permits (with anonymity for buyers and sellers) using a market-clearing price mechanism.

The evidence for strategic use of emissions permits also bears on the debate over the appropriate methodology for allocating emissions rights. A complete answer to this question facing policymakers is beyond the scope of this paper. However, we note that if permits are not only valuable as a right to emit but also potentially as a mechanism to exert unilateral market power in the downstream product market they are even more valuable and, thus, the magnitude of the transfer from consumers to producers when emissions rights are allocated without a price has the potential to be very large. An appropriately designed and administered uniform-price auction has the potential to reduce the ability of market actors to use permits to raise downstream prices if bids in the auction reflect these expected profits.

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Table 1: NOx Emission Price Prediction Based Given Buyer Characteristics

Dependent Variable = Natural Logarithm of Transaction Price for RTC NOx Emissions Permit		
Variable	Parameter Estimate	Standard Error
Intercept	-1.378	0.044
Wholesale*AQMD	0.099	0.111
Wholesale*InOut	0.104	0.107
Wholesale*Out	0.230	0.280
Utility	-0.437	0.059
Year98	0.489	0.057
Year99	1.097	0.054
Year00	2.171	0.054
Year01	2.281	0.057
Wholesale*AQMD*Year00	0.172	0.136
Wholesale*AQMD*Year01	0.310	0.144
Wholesale*InOut*Year00	0.271	0.120
Wholesale*InOut*Year01	0.298	0.129
Wholesale*Out*Year01	0.091	0.376
Utility*Year00	-0.149	0.092
Utility*Year01	-0.203	0.096
Number of Observations = 1,792		R^2 = 0.71

Table 2: NOx Emission Price Prediction Based Given Buyer Characteristics and Transactions Date

Dependent Variable = Natural Logarithm of Transaction Price for RTC NOx Emissions Permit		
Variable	Parameter Estimate	Standard Error
Intercept	-1.407	0.066
Wholesale*AQMD	-0.036	0.076
Wholesale*InOut	-0.018	0.074
Wholesale*Out	0.017	0.192
Year98	0.347	0.043
Year99	0.696	0.043
Year00	1.264	0.045
Year01	1.286	0.046
TransYear95	0.313	0.077
TransYear96	0.010	0.077
TransYear97	-0.093	0.067
TransYear98	0.176	0.064
TransYear99	0.314	0.064
TransYear00	1.031	0.063
TransYear01	1.501	0.065
Wholesale*AQMD*Year00	0.115	0.093
Wholesale*AQMD*Year01	0.126	0.099
Wholesale*InOut*Year00	0.211	0.082
Wholesale*InOut*Year01	0.250	0.089
Wholesale*Out*Year01	0.015	0.258
Utility*Year00	0.130	0.063
Utility*Year01	0.035	0.066
Utility	-0.028	0.040
Number of Observations = 1,792		R^2 = 0.87

Table 3: Average Difference Between Broker Purchase Price and Sale Price for RTCs

RTC Vintage	1997	1998	1999	2000	2001
Non Generation Buyer	-$0.02	-$0.12	-$0.21	-$12.77	-$5.52
Inout Generator Buyer		-$0.15	$0.05	$2.05	$14.54
AQMD Generator Buyer			$0.23	-$4.95	$11.87

Table 4: Number of Unused RTCs by Market Participant Type

	Generator 1	**Generator 2**	**Generator 3**	**LADWP**	**Other Generators**	**Traders**
1997	14,665		N/A	702,465	20,924	311,213
1998	283,408	10,004	80,228	750	13,558	93,270
1999	448,354	0	0	14,817	5,096	62,327
2000	472	3,490	0	9,623	908	98,396

Table 5: Share of Unused RTCs Given Buyer Characteristics and Transactions Date

Dependent Variable = Share of Market Wide Unused RTC NOx Emissions Permits		
Variable	Parameter Estimate	Standard Error
Cycle2*Year98	-0.004	0.002
Cycle2*Year99	0.001	0.003
Cycle2*Year00	-0.004	0.002
Year99	-0.008	0.002
Year00	-0.002	0.002
[Cycle2*Year99+Year00]*Raise	0.025	0.007
Number of Observations = 1,634		R2 = 0.48

