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Abstract

Regulators of electricity markets around the world continue to struggle with the problem of incentivizing generators whose output, due to their location in the grid, has no viable substitutes. Such generators possess 'local' market power. Since these generators also compete in broader regional markets, the actions taken to exploit their local market power can also effect market outcomes over larger areas. In California, a contract structure known as the reliability must-run (RMR) contract was developed to address the problem of local market power. However, the contract form that was in place during 1998 created serious incentive problems. We find that, during the months of June through September 1998, RMR contracts had the effect of raising overall supply bid prices from most producers, thereby leading to higher energy prices in the California regional market.

1 Introduction

The electricity sectors of many countries are undergoing a transition from either state-ownership or regulated franchise monopoly to an organization that is more market-oriented. Despite the general move to market-based pricing, regulators of electricity markets around the world continue to struggle with the problem of incentivizing generators whose output, due to their location in the grid, has no viable substitutes. Such generators possess 'local' monopoly power, and in deregulated settings have frequently been able to extract significant rents from their advantageous locations within a power

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system. Since strategically located generators also simultaneously compete in broader regional markets, the actions taken to exploit local market power can also effect market outcomes over larger areas. Similarly, regulatory mechanisms intended to mitigate local market power can also effect competition far beyond the geographic scope of their control.

In California, a contract structure known as the reliability must-run (RMR) contract was developed to address the problem of local market power. However, the contract form that was in place during 1998 created serious incentive problems. The most common contract during this period, known as contract A, paid generators a portion of their sunk and fixed costs, in addition to their operating costs, for each unit of power produced. The payment structure of the RMR contracts was such that must-run generators received these lucrative payments only if they were not already committed to producing power through the regional market process. These payments created a clear and often significant opportunity cost to participating in the regional market. In other words, a generator that competed aggressively in the regional market was unlikely to receive RMR contract revenues, which were often well above those that could be obtained from the resulting regional market prices.

In this paper, we examine the impact of these contract payments on the bidding behavior of market participants. We find that, during the months of June through September 1998, A type RMR contracts had the effect of raising overall supply bid prices from most producers, thereby leading to higher energy prices in the California regional market. In this sense, a regulatory mechanism, the RMR contract, promoted the leveraging of the local market power of certain producers onto the broader wholesale electricity market.

The case of RMR contracts in California is an example of the interaction of sequential markets for the same commodity, where market rules in one market impact prices in all markets. The California electricity market features an hourly day-ahead market, which is in effect a forward financial market, and an hourly real-time physical spot market in which supply and demand are continuously balanced. Because must-run contracts are invoked during the period between the close of the day-ahead market and the operation of the spot market, one might think that the bidding incentives provided by these contracts should not impact suppliers other markets. However, by impacting the dynamic interaction between the day-ahead forward market and the spot market, RMR contracts appear to have affected the prices in both the spot and forward markets.

In Section 2, we discuss the problem of local market power in the context of deregulated electricity markets in general, and the California market in particular. In Section 3, we describe the RMR contract mechanisms that were developed in order to deal with this problem in California and discuss the counter-productive (to market efficiency) incentives that these contracts provided to suppliers. We also present some summary data that illustrates these incentive issues.

In Section 4 we estimate the impact of these contract incentives on the bid functions of both suppliers and consumers in the California Power Exchange (PX), the day-ahead energy market, using participant-level bid data from the months of June to September of 1998. Using changes in the hourly amount of energy called under RMR contracts and relating these to changes in generator bid functions controlling for other factors likely to impact generator bidding behavior, we recover an estimate of each participant's hourly bid curve as a function the expected amount of RMR contract calls from its generating units and those of its competitors. Using this methodology, we estimate that PX prices were on average 15 percent higher during these months as result of the existence of these RMR contracts.

In Section 5, we examine the impact of the incentive effects of RMR contracts on transactions occurring outside of the PX, particularly on transactions in the real-time spot market. We conclude the paper with a discussion of the revised RMR contracts currently in place in the California market.

2 Spatial Competition and Local Market Power in Electricity Markets

A significant contributor to the worldwide momentum towards competitive restructuring of electricity markets has been the perception that the generation sector of this industry no longer constitutes a natural monopoly. While competition for the generation of electricity may indeed be robust over large regions, the limits of transmission capabilities in most electric systems combined with the lack of means to economically store electricity often limit the scope of competition to relatively small geographic areas. Within these smaller areas, individual generation units can possess significant market power. This market power is exacerbated by the fact that the real-time demand for wholesale electricity is extremely price-inelastic.

The geographic scope of electricity markets are continually changing. During low demand periods transmission congestion can be minimal and supply can come from a variety of locations. During peak demand periods, transmission and reliability constraints can effectively segment markets into many sub-regions. Importantly, the suppliers themselves have the ability to influence the extent of spatial competition. By withholding output or raising prices, for example, generators in importing regions can force an increase in imports to the point that transmission constraints become binding, thereby fragmenting the market.[1] The opportunities and complexities of such strategies become more pronounced when one considers the physical aspects of power flows in meshed network and

[1]This is an important contrast to markets where there are no binding constraints on transportation capacity. See Borenstein, Bushnell, and Stoft (1996).

the incentive impact of transmission rights.[2]

The existence of local market power means that the designers of electricity markets must choose from a limited set of unsatisfactory choices. If a single, market-wide price is determined through an open market process that ignored transmission constraints and localized needs, some critical generation units may be left out of the proposed dispatch if the market price (ignoring local needs) were below their operating costs. However, if prices for the supply of power from such 'must-run' units are instead determined through a market process held at every location in the network, these local generators could dictate prices to their captive customers.

In some markets, such as New Zealand's and the Pennsylvania, New Jersey, and Maryland (PJM) pool, prices are set at hundreds of different locations, or 'nodes,' within the network.[3] Prices vary in a way that reflects the marginal impact of supply on network operating constraints, which can differ by location. Power injected into the network in an area that relives congestion will receive a higher price than power injected into an area that creates additional congestion. In general, power is more expensive in the areas in which import constraints are binding, although the complexities of power flows can sometimes lead to less intuitive outcomes.

In other markets, such as those in England and Wales (E&W), Scandanavia, and California, prices are determined for a relatively small number of 'zones' covering broad regions.[4] In the case of E&W, only a single, nationwide energy price is determined by intersecting aggregate supply offers with a forecast of demand. Network operating costs are lumped into an 'uplift' charge and spread evenly over all users. This 'blending' of locational energy prices really only applies to consumers, however. If the output of a generation unit in the E&W pool is needed to relieve transmission constraints, and yet has an offer price that is above the national market-clearing price, it is allowed to be 'constrained-on' and to earn its offer price, irregardless of what other generators are earning. Similar arrangements are made in the Nord Pool for must-run generators whose bid prices exceed their regional 'zonal' price.[5]

In both kinds of markets, those with a large number of nodal prices and those with only a few zonal prices, strategically located generators can profit from network constraints by raising their offer prices. The existence of transmission constraints means that these generators face less potential competition than those located elsewhere in the network. In the absence of substitutes for the output of these units, the market must either raise the locational price of energy (in the case of New Zealand), or make an above-market payment

[2]See Cardell, Hitt and Hogan (1997), and Joskow and Tirole (1999a) and (1999b).

[3]Wolak (1997)provides an overview of the organization of the major electricity markets operating around the world.

[4]In describing electricity markets, the term 'nodal' pricing is conventionally used to describe markets with a high resolution of locational energy prices, while 'zonal' pricing is used to describe markets with far fewer locational prices. We adopt these conventions for the purposes of this discussion.