Table 6: Share of Unused RTCs Given Buyer Characteristics and Transactions Date Separating Cycle 2 1999 and 2000

Dependent Variable = Share of Market Wide Unused RTC NOx Emissions Permits		
Variable	Parameter Estimate	Standard Error
Cycle2*Year98	-0.004	0.002
Cycle2*Year99	0.001	0.003
Cycle2*Year00	-0.004	0.002
Year99	-0.008	0.002
Year00	-0.001	0.001
Cycle2*Year99*Raise	0.028	0.009
Year00*Raise	0.022	0.008
Number of Observations = 1,634		$R2 = 0.48$

Table 7: Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Variable	Parameter Estimate	Standard Error
OutGen*Year99	23.656	0.463
OutGen*Year00	47.058	0.446
InGen*Year99	19.215	0.478
InGen*Year00	56.034	0.46
InOutGen*Year99	35.032	0.593
InOutGen*Year00	66.69	0.571
Number of Observations = $2{,}29 \times 10^6$		$R^2 = 0.319$

*Regression includes generation unit-level, monthly, and yearly dummy variables.

Table 8: Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics, NOx Emissions Rate, and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Variable	Parameter Estimate	Standard Error
OutGen*Year99	23.656	0.436
OutGen*Year00	47.058	0.446
InGen*Year99	13.192	0.552
InGen*Year00	54.595	0.482
InOutGen*Year99	33.12	0.678
InOutGen*Year00	65.905	0.604
InGen*Year99*NOxPrice*NOxRate	5.615	0.254
InGen*Year00*NOxPrice*NOxRate	0.058	0.006
InOutGen*Year99*NOxPrice*NOxRate	2.583	0.464
InOutGen*Year00*NOxPrice*NOxRate	0.038	0.009
Number of Observations = $2{,}29 \times 10^6$		$R^2 = 0.320$

*Regression includes generation unit-level, monthly, and yearly dummy variables.

Table 9: By Year Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics, NOx Emissions Rate, and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Year 1998–Table 4 Results (N= 472,603, R^2= 0.0240)		
Variable	Parameter Estimate	Standard Error
OutGen	-51.067	0.478
InGen	-21.462	0.493
InOutGen	-26.022	0.612
Year 1998–Table 4 Results (N= 472,603, R^2= 0.0244)		
OutGen	-51.067	0.478
InGen	-23.802	0.540
InOutGen	-28.460	0.665
InGen*NOxPrice*NOxRate	3.489	0.327
InOutGen*NOxPrice*NOxRate	5.626	0.601
Year 1999–Table 4 Results (N= 805,919, R^2= 0.0120)		
Variable	Parameter Estimate	Standard Error
OutGen	-27.411	0.332
InGen	-2.247	0.342
InOutGen	9.009	0.425
Year 1999–Table 5 Results (N= 805,919, R^2= 0.0127)		
Variable	Parameter Estimate	Standard Error
OutGen	-27.411	0.332
InGen	-8.183	0.430
InOutGen	7.083	0.527
InGen*NOxPrice*NOxRate	5.533	0.243
InOutGen*NOxPrice*NOxRate	2.716	0.440
Year 2000–Table 4 Results (N= 1.101×10^6, R^2= 0.0266)		
Variable	Parameter Estimate	Standard Error
OutGen	-4.009	0.294
InGen	34.571	0.303
InOutGen	40.668	0.376
Year 2000–Table 5 Results (N= 1.101×10^6, R^2= 0.0267)		
Variable	Parameter Estimate	Standard Error
OutGen	-4.009	0.294
InGen	33.172	0.337
InOutGen	39.819	0.426
InGen*NOxPrice*NOxRate	0.056	0.006
InOutGen*NOxPrice*NOxRate	0.041	0.010

*All regressions include monthly dummy variables.