[5]See Johnson, Verma, and Wolfram (1999)

to the generator (in the case of England & Wales). Such generators are disproportionately able to affect prices, at least in their local areas. During the early years of operation of the E&W, for example, strategically located generators learned to adjust their bids to take advantage of their constrained-on status, causing a year-to-year increase in constrained-on payments of over £70 million. Supply bids from these units appear to have been limited primarily by a fear of regulatory intervention.[6]

The supply and demand conditions leading to such a local market power problem are illustrated in Figure 1. While there are many generators in the 'south' there is only one located in the 'north.' Transmission constraints prevent all the demand in the north from being supplied by units located in the south. One option is to set prices at two locations. However, because there is only one generator able to meet demand at the north location, this generator would enjoy monopoly power over this segment of the market. A second option is to aggregate all supply and demand into a system-wide market. When all suppliers and consumers are aggregated together, however, the market-clearing price of P_1 is not sufficient to compensate the must-run unit for its operating costs. The only remaining option is to compensate the northern generator at some level that does not depend upon the system-wide price, but also does not allow that generator to set a 'market' price in the north. This is essentially what is done with 'constrained-on' payments in England & Wales and with reliability must-run contract payments in California.

However, the potential to earn special compensation can often influence bidder behavior. An extremely high offer price from a strategically located producer could separate that producer's market from others, thereby giving this generator a lucrative payment, but over a relatively small amount of output. This is the revenue a generator earns if it is too expensive for the general market. In other words, if a firm bids a price for its strategically located unit that is too high to compete with generators from other locations, the firm still earns its bid price for at least the local demand. If there were no reliability or transmission constraint,(*i.e.* no separation of markets) such a unit would earn nothing, being a loser in the general market. In this sense, the presence of local market power necessarily raises some offer prices above the levels that would obtain absent this market power. If these offer prices are ever the marginal bid (the one that sets the market price), this local market power impacts the entire regional market.

Leveraging local market power

If this phenomenon were limited to a few small pockets connected to a large and extremely competitive regional market, the impacts would be contained within the isolated local areas. However, in markets such as California's, where many firms hold some form of locational advantage and are competing in an oligopolistic setting in the regional market, the opportunities created by local market power can effect even the larger markets.

[6] See Offer (1992), and Green (1994).

Consider the market described in Figure 2. This market is characterized by a series of interlinked monopolies, rather than a monopoly linked to a competitive region.

Suppose each firm acts as a residual monopolist in its local region, withholding output and allowing whatever imports that can travel over the limited transmission capacity that is available. But if every firm follows such a strategy, then the imports anticipated by each firm will not materialize.[7] Prices will everywhere be set at local monopoly levels. Yet all of these monopoly markets could in fact be linked into a single regional market if prices are roughly equalized and transmission remains unconstrained.

The prospect of earning local monopoly rents can therefore effectively cause firms to compete less aggressively in the larger regional markets. This effect produces an unusual form of inter-market leverage. Unlike the classic product tying strategy where the goal is to alter the structure of the tied market (see Whinston, 1990), it is the prospect of rents from a *decoupled* market that leads oligopolistic competitors to compete less aggressively for the common product, thereby causing the markets to remain linked.

This is because firms in most electricity markets are unable to explicitly price discriminate by location. Instead, all firms offer their supply to the entire regional market according to a single price schedule.[8] Thus, in most electricity markets, a firm cannot offer the production of a unit at price x for consumption at a given location, and at price $y < x$ for consumption elsewhere. Locational differences in prices are determined by the institution that manages transmission congestion and grid reliability, based upon the offer prices of generators. The actions of firms can therefore still effect locational market prices, but only through the market's protocols for setting spatial prices.

Because of this, firms may not always choose to price those generators with local market power at their local monopoly price. A more modest offer price might allow a unit with local market power to export its output beyond its own region. Therefore, firms can face trade-offs between higher local prices and greater regional volumes for their local output. The optimal offer price would depend on the size and competitiveness of the market beyond its local area, as well as the local monopoly profit level. In an oligopoly environment, optimal prices may also depend on the amount of local market power held by other firms.

The influence of local market power on pricing becomes more complicated when one considers firms that own many generators, with varying degrees of local market power. From the perspective of the regional market, where a strategically located unit could be part of a multi-unit supply portfolio, bidding strategies would be based not upon

[7] Borenstein, Bushnell, and Stoft (1996) examine a simple version of such a market structure, with two symmetric monopoly markets linked by a limited capacity transmission line. They find that for a given range of transmission capacity there is no pure strategy equilibrium for either Cournot or Bertrand competition between the firms.

[8] Even if suppliers could try to price discriminate by location, power traders would arbitrage those differences down to the true cost of transportation.

the marginal cost of the unit, but on the opportunity cost of its participation in the general market. In a setting of imperfect competition in a multi-unit auction common to most electricity markets, a mark-up over costs is sought, and usually achieved by suppliers.[9] With the addition of local market power, the costs that are being marked-up in the auctions for supply to the general market include local monopoly rents as well as production costs.[10] If any of these plants have a chance of setting the market price, this has the effect of raising prices not only in the local markets, but in the general market as well.

The impact of local market power in California appears to follow a similar pattern, with one important difference; the opportunity cost of selling into the regional market is set not by local monopoly revenues, but by a quasi-regulatory instrument, the reliability must-run (RMR) contract. Ironically, RMR contracts were developed to mitigate local market power, and if properly implemented they may have achieved that goal. However, generators are eligible to receive RMR payments only if they are not already committed to operate through an energy market. In other words, if a generator is a successful bidder in the day-ahead energy auction, it is not eligible to receive RMR payments. As we argue below, the prospect of lucrative type A RMR payments impacted the bids of the firms that own these units. This was not an isolated phenomenon as almost all of the generation units likely to be marginal in the California ISO system were considered must-run under some circumstances and were therefore eligible for RMR contracts.[11]

3 The California Electricity Market

The California electricity market is perhaps most notable for its disaggregation. Almost all of the major functions of a producer in an electric system have been unbundled and priced separately. Transactions for the core product, the hourly supply of electrical energy, can be reached in any of several overlapping day-ahead and hour-ahead markets, as well as an ex-post 'imbalance energy' market, which serves as the *de facto* spot market.[12]

[9]Borenstein, Bushnell, and Wolak (1999) estimate that market prices often substantially exceeded the marginal cost of the highest cost unit dispatched in the California electricity market. Wolfram (1999) estimates a significant price-marginal cost margin in England and Wales electricity market.

[10]Wolfram (1998), in the context of a multi-unit auction, examines the specific bidding behavior employed to achieve these mark-ups in the E&W pool. Among other results, she finds that the mark-ups bid by units conferred with 'constrained-on' status, *i.e.* those with significant local market power, bid significantly higher mark-ups than those without this status. Wolak (1998) characterizes and solves for the optimal bidding strategy which accounts for the impacts of financial hedge contracts on bidding behavior for a generator with multiple units in the Australian electricity market.

[11]The likelihood of being called under a RMR contract did vary greatly across generators, however.

[12]For detailed descriptions of these markets and the institutions that run them see Borenstein, Bushnell, and Wolak (1999), Wolak, Nordhaus, and Shapiro (1998) and Bohn, Klevorick and Stalon (1999).

Energy Markets

The two most prominent markets for electrical energy are the day-ahead market run by the California Power Exchange (PX), and the imbalance energy market run by the California Independent System Operator (ISO). The PX day-ahead market handles roughly 85% of the volume of day-ahead transactions.[13] The remaining 15% of day-energy scheduled through the ISO is scheduled by competitors to the PX, known as Scheduling Coordinators (SCs). The ISO imbalance energy market accounts for between 4% to 6% of energy transactions in California. The imbalance energy market is nevertheless a critical market in California, as it falls at the end of the chronological sequence of markets. Deviations from positions established in any prior markets, such as the PX day-ahead market, must be settled at the imbalance energy price. In other words, a producer that has scheduled a specific quantity of energy to be produced from a generating unit, who does not supply it, must purchase this energy from the ISO real-time energy market in order to maintain a balance of supply and demand.