Table 10: Unit-Level Marginal Cost Functions Given
Fuel Costs and NOx Emissions Rate Costs

Generation Unit Level Marginal Cost Function for Unit j in Hour i (Derived from Assumption of Expected Profit-Maximizing Bidding Behavior)		
Variable	Parameter Estimate	Standard Error
Intercept	4.290	0.922
Firm2	1.493	0.204
Firm3	0.502	0.203
Firm4	-0.332	0.189
Firm5	-0.123.	0.232
Gas*HR1	0.944	0.062
Gas*HR2	0.871	0.076
Gas*HR3	0.935	0.042
Gas*HR4	1.012	0.049
Gas*HR5	0.893	0.084
NOxPrice*NOxRate1	0.347	0.113
NOxPrice*NOxRate2	0.319	0.115
NOxPrice*NOxRate3	0.292	0.132
Estimation Constraining All Gas*HR and NOxPrice*NOxRate Coefficients To Be Equal		
Intercept	4.106	0.198
Firm2	1.323	0.232
Firm3	0.631	0.198
Firm4	-0.408	0.212
Firm5	-0.082	0.282
Gas	0.972	0.041
NOxPrice*NOxRate	0.344	0.083

Figure 1: South Coast Air Quality Management District Region

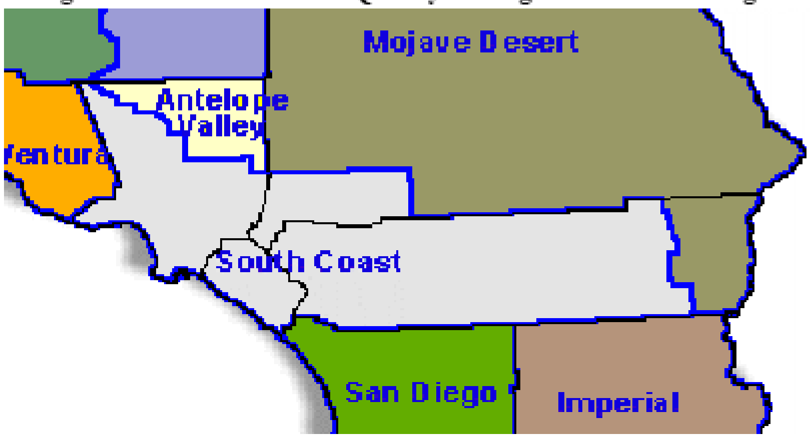

Figure 2: Total RTC Supply and Reported Emissions

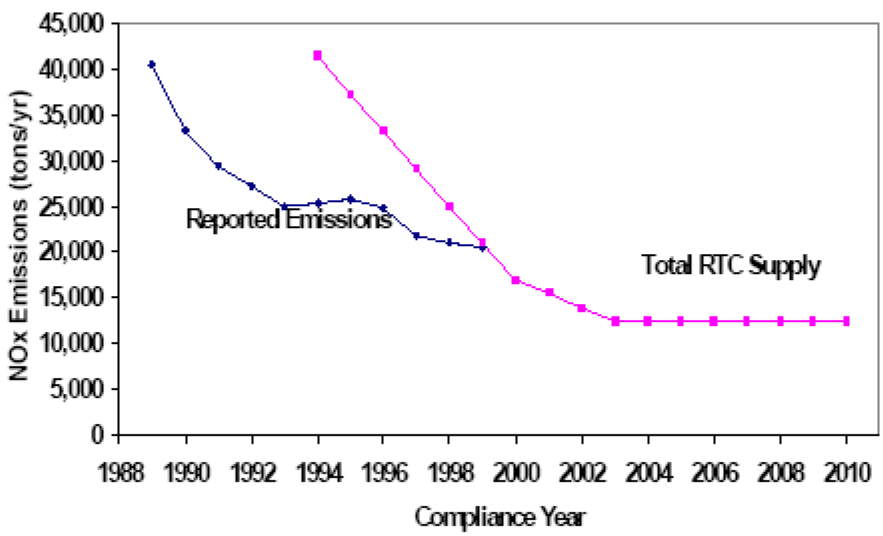

Figure 3: Mean RTC Price for 2000 and 2001 Vintages

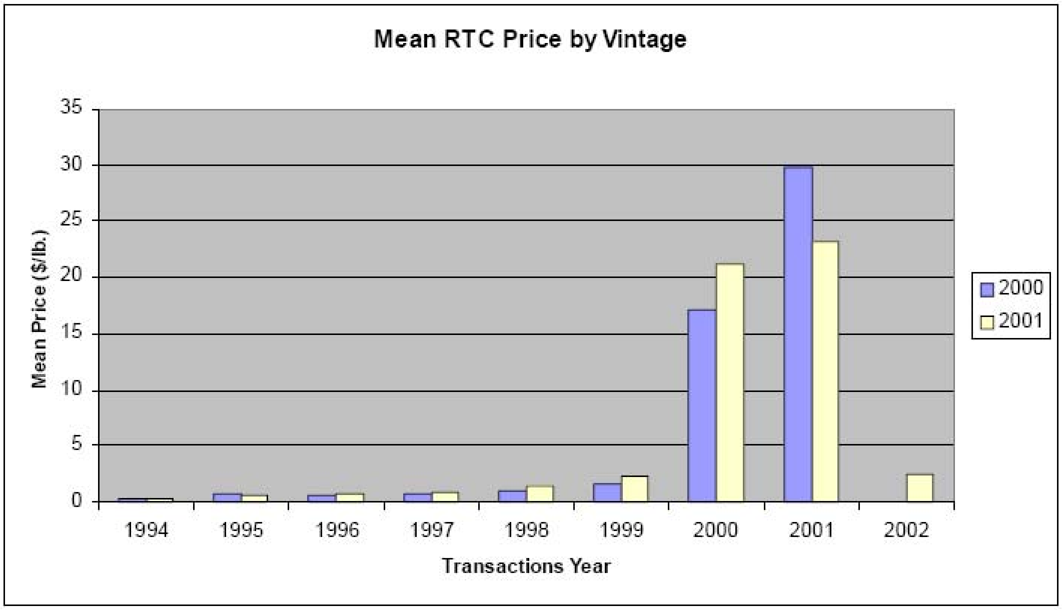

Figure 4: Transaction Volume Weighted Average Prices by Vintage

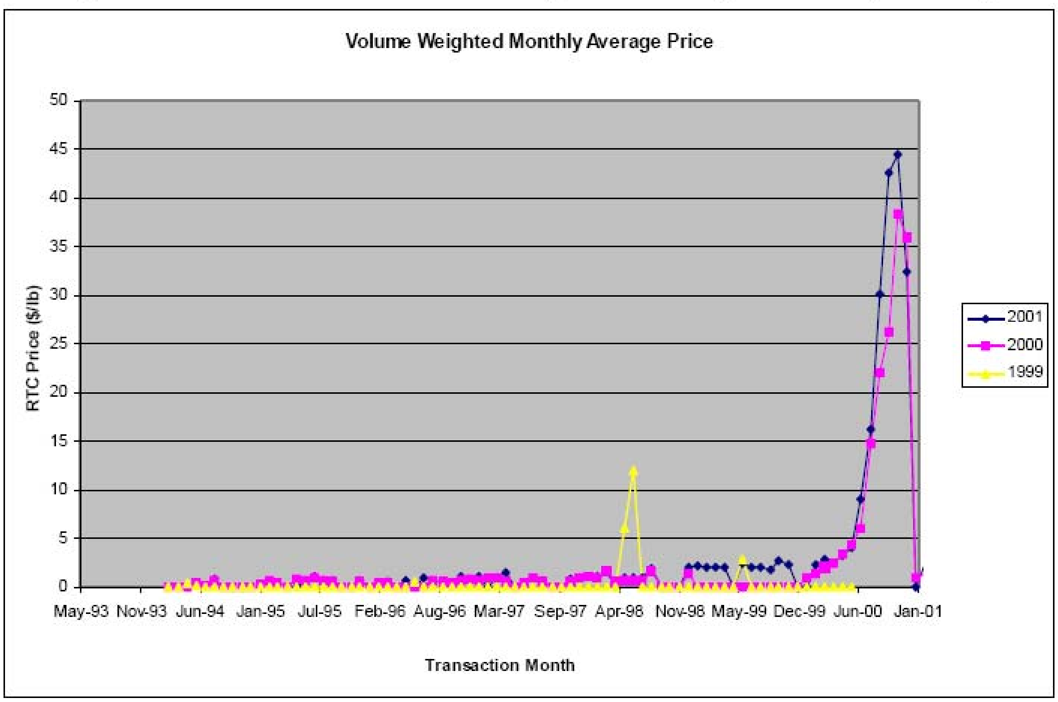

Figure 5: Annual Standard Deviation of Transactions Prices by Vintage