The PX day-ahead market is a uniform-price double auction in which the hourly offer curves of suppliers are intersected with those of demanders - primarily, but not exclusively, the large distribution companies. Each market participant, even ones that have no retail load, is allowed to offer an unlimited number of production and demand portfolio bid functions, which take the form of monotonically increasing piece-wise linear supply and demand curves between the prices of zero and $2,500/MWh. Unlike most electricity markets around the world, including the the E&W electricity pool, supply offers into PX are not required to be linked to any specific production facility. Based upon these 'portfolio bid' offer curves, the PX calculates a state-wide forward energy price for each of the 24 hours in the following day. The aggregate amount of supply offers won at that price less the aggregate amount of demand offers won at that price gives the market participant's net forward position in day-ahead energy.

Suppliers with capacity that has not been scheduled to provide energy through one of the forward markets are eligible to provide both ancillary services and energy through the ISO. There are four types of ancillary services, or operating reserves, that are priced and purchased separately by the ISO. Ancillary service payments are provided for making capacity available for the supply of energy if the ISO requires it. These services are differentiated by the response time, ranging from near instaneous to 1 hour, required from the generator. Each supplier of ancillary services submits a bid price for a capacity payment as well as a bid price for energy. Selection of reserves is based solely upon the capacity price bid (see Chao and Wilson (1999) for more discussion of the rationale for this market design). In addition to acquiring reserves, the ISO also maintains the continuous balance of supply and demand by operating an imbalance energy market.

[13]During a four-year transition period beginning in 1998, the three largest distribution companies in the California market are required by law to purchase their energy requirements through the Power Exchange. This restriction has not prevented these companies from shifting some of their purchases to the ISO imbalance energy market, however (See Bohn, Klevorick, and Stalon (1999).

Any generator that has not committed to produce energy, including those that are providing ancillary service capacity, are eligible to bid to supply energy in real-time. These bids are step functions, and, unlike the PX, are linked to specific generation units. Providers of ancillary services are combined with other uncommitted generators that have bid to provide 'supplemental' energy into a real-time dispatch order according to their imbalance energy bid prices.[14] Those generators that are committed to supplying energy can also bid to decrement their output in the case of real-time oversupply. With these decremental energy bids, generators essentially buy-out of their committment to supply energy.[15] The ISO imbalance energy dispatch moves up and down these incremental and decremental offer curves and sets a uniform price every 10 minutes for the provision of imbalance energy based on either the highest-priced generator that is incremented or the lowest-priced generator that is decremented. These 10-minute prices are averaged into an hourly imbalance energy price. Hourly average deviations from advance energy commitments, such as the under-supply or over-consumption of energy, are then priced at this hourly imbalance energy price.

Transmission Markets and Spatial Prices

Spatial differences in energy prices are determined only over large zones within the ISO system. By far the largest zones are the NP15 and SP15 zones, which encompass most of northern and southern California, respectively. Most of the remaining 23 zones are interface points between the ISO and surrounding electricity systems, primarily those outside of California. When transmission congestion threatens to separate any of these zonal markets from each other, the ISO operates a day-ahead transmission market in which the bids of suppliers and consumers establish a uniform transportation price for power moving over a congested interface. There is no marginal charge for power moving over unconstrained interfaces.[16] The PX then sets zonal energy prices which differ according to the ISO transmission charge between those zones. Thus, when there is transmission congestion from southern to northern California, for example, the PX energy price will be higher in northern California than it will be in the south.

The ISO does not attempt to explictly price transmission congestion that arises *within* a zone. This remains a controversial feature of the California market. In order to relieve intra-zonal congestion, the ISO applies a procedure similar to that used in England and Wales. If there is congestion along a transmission path within the a zone due to the spatial mix of generators wishing to supply power in real time, then the ISO will

[14]The one exception is regulation reserve, the most responsive form of reserve. Because generators providing regulation are having their output continuously adjusted in both upward and downward directions, it is not possible to include these units in the real-time imbalance energy dispatch order. As such, providers of regulation reserve are not eligible to set the imbalance energy price, but they do receive this price for any net energy produced during the hour.

[15]Demand-side bidding for some ancillary services (non-spinning reserve and replacement reserve) and therefore supplemental energy is allowed.

[16]See Bushnell and Oren (1997) for a more detailed description of transmission pricing in the California market.

pay above market prices to certain generators in order to use their output to relieve this congestion. These payments are necessarily above-market, since there would have been no congestion if the necessary generation units had been willing to operate at the zonal market-clearing price. Additionally, there are operational constraints related not to specific transmission congestion, but to contingencies that reliability standards require the system to withstand without an interruption of service. These constraints are sometimes addressed through a process of intra-zonal congestion, but more often are dealt with in the context of must-run contracts, described below.

3.1 Reliability Must-Run Contracts

The problem of local market power was openly acknowledged by even suppliers during the design of California's electricity market. The issue was viewed primarily as one of reliability: if there are no substitutes for the output of a specific generator, how do we ensure that this 'must-run' generator operates? Such conditions may arise due either to intra-zonal congestion or due to more general reliability constraints. Concerns over local market power in part prevented the implementation of more localized energy prices, and thereby created the need for a contract to compensate generators who are forced to produce when the market-wide (non-localized) energy price is below their cost.

The Reliability Must-run Contract (RMR) is the instrument that was developed in California in order to deal with the problems associated with localized, must-run generation. Originally described as a 'call' contract, the idea was to create a way to compensate must-run generation for their 'above-market' costs when they are forced, due to reliability concerns, to operate even when the market price is below their operating costs. This extra compensation can be necessary whenever the market price is set by a simple matching of aggregate supply to aggregate demand, ignoring local grid constraints, as is done on a regional basis in California. Unfortunately, the terms and conditions of RMR contracts that were in place during the summer of 1998 did little to reduce the problem of local market power, and as we describe below, may have made the problem worse. The goal of our paper is to investigate this hypothesis empirically and quantify its magnitude, if it appears to be valid.

RMR Contract Terms

Although RMR contracts were conceived as a market-based mechanism intended to give the ISO an option on the output of certain generators,[17] the contracts that emerged from the restructuring process were fatally distorted by the regulatory legacy from which they emerged. The result was a mechanism that more closely resembled cost-of-service regulation than a market-based process. Contract rates were based upon the principle

[17]See Joskow (1998), and Jurewitz and Walther (1998)

Table 1: Summary of Fixed Cost Component of 1998 RMR rates(Millions $)

Unit's Owner Before Divestiture	PG&E	SCE	SDG&E	All RMR
Total Capital Cost Recovery	432.5	75.5	55.6	563.6
Total 1998 Capital Adds	39.2	15.9	6.6	61.7
Fixed O&M Costs	218.3	98.3	49.7	366.2
Fixed Fuel Costs	50.4	6.0	18.9	75.3
Auxiliary Power Cost	8.9	6.0	1.3	16.2
Total Annual Fixed Costs	710.1	185.8	125.4	1021.3

of full recovery of all costs, including sunk capital costs.[18] As table 1 shows, annualized capital costs accounted for more than half the fixed costs to be recovered, although the bulk of these costs were concentrated in the Pacific Gas & Electric (PG&E) system.

In general, it was thought that units that cannot recover their going forward costs in the deregulated market would be retired. If however, these units are needed for local reliability purposes, these going forward costs would have to be recovered through another mechanism, the RMR contract. Unfortunately, even sunk costs came to be incorporated into RMR payments under a similar line of reasoning. This logic assumes that the contracts would prevent these units from exercising their local market power, which would obviate the need for additional compensation. In the absence of market power mitigation, there would be little question that these units could recover their costs from the market, because they would be able to establish local monopoly prices for the output of individual generators during hours when these units are required for grid reliability reasons.

3.2 RMR Contract Forms

In this section we briefly describe the two most prominent forms of the original RMR contracts, the 'A' Contract and the 'B' Contract. Roughly speaking, the B Contract provided for an up-front payment to cover fixed and sunk costs while the A Contract attempted to roll those costs into a variable payment earned only when the unit actually provided RMR services. Generators under the B Contract were required to rebate a portion of their operating margins back to the ISO in order to offset their up-front fixed payments. As we shall discuss below, both contract forms created incentives that distorted offers into the energy markets.