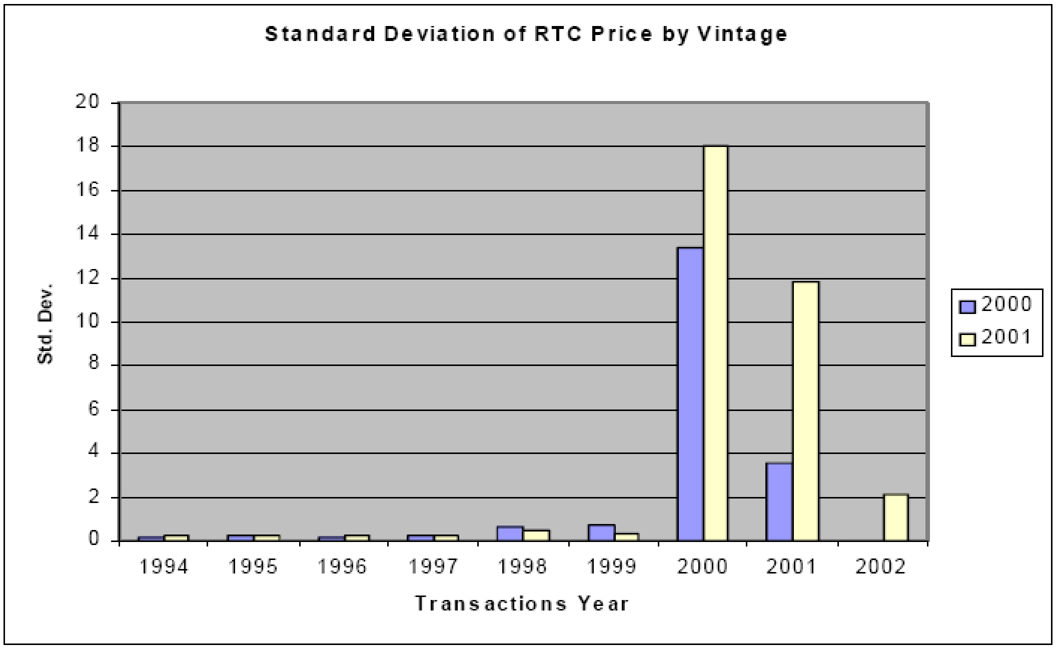

Figure 6: Average Transaction Volume by Vintage

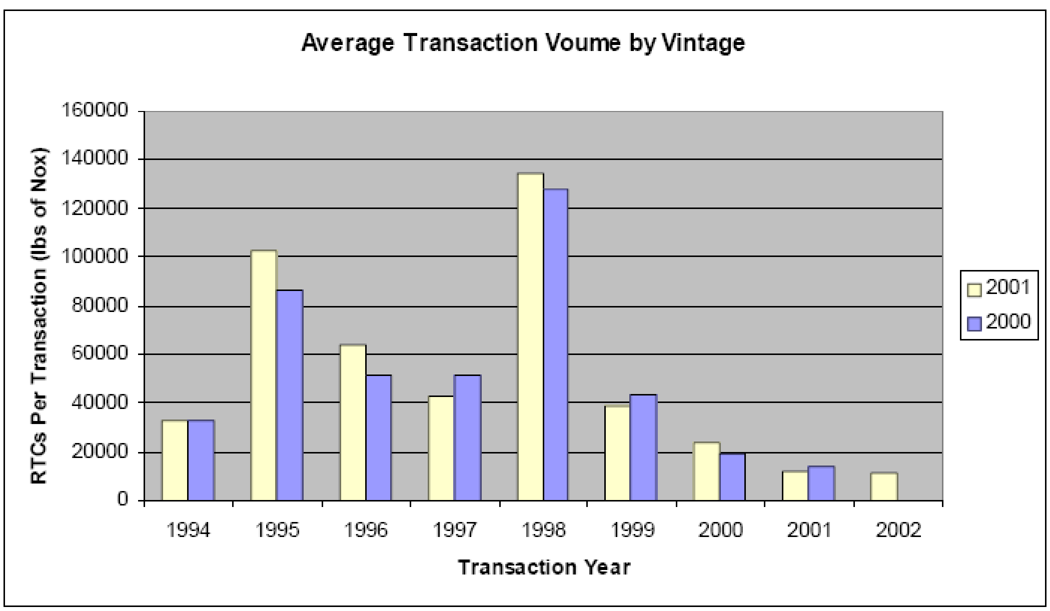

Figure 7: Total Number of Transactions Annually by Vintage

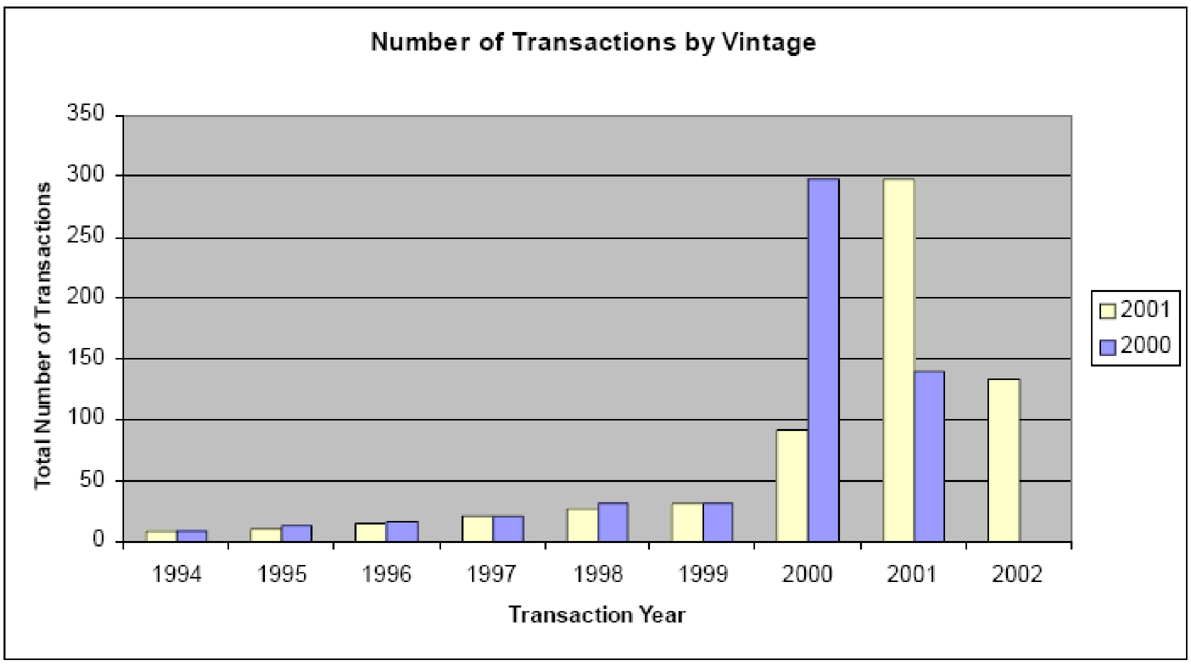

Figure 8: Using NOx Permit Prices to Raise Wholesale Electricity Prices