[18] Sunk capital costs were included in contract payments despite the fact that the incumbent generation firms were guaranteed the recovery of their 'stranded' sunk costs through an alternative mechanism, the competition transition charge (CTC).

The A Contract

Originally, all must-run generators operated under A contracts. Many units subsequently switched to B Contracts, but the vast majority switched on or after October 1, 1998, beyond the time period that is the focus of this paper. The A Contract form had no up-front fixed payments. All costs to be recovered were allocated to a ($/MWh) variable payment. Estimates of annualized fixed and sunk costs for a unit were divided by a forecast of the total energy output from that unit in order to convert the fixed payments to variable amounts. These forecasts were based upon a simulation of the least-cost dispatch of the system, subject to local reliability constraints. The simulation did not consider the impact of market-power, or the incentives provided by the RMR contracts, on the forecast annual output of a unit.

Thus for each MWh of RMR energy provided by a generator under an A contract, that generator would receive a payment based upon its operating costs and a pro-rata share of its annualized fixed and sunk costs, based upon the forecast output levels of that unit. This last component, containing the fixed and sunk costs, is called the reliability portion of the RMR payment. For a few generation units with either extremely high sunk costs, or a low forecast of energy output, this payment is extremely large. For many others the payment is more modest, but can still constitute a significant mark-up over variable costs. Figures 3 and 4 show the aggregate marginal cost curve of thermal generators in California, as well as the aggregate cost curve of type A RMR contracts. At the extreme end, RMR contract rates were over 100 times marginal costs. Figure 3 is truncated as an RMR variable payment rate of $ 1000/MWh in order for the marginal cost curve to be visible. Figure 4 includes the remaining high A Contract RMR payment rates that extent to over $ 4000/MWh. Generators not operating at the time of the RMR call are also paid their start-up costs. In addition, these generators also receive a unit-specific commitment from the ISO that they will remain on-line for an agreed up number of hours.

Although it was originally intended that generators would not be allowed to recover more than 100% of their annualized fixed and sunk costs, this constraint was not included in the original A Contract. Under the A contract, if a unit is called upon to provide more RMR energy than its forecast total output, that unit could earn more than 100% of its annualized fixed and sunk cost from RMR payments.

The B Contract

Contract B was the original alternative to Contract A. The B contracts offer an up-front payment in exchange for a rebate of a portion market earnings. Under the B Contract, generators receive an up-front payment of their allocated annualized fixed and sunk costs. This payment, called the availability payment, is based upon a measure of the actual monthly availability of each unit, the fraction of hours in the month the unit is available to provide energy. When the output of a B Contract unit is needed, and it is not already scheduled to provide energy, the unit would also earn a ($/MWh) payment based upon its operating costs. In hours in which that unit is scheduled to provide energy (i.e. it has sold power in the PX or to another scheduling coordinator), its owner is obligated to pay back 90% of its sales margin, an estimate of its operating profit. In this way, units that frequently operate under RMR retain more of their fixed payments and units that frequently operate in the market retain relatively less of their fixed payments. Generators are not required to rebate any of their ancillary service revenues.[19]

RMR Dispatch Protocols

A central feature of the current RMR contracts is the 'market-first' principle upon which their operation is based. Rather than being a true call option, the RMR contract cannot be invoked at the ISO's discretion. Instead, the day-ahead energy and ancillary services markets are run before the ISO declares which generators are must-run units. Generation units therefore have the option to first bid into the energy or ancillary services markets. Only when a generation unit is not first dispatched in the energy market at a level of energy high enough to cover the ISO's local grid reliability needs, can it be called under the terms of an RMR contract. The abridged timeline in Figure 5 illustrates the market dynamics with regards to RMR calls.[20]

The protocol of 'market first' was adopted in order to prevent the ISO from taking advantage of RMR units whose rates are below the market clearing price, i.e. to prevent the ISO from price discriminating against generators. To be subject to an RMR call at a rate equal to its variable cost would deny an infra-marginal generation unit the opportunity to earn any operating profit in those hours when the price is appropriately above that unit's costs.

Under current protocols, the PX price is set as if the demand met by must-run units must instead be supplied from the PX. When RMR units are used to meet this demand, this practice seemingly produces a PX price that is higher than the bid of the true marginal unit. By essentially 'double-counting' some of the must-run demand, current protocols, even in the absence of strategic behavior, may therefore produce prices that are higher than the level that should actually clear the market. Figure 6 draws upon the example in Figure 1 to illustrate this point. Recall that the system-wide market price of P_1 was not high enough to compensate the must-run generator in the north. The northern demand is instead met by calling the northern unit under an RMR contract. However, there is no longer a need to supply this demand through the system-wide market and the previous price of P_1 is now too high. Once this demand is removed, as illustrated on the right hand side of Figure 6, the true market clearing price becomes P_2. This is the true price of additional system-wide supply.

[19] The 'deemed revenue,' upon which the sales margin is based, was set at the PX price for some firms, but for other firms deemed revenues were based upon other terms. Estimation of the actual revenues and profits that a unit with a B Contract earns in each hour that it participates in an energy market has therefore become another dimension over which disputes have arose.

[20] Only the aspects of the market timing directly of concern here are illustrated in Figure 5. A more comprehensive discussion of the market timing is given in Bohn, Klevorick, and Stalon (1999).

However, the above analysis is further complicated by the interaction of the day-ahead energy markets with the ISO 'real-time' imbalance energy market. While the PX price may be set above the true price of an additional unit of supply, we would expect this supply to be made available to the imbalance energy market through ancillary service or supplemental energy bids. Because both suppliers and demanders are free to move between the day-ahead and real time markets by the aggressiveness of their bids in the day-ahead PX market. We would expect loads to attempt to shift their purchases across the two markets by their bidding behavior in the PX to minimize their total purchased energy costs. Generators will also shift their supplies into the various markets to maximize their expected profits from energy sales. In the empirical analysis below, we therefore analyze the effect of RMR contracts on demand, as well as supply bids in the PX. As we discuss below, however, the ability of consumers to completely offset the incentive effects of RMR contracts, and their incentives to do so, are somewhat constrained. In this regard, it is important to recognize that California state law AB 1890 requires that the three investor-owned utilities–Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric–purchase all of their forward energy commitments from the PX, with any energy imbalances made up in the ISO's real-time energy market. We examine the interaction of the day-ahead PX market and the ISO imbalance energy market in more detail in Section 5.

3.3 RMR Contracts and Bidding Incentives

The recovery of fixed and sunk costs in per-unit payments distorts a generator's incentives for bidding into the energy and ancillary services markets. By creating an alternative stream of revenue that sometimes far exceeds market prices, type A contracts create an opportunity cost for generators to participate in the market. In other words, if a generator is dispatched through the PX, it has lost the opportunity to earn RMR revenues in that hour. Profit-maximizing generators should therefore base their bidding strategies upon their *expected RMR revenues*, rather than their marginal cost when those revenues exceed marginal cost. If enough generators are influenced by these opportunities, market prices themselves will be driven upwards from what they might have been without RMR contracts. This is the effect that we examine empirically in Section 4.

The incentives for bidding into the PX for units under B Contracts are distorted because these units are required to refund the bulk of their operating profits. As long as the variable costs upon which the rebates are based are accurate, units still make some profit from participating in the energy markets. However, firms with a portfolio of generation resources that include some B Contract units have an additional incentive to withhold the output of the B Contract generation in order to raise the market price received by its other resources. In other words, the downside of withholding B Contract units from the market, or of bidding them in at very high prices, is minimized by the rebate requirement. Such units have less to lose from pursuing such a strategy, because they would have to rebate the bulk of their operating profits anyway. During the summer of 1998, the period studied below, very few units operated under B Contracts.

The effects of B Contracts also do not parallel those of local market power, in the way that A Contracts do. Incentives to withhold the output of units under B Contracts are not related to the expected must-run status these units. These units are required to refund the bulk of their market profits regardless of the local demand for the output of those units. In contrast, the profit of a generator with a type A RMR contract, which pays more–sometimes far more–than marginal cost per unit of production, is increasing in the amount of capacity that is expected to be called under the RMR contract. The Contract A RMR effect can therefore be measured using differences in the expected quantity of RMR calls within an hour and differences in bids submitted to the PX. Measuring the Contract B RMR effect would require observing the California energy market with and without RMR Contract B and computing the differences in bidding behavior across these two regimes.

Empirically, there are several ways in which we can begin to link the opportunity cost of participating in the energy market to the observed behavior of the generators. The relative benefits to a generator of either selling into the PX or withholding capacity from all markets will depend upon the PX price and the expected RMR revenue of that generator. The expected RMR revenue of a generator in turn depends upon its RMR payment level and the probability that its energy will be declared 'must-run.' Because of the complications of portfolio bidding and other factors, this trade-off is not necessarily a direct one.

If RMR incentives are impacting generator behavior, from the above intuition we would expect that when the PX price is low relative to the RMR payment levels of 'must-run' generators, we would see relatively high amounts of RMR energy. Conversely, when the PX price is high relative to the RMR rates being earned by must-run units we would expect to see most of those units participating in the market. This pattern is, in fact, exactly what we observe for the months of June through August.

In each hour, the ISO identifies the energy from each unit that it considers to be must-run for various reliability purposes. We describe this amount as the 'gross' RMR energy needed. Usually, some of this energy is provided through the PX or bilateral transactions. These generators would therefore be operating whether or not the ISO took any further action. At other times, however, there are units that the ISO considers to be must-run that do not schedule any energy or sufficient energy to meet the ISO's gross RMR energy requirement from that unit. These units must therefore be called to provide energy under RMR contracts. We use the term 'net' RMR energy to describe the difference between the gross RMR need for must-run energy for a unit and the amount of energy that is scheduled from that unit on a day-ahead basis, if this difference is greater than or equal to zero. Otherwise, the net RMR energy from a unit that has a positive gross RMR need is zero. In other words, net RMR energy = max(0, gross RMR energy - scheduled energy).

Figures 7 through 10 show the PX price and the average RMR rate earned by Contract A generators declared to be must-run. That is to say, the average RMR rate of the gross RMR energy supplied by Contract A RMR units only. This quantity weighted average hourly price is obtained as the sum of the product of unit level gross RMR energy times the RMR payment rate for that unit summed over all Contract A RMR units and divided by the sum of the gross RMR energy over all Contract A RMR units. The hour-by-hour set of generation that is 'must-run' is much more stable than the associated set of generation used to supply total hourly demand. Therefore the average RMR rate for the 'gross' must-run energy needed is less volatile, averaging around \$100/ MWh in June and around \$60/MWh in the other months. In June and in the later parts of September, the PX price is consistently far below the average rate for RMR units. At other times, particularly from late July through early September, the PX price was much closer to the average RMR rate, and frequently exceeded it. During such periods, RMR units were therefore more frequently 'on the margin,' based upon their RMR revenues rather than their marginal cost. Therefore, it is during these times that we would expect RMR contracts to most significantly impact PX prices.

Figures 10 through 13 show the hour-by-hour gross must-run energy needed and the net energy that needed to be purchased under RMR. From these figures, we can see that the 'net' RMR energy much more closely follows the 'gross' need for RMR energy in months such as June and late September when the PX price is considerably lower than the average hourly RMR rate. In other months, when the PX price is relatively high, most of the RMR generators prefer to schedule their energy through the market, rather than through their uncertain RMR contracts. These results imply that generators did indeed utilize their A type RMR contracts, with the associated revenues, in a profit-maximizing way. We examine the nature of this RMR contract effect on bidding behavior in the following section.

4 Impact of RMR Contracts on Bidding Behavior

In this section, we estimate more directly the impact of A type RMR contracts on the bidding behavior of participants in the PX day-ahead energy market over the period June 1, 1998 to September 30, 1998 using demand and supply bid data from the PX and RMR and other operations data from the ISO. Our analysis attempts to isolate the effect of expected RMR calls on the offer prices of the owners of those units as well as on the offer prices other firms. Given the incentives provided by type A RMR contracts, our hypothesis is that a larger amount of expected must-run generation would lead to higher offer prices from the owners of those units.

Several aspects of the PX protocols complicate estimating the impact of A type RMR contracts on bidding behavior. First, the bidding protocols of the PX do not link a firm's supply offers to specific generation units or demand offers to specific loads. Second, each hour all market participants can submit as many portfolio supply and demand bid functions as they like. Each supply portfolio bid function is required to be a piece-wise linear increasing functions of prices between \$ 0/MWh and \$ 2500/MWh and can contain at most 16 bid segments. Each portfolio demand bid function is required to be a piece-wise linear decreasing function of prices between \$ 0/MWh and \$ 2500/MWh and can contain at most 16 bid segments. During our sample period all but a small number of market participants submitted both demand and supply side bids during many hours. This fact reinforces our earlier point that the PX is purely a day-ahead financial forward market. The difference between the amount of supply bids taken at the market price less the quantity of demand bids taken at the market price gives the long position in the forward energy market of that market participant. Under the California market rules, a generator is also not required to submit to the ISO a day-ahead energy schedule equal to this forward energy position.

Because of these aspects of the PX market we cannot estimate the impact of the RMR status of a specific unit on the offer price for that unit. Unlike Wolfram's (1998) study of bidding in the England & Wales pool, we also cannot examine the mark-up over cost of a specific generating unit in the PX, because no specific bid is linked to a specific generator. In fact, there are many times when a market participant's PX energy position differs in sign from its net position in all of the energy markets. In particular, net demanders of energy are often long energy in the PX and net suppliers of energy are often short energy in the PX. As a consequence, we must examine the impact of expected RMR calls on the portfolio bidding behavior of each market participant in the PX.

As discussed in Wolak (1998), a competitive electricity market is a non-cooperative game with an extremely high-dimensional action space. In the case of Australian electricity market, the action space of any generator was high-dimensional, but still finite. In the case of the PX, the dimension of the action space is countably infinite. The hourly action space for a market participant is the set of all continuous increasing functions with support on the interval [0,2500] that range from $(-\infty , \infty)$. The logic for this claim follows. For firm i, each portfolio supply function $S_{i\ell}(p)$, $\ell = 1, ..., N$ (N equals the number of supply portfolio bid functions submitted), has support on the interval [0,2500], ranges from $(0, \infty)$ and is piece-wise linear and increasing. Because a participant can submit as many portfolio bids as it desires, the set of feasible aggregate supply bid functions submitted by firm i,

$$S_i(p) = \sum_{l=1}^{N} S_l(p)$$

approaches a continuous, increasing function as N tends to infinity. A similar logic follows for the set of portfolio demand functions. Consequently, firm i's action space in the PX is the difference between its aggregate supply bid function and its aggregate demand bid function, or its net supply function

$$SN_i(p) = S_i(p) - D_i(p)$$

which approaches an increasing function with support on [0,2500] that ranges from (∞, $-\infty$). Given the market clearing price p_m the generator's net supply hedged in the PX is equal to $SN_i(p_m)$. If the generator manages to set p_m in the PX through its combined demand and supply bids, then $SN_i(p_m)$ is net long forward position in energy it has hedged through the PX with the action $SN_i(p)$. An illustration of the construction of a net supply bid curve from the supply and demand bid curves is given in Figure 15. The net quantity supplied at the PX market-clearing price, PXP, for a given hour can be read off the horizontal axis as SN_{PXP}. As show above, this net supply bid curve is the difference of the aggregation of all portfolio bid supply curves submitted by that market participant during that hour less the aggregation of all portfolio demand bid curves submitted by that market participant during that hour.