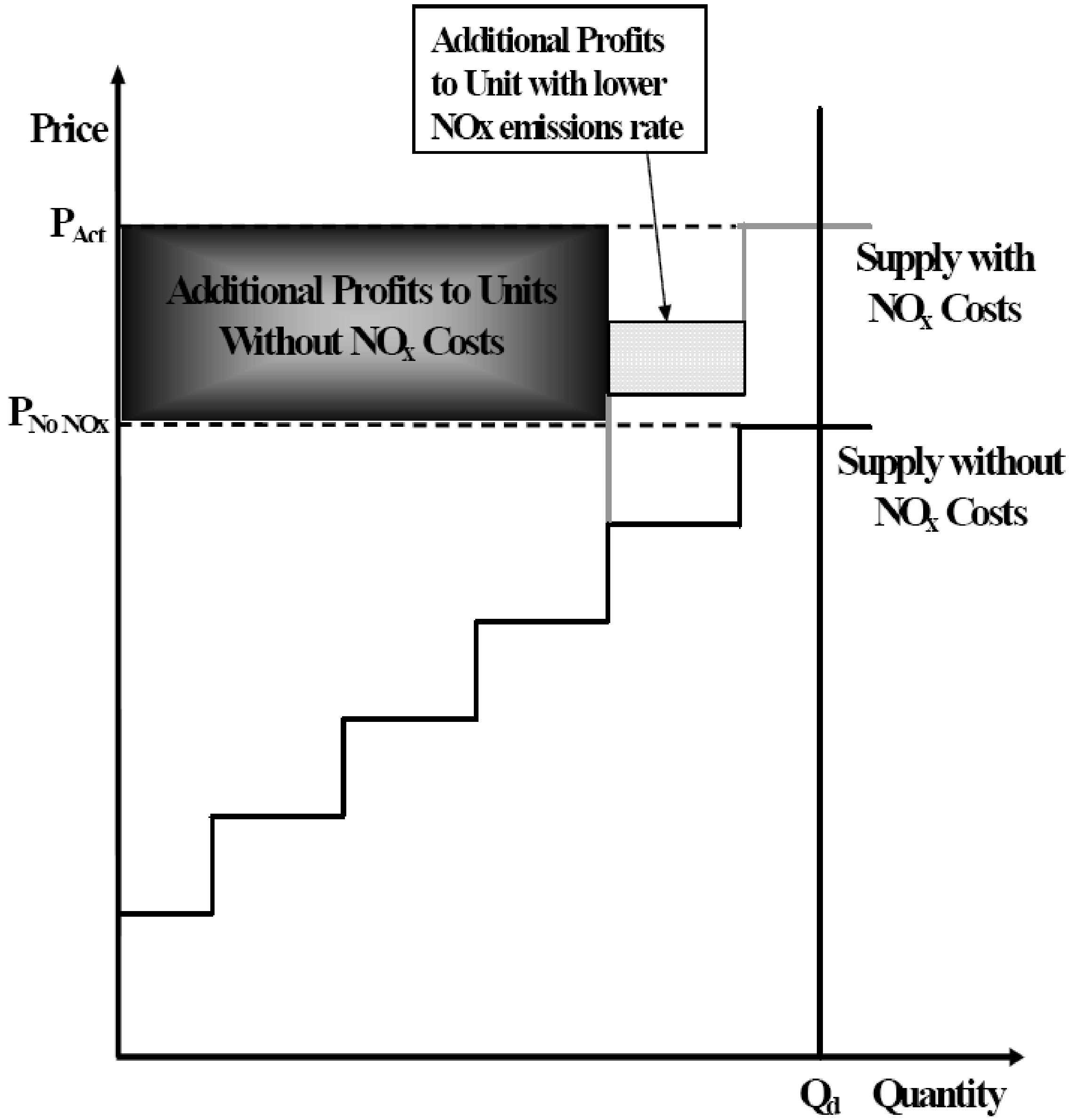

Figure 9: Cummulative Distribution of NOx Emission Rates in SCAQMD

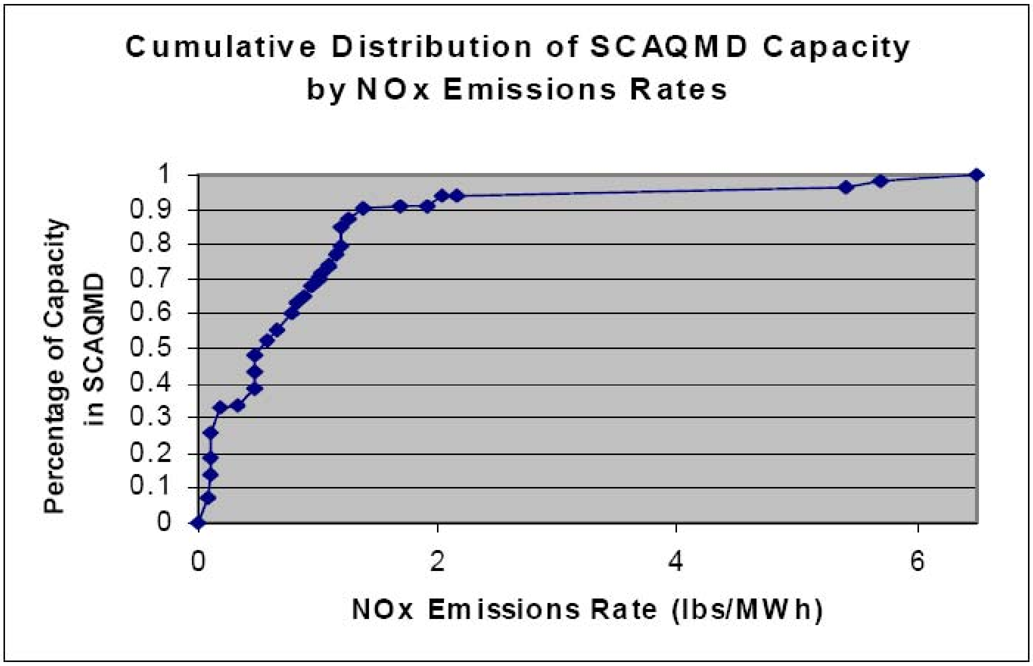

Figure 10: Monthly Average Real-Time Prices by Congestion Zone

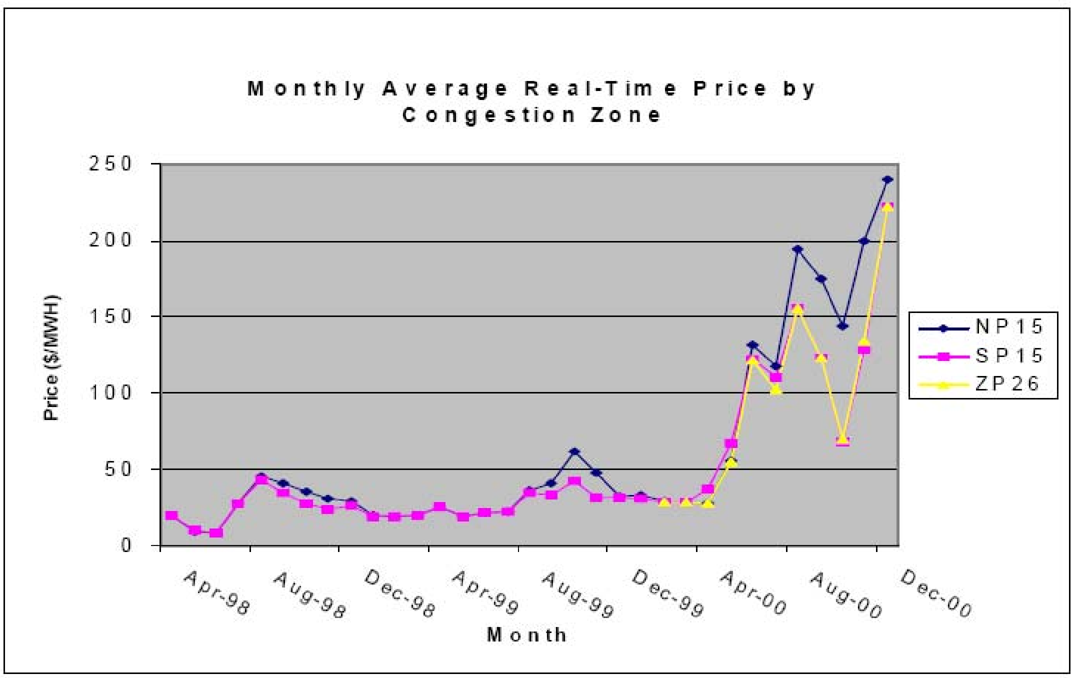

Figure 11: Monthly Average NOx Emission Prices Used in BBW (2002)