Because a participant's strategy is a mapping from its information set to its action space, we can write the firm i's strategy for hour j as $SN_{ij}(p, \theta_{ij})$, where θ_{ij} is the vector of information available to firm i at the time it submits its portfolio bid for hour j. Variables that enter into θ_{ij} include the day-ahead forecast of the total ISO load for that hour, the expected quantity of contract A gross RMR calls from that participant's units for that hour ($ERMROWN$), the expected quantity of contract A gross RMR calls from all other units for that hour ($ERMROTHER$), the marginal cost of producing electricity for all units owned by that participant, and any information possessed by that participant that may or may not be observed by other participants but is not observed by the econometrician. Note that the actual quantity of contract A gross RMR calls from that participant's units for that hour ($RMROWN$) and the actual quantity of contract A gross RMR calls from all other units for that hour ($RMROTHER$) do not enter θ_{ij}. These variables are unknown to the generator at the time it bids into the PX for all 24 hours during the following day.

We would like to assess the impact of contract A RMR calls on generator bidding behavior. We must therefore assume that $ERMROWN$ and $ERMROTHER$, rather than the variables that forecast $RMROWN$ and $RMROTHER$, enter θ_{ij}. This requires us to either specify an explicit statistical model that the participant uses to forecast these variables, or to assume that linear functions of $ERMROWN$ and $ERMROTHER$ enter into $SN_{ij}(p, \theta_{ij})$ and that the expectations of the difference between $RMROWN$ and $ERMROWN$ and the difference between $RMROTHER$ and $ERMROTHER$ are zero. Under this second set of assumptions we can apply instrumental variables techniques with $RMROWN$ and $RMROTHER$ replacing $ERMROWN$ and $ERMROTHER$ in θ_{ij} when we estimate the impact of the $ERMROWN$ and $ERMROTHER$ on the bidding behavior of the market participant. Because we do not have an explicit theoretical model to use to derive the functional form of $SN_{ij}(p, \theta_{ij})$ from, we assume for functional form for this function such that $ERMROWN$ and $ERMROTHER$ enter linearly, so that instrumental variables techniques can be applied. In addition, because we have very little prior knowledge about the precise manner in which $ERMROWN$ and $ERMROTHER$ might enter $SN_{ij}(p, \theta_{ij})$ we select this linear functional form as the first-pass model. We have estimated models which use more complex functional forms for $ERMROWN$ and $ERMROTHER$ and obtained similar results for the impact of contract A RMR calls on bidding behavior.

At this point we should note that because of the portfolio bidding rules of the PX and the fact that the net supply quantity won through the PX need not be either scheduled day-ahead or produced in real-time, there are few of the reasons that exist in other markets around the world and the US for the dependences in the optimal $SN_{ij}(p, \theta_{ij})$ functions across the 24 hours of the day. For example, for the case of Australia and the England and Wales markets, the bid price for a specific increment of a generating unit is set for the entire day but the quantity available from that increment can be varied on a half-hourly basis. This imposes substantial linkages between the optimal half-hourly bid functions across all half-hours in the day. These sorts of linkages are not present in the PX. Consequently, we do not expect the fact that we are focusing on the hourly strategies in our analysis to exert a significant influence over our results. The impact of type A RMR contracts on daily bidding behavior is likely to be even larger, because when a generator is asked to start-up to supply RMR energy, these costs paid for under the terms of the RMR contract. A daily model is likely to do a better job of capturing the impact of this incentive on bidding behavior than a model that treats the hours of the day independently. Consequently, because of the complexity of estimating an econometric model which links the 24 hourly net supply bid curves across the day and the fact that the hourly model is likely to give us a conservative estimate of the impact of contract A RMR calls, we focus on an econometric model of the hourly net supply function.

Because we wish to quantify directly the impact of $ERMROWN$ and $ERMROTHER$ on the prices bid into the PX, we instead estimate $SN_{ij}(p, \theta_{ij})$ in terms of its inverse bid price function $p = PB_{ij}(SN, \theta_{ij})$ which exists for all p and SN, because PX protocols require that $SN_{ij}(p, \theta_{ij})$ be strictly monotone increasing in p. Our choice of a functional form for $PB_{ij}(SN, \theta_{ij})$ is driven by two criterion. First, we wish to be as flexible as possible with regards to all the variables besides $ERMROWN$ and $ERMROTHER$, so as to not attribute to $ERMROWN$ or $ERMROTHER$ some nonlinear impact of the other elements of θ_{ij} and SN on the firm's bid price. Second, we also need a functional form that allows for a tractable calculation of a counterfactual net supply curve under the assumption that there are no contract A RMR calls. These counter-factual supply curves allow us to estimate the impact of these contracts on bidding behavior and on market prices. The resulting counter-factual predicted PX prices are then used to construct an estimate of the increased costs of purchasing energy in the California energy markets as a result of type A RMR contracts.

In order to present our functional form for $PB_{ij}(SN, \theta_{ij})$ we require the following notation. For each market participant, i, and each hour, j, of each day, k, define the following notation:

$SN_{ijk}(p) = S_{ijk}(p) - D_{ijk}(p)$, the net supply by firm i in hour j of day k at the price p

PXP_{jk} = the PX price for hour j of day k at the price p

$RMROWN_{ijk}$ = the gross quantity of RMR calls in hour j of day k from units owned by firm i

$RMROTHER_{ijk}$ = the gross quantity of RMR calls in hour j of day k from units owned by all other firms besides firm i

$y_{ijk}(SN) = \ln(p+1)$ = the natural log of 1 plus the bid price at the net supply quantity, SN, for firm i, for hour j of day k. (Because the bid price is sometimes equal to zero we must translate it by 1 before taking the log.)[21]

$DA\_ISO\_LOAD_{jk}$ = the day-ahead ISO load forecast for hour j of day k

$MONTH_{km}$ = dummy variables which take on the value 1 if day k is in month m and zero otherwise, where $m = 6, 7, 8, 9$ corresponds to June, July, August and September, respectively.

DAY_{kd} = dummy variables which take on the value 1 if day k is day-of-the-week d and zero otherwise, where $d = 1, 2, ..., 7$ corresponds to Sunday through Saturday, respectively.

$HOUR_{jh}$ = dummy variables which take on the value 1 if hour j is hour-of-the-day h and zero otherwise, where $h = 1, 2, ..., 24$ correspond to hours 1 to 24, respectively.

$\epsilon_{ijk}(SN)$ = the unobserved portion of the inverse bid price for firm i in hour j of day k at net supply quantity, SN.

In terms of this notation we can write $\ln(PB_{ijk}(SN, \theta_{ijk}) + 1)$, the log of the bid price at each value of SN^v, where SN^v is one of the vertices of the piece-wise linear bid price curve, $PB_{ijk}(SN, \theta_{ijk})$, for hour j of day k as:

$$\begin{aligned} ln(PB_{ijk}(SN, \theta_{ijk}) \ + \ 1) \ = \ & \alpha_i + \sum_{a=1}^{3} \gamma_{ia}(SN)^a + \sum_{b=7}^{9} \delta_{ib} MONTH_{kb} + \sum_{c=2}^{7} \eta_{ib} DAY_{kc} \qquad (1) \\ & + \sum_{d=2}^{24} \omega_{id} HOUR_{jd} + \beta_{i1} ERMROWN_{ijk} + \beta_{i2} ERMROTHER_{ijk} \\ & + \sum_{g=1}^{3} \phi_{ig} (DA\_ISO\_LOAD_{ijk})^g + \epsilon_{ijk}(SN) \end{aligned}$$

We could estimate this model using every bid price and net supply quantity vertex of the piece-wise linear bid price function to estimate the parameters of this equation. This would imply a large and variable number of observations each hour. In addition, as

[21]Translating the bid prices by one guarantees that the lowest possible value of ln(p+1) is zero. Translating the bid price by other values less than one did not impact either the regression results or our estimates of the cost of type A RMR contracts presented below.

discussed in Wolak (1998), unless the portion of a market participants bid curve has a non-zero probability of setting the market price given the demand uncertainty perceived by that bidder, the optimal bid function is not uniquely defined over this range of bids. For example, in Figure 15 if the probability that bid prices below a certain magnitude will be marginal is equal to zero, then the only restriction optimal bidding places on the net supply curve is that it lies below the first bid price that does have a non-zero probability of being marginal. For example, if PXP in Figure 15 is first price that has positive probability of being marginal, any function that is montone increasing to that price level yields the same expected profits for the firm. This implies that price and net supply pairs that have a low probability of setting the market price, contain significantly less information about the impact of $ERMROWN$ and $ERMROTHER$ on the prices bid into the PX. Consequently, in recovering the impact of RMR contract A calls on bidding behavior it is important to select a net supply quantity that has a high probability of clearing the market, and estimate the regression using this price and net supply pair across all hours and days.

Because we have the freedom to pick any point along the net supply curve to recover the impact of $RMROWN$ and $RMROTHER$, we select the value of SN that actually cleared the market. In other words, we pick the value of SN for firm i in hour j of day k corresponding to the PX price in hour j of day k price. Define this value of SN_{ijk} as $SNPX_{ijk}$. The equation we estimate over hours and days in the sample for each market participant is:

$$\begin{aligned} y_{ijk} \quad = \quad & \alpha_i \ + \ \sum_{a=1}^{3} \gamma_{ia}(SNPX_{ijk})^a + \sum_{b=2}^{4} \delta_{ib} MONTH_{kb} + \sum_{c=2}^{7} \eta_{ib} DAY_{kc} \\ & + \sum_{d=2}^{24} \omega_{id} HOUR_{jd} + \beta_{i1} ERMROWN_{ijk} + \beta_{i2} ERMROTHER_{ijk} \\ & + \sum_{g=1}^{3} \phi_{ig}(DA\_ISO\_LOAD_{ijk})^g + \epsilon_{ijk} \end{aligned} \tag{2}$$

where $y_{jk} = \ln(PXP_{jk}+1)$. This regression equation captures the intuition that bid prices for a participant depend on the month, day-of-the-week, hour-of-the-day, a nonlinear function of the net supply at that price, a nonlinear function of the day-ahead forecast of the ISO load, and the forecast quantity of $RMROWN$ and $RMROTHER$ during that hour. We experimented with including higher powers of both SN and DA_ISO_LOAD in equation (2), but our estimation and counterfactual PX price calculations did not significantly change.

The time path of total ISO load throughout the day–the values of DA_ISO_LOAD for all 24 hours of the day–should impact RMR calls in each hour of the day, yet be orthogonal to ϵ_{ijk} for all hours of the day and all market participants. Therefore, we estimate the parameters of this model for each market participant by two-stage least squares (2SLS), replacing $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ by $RMROWN_{ijk}$ and

$RMROTHER_{ijk}$, respectively, using DA_ISO_LOAD, $(DA\_ISO\_LOAD)^2$ and $(DA\_ISO\_LOAD)^3$ for all other hours in day k as instruments for $RMROWN_{ijk}$ and $RMROTHER_{ijk}$, because, as noted earlier, these two variables are assumed to be unbiased forecasts for $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ given this information set.

This assumption implies that each generator is able to forecast both $RMROWN$ and $RMROTHER$ for each hour in the day using the first three powers of day-head ISO load forecast for all hours of the day in addition to all of the remaining variables in equation (2) besides $RMROWN$ and $RMROTHER$. For all market participants these first-stage regressions forecast the values of both $RMROWN$ and $RMROTHER$ quite well. These first-stage regressions are computed by ordinary least squares regressions of the value of $RMROWN_{ijk}$ and $RMROTHER_{ijk}$ on a constant, the three powers SN_{ijk}, the month day and hour indicator variables and the first three powers of DA_ISO_LOAD for all hours in day k. The predicted values of $RMROWN_{ijk}$ and $RMROTHER_{ijk}$ from these two regressions will used to compute our estimate of the cost of RMR type A contracts

At this point it is useful to discuss some of the assumptions underlying our method for computing the impact type A RMR contracts on market participant bidding behavior. An assumption implicit in our analysis is that where the aggregate bid demand curves cross the horizontal axis and where the aggregate supply bid curve for a given market participant turns vertical does not change as result of contract A RMR calls. These contract A RMR calls can only impact the price at which a specific quantity is bid into the PX not the total quantity bid into the market. Consequently, if market participants are bidding less total demand (demand at zero price) or supply (supply at the price of $2,500/MWh) into the PX as a result of RMR contracts, our procedure would not capture this effect. In Wolak and Bushnell (1999) we present evidence which appears consistent with the view that some capacity withholding on both sides of the PX market may have occurred over our sample period. However, withholding on the supply side of the market appears to be more extreme than that on the demand side of the market. If this was in fact the case, it would bias downwards our estimates of the increased costs of type A RMR contracts on PX prices.

4.1 The Price Impacts of RMR Contracts

Over the summer of 1998, there were 7 firms that owned significant generation capacity within the California ISO system, the 3 incumbent investor owned utilities (IOUs), and four firms that purchased gas-fired capacity divested by the IOUs. There were also many other firms with relatively smaller positions in the California market.[22] Most of these 7 firms also owned generation capacity with type A RMR contracts during this period. We estimate equation (2) for four 'new' RMR generation owners [Duke Energy, Dynegy, AES,

[22]See Borenstein, Bushnell, and Wolak for a more detailed description of the market structure in California during this period.

and Reliant Energy (formerly Houston Industries)], the three incumbent investor-owned utilities (IOUs) [Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric], and a residual market participant composed of all remaining bidders into the PX. For those market participants that own no contract A RMR units, we assume that $ERMROWN$ is equal to zero for all hours and days in the sample.

Given our assumed functional form for the bid price function, our estimate of the impact of RMR contracts on bid prices is constructed as follows. Represent all other elements of the equation besides the term

$$\beta_{i1} RMROWN_{ijk} + \beta_{i2} RMROTHER_{ijk}$$

as $X'_{ijk}\Gamma_i$, where X_{ijk} is the vector of regressors and Γ_i is the vector of coefficients for firm i. Take the exponential function of both sides of equation (2). Using this notation,

$$p_{ijk} + 1 = \exp(\beta_{i1} ERMROWN_{ijk} + \beta_{i2} ERMROTHER_{ijk}) \exp(X'_{ijk}\Gamma_i + \epsilon_{ijk})$$

To adjust for the impact of the opportunity cost of RMR contracts on the bidding behavior of this firm, we set the values of $ERMROWN$ and $ERMROTHER$ equal to zero, so that

$$p_{ijk} + 1 = \exp(X'_{ijk}\Gamma_i + \epsilon_{ijk})$$

because $\exp(0) = 1$. The term

$$C(i,j,k) = 1/[\exp(\beta_{i1} ERMROWN_{ijk} + \beta_{i2} ERMROTHER_{ijk})] \tag{3}$$

is the factor predicted by our econometric model that will adjust all bid prices submitted by the firm during hour j of day k for the impact of RMR contracts. Note that we are not guaranteed to find $C(i,j,k)$ less than 1. In fact, for several market participants, in many hours the value of $C(i,j,k)$ is greater than one.

To compute our estimate of this RMR impact factor on price bids into the PX requires an estimate of the coefficients β_{i1} and β_{i2} and estimates of $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ for each hour, day and market participant. The estimates of $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ are the predicted values from the first stage regression of each of these variables on all of the exogenous variables in equation (2) and the vector of instruments.

We apply this factor to all bid prices, *pbid*, for all interior demand and supply portfolio bid prices (all bids points except those with prices at \$0/MWH and \$2500/MWH) in every portfolio bid submitted by the firm i during hour j of day k to construct our prediction of the bid price at the associated net supply level in the absence of the bidding incentives provided by the current RMR contracts. Figure 16 gives a graphical example of the impact of this calculation on the aggregate supply and demand bid functions for a market participant. This process yields

$$pbid^{NORMR}_{ghijk} = [(pbid_{ghijk} + 1) * C(i,j,k)] - 1 \tag{4}$$

as the adjusted bid price associated with each the original bid price for vertex g of the portfolio bid curve h for market participant i, in hour j or day k. Note that the RMR factor, $C(i, j, k)$, varies depending on the market participant, hour and day, so that the impact of RMR contracts of the price bid depends on these variables. More complicated specifications which made $C(i, j, k)$ depend on the level of the day-ahead forecast of ISO load, the value of net supply at that bid price, led to similar sample means of the $C(i, j, k)$ for each market participant.

4.2 Results

Because the hourly bid data used to estimate equation (2) is confidential, we do not present the parameter estimates of (2. Nevertheless, to give the reader idea of the magnitude and precision of the estimated RMR effect for each market participant we present in Table 4.2 the monthly sample mean values of $C(i, j, k)$ for each month in our sample and for each market participant. Define this magnitude as

$$\bar{C}_i^m(\hat{\Delta}_i) = \frac{1}{24D_m} \sum_{j=1}^{24} \sum_{k=1}^{D_m} C(i, j, k, \hat{\Delta}_i) \tag{5}$$

where D_m is the number of days in month m, $\hat{\Delta}_i$ is vector composed of estimates of β_{i1} and β_{i2} and the parameters of first-stage regressions of $RMROWN$ and $RMROTHER$ on the vector of exogenous variables in equation (2) and the instruments for firm i.

Because parameter vector $\hat{\Delta}_i$ is estimated, there is randomness in $\bar{C}_i^m(\hat{\Delta}_i)$ due to this estimation error. Consequently, we also present a standard error estimate for this sample mean computed using the bootstrap. There are two sources of estimation error in $\hat{\Delta}_i$. The first is due to the fact that β_{i1} and β_{i2} are estimated. The second is due to the fact that parameters of the first stage regression used to compute our prediction of $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ are also estimated. Our bootstrap procedure resamples from the empirical distribution of the error to equation (2) and the errors to the first stage regressions used to construct $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ to construct each resample of the original data. We then estimate the first-stage regression used to construct $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ and re-estimate equation (2) with our bootstrap resampled dependent variables in the three equations. This gives bootstrap estimates of $ERMROWN_{ijk}$ and $ERMROTHER_{ijk}$ and β_1 and β_2, which are used to compute a bootstrap resample of $C(i, j, k, \hat{\Delta}_i)$. We then compute the sample mean of the bootstrap resamples of $C(i, j, k, \hat{\Delta}_i)$ for all hours in each month. This gives one bootstrap resample of the monthly sample mean of $C(i, j, k, \hat{\Delta}_i)$. Repeating this entire procedure B times, and computing the standard deviation of these resampled monthly sample means gives the bootstrap standard error estimate of the monthly mean $\bar{C}_i^m(\hat{\Delta}_i)$. We use B = 50 to compute all of the boostrap standard error estimates reported in this paper. The Appendix describes this bootstrap procedure in detail.

Table 2: **Monthly Sample Average Hourly RMR factor by firm**

Firm	**Month**	**Monthly Mean RMR factor**	**Standard Error**
0	6	0.86804	0.050426
0	7	0.90756	0.039683
0	8	0.89029	0.048268
0	9	0.91279	0.034549
1	6	0.76928	0.039989
1	7	0.80483	0.033021
1	8	0.75141	0.040362
1	9	0.82615	0.029873
2	6	1.01915	0.077091
2	7	0.81929	0.032612
2	8	0.78266	0.038609
2	9	0.84502	0.028562
3	6	0.78895	0.041407
3	7	0.82848	0.034147
3	8	0.79324	0.040656
3	9	0.85311	0.029732
4	6	0.80699	0.040278
4	7	0.84332	0.033154
4	8	0.81098	0.039639
4	9	0.86605	0.028856
5	6	0.93623	0.040063
5	7	0.94894	0.032173
5	8	0.93774	0.039093
5	9	0.95665	0.027345
6	6	0.76493	0.040701
6	7	0.88187	0.037612
6	8	0.85104	0.045202
6	9	0.90490	0.033348
7	6	0.72503	0.038387
7	7	0.85952	0.031257
7	8	0.82506	0.037747
7	9	0.84977	0.027890

From the results in Table 4.2 we can see that the monthly mean RMR factors are below 1 for all months and market participants, except for the month of June for market participant 2. In addition, the bootstrap standard errors for these monthly means indicate that they are very precisely estimated for all months and market participants. The fact that all but one of the monthly mean RMR factors are less than one does not mean that all of the hourly RMR factors are equal to zero. In fact, for most market participants there are many hours when the RMR factors are greater than or equal to one. These tend to be the periods when both $RMROWN$ and $RMROTHER$ are small.

This is consistent with the view that the ability to leverage the local market power covered under the RMR contract is closely linked with the level of overall market power in the regional market. As demonstrated in Borenstein, Bushnell, and Wolak (1999), there is significant variation in the level of market power in the California market with the higher demand periods experiencing considerable market power while the lower demand periods appear to be highly competitive. Because the RMR variables are highly correlated with overall ISOLOAD, the periods of low RMR quantities are also those periods of low demand, and therefore low regional market power.

To illustrate this ISO high load period phenomenon of the impact of type A RMR contracts on bidding behavior, in Table 4.2 we compute the sample mean values of all same average value of the RMR factor for three periods during the day for each market participant. Each of these periods is of length 8 hours. MORNING runs from 12 am to 8 am. DAY runs from 8 am to 4 pm. NIGHT runs from 4 pm to 12 am the following day. For all market participants, the average value of the $C(i, j, k)$ over the DAY period is lower that the average value for the other two time periods. NIGHT is the next highest average value and MORNING is the highest average value. We also present the bootstrap standard errors for these sample average values. These indicate that the means of $C(i, j, k)$ over these three time periods in the day are precisely estimated, although for several market participants the differences between the mean values across the three periods in the day are not statistically significantly different, meaning that a test of the null hypothesis that the two means are equal cannot be rejected at standard levels of significance.

Given that we have constructed the bid prices associated with all portfolio demand and supply bids using the procedure described above for all market participants, we can now estimate the PX price and market cost impacts of eliminating the type A RMR contract. We do this by re-computing the market-clearing PX price and quantity associated with these counter-factual portfolio demand and supply bid curves. These counter-factual bid curves incorporate our estimate of the impact of eliminating type A RMR contracts on both the aggregate demand and aggregate supply bids of each market participant.

With these new aggregate demand and supply bid curves, we then construct the implied aggregate PX supply curve in the absence of the current RMR contracts and intersect it with the implied aggregate PX demand bid curve in the absence of the current

Table 3: **Sample Average Hourly RMR factor by time-of-day**

Firm	**Month**	**Mean RMR factor**	**Standard Error**
0	DAY	0.86974	0.053275
0	MORNING	0.92688	0.029172
0	NIGHT	0.88759	0.045449
1	DAY	0.73141	0.044319
1	MORNING	0.85887	0.024875
1	NIGHT	0.77299	0.038148
2	DAY	0.81098	0.048395
2	MORNING	0.93515	0.031312
2	NIGHT	0.85024	0.042674
3	DAY	0.76852	0.045069
3	MORNING	0.87543	0.025346
3	NIGHT	0.80364	0.039067
4	DAY	0.78820	0.043932
4	MORNING	0.88654	0.024521
4	NIGHT	0.82055	0.038021
5	DAY	0.92993	0.043882
5	MORNING	0.96361	0.023061
5	NIGHT	0.94106	0.037108
6	DAY	0.77585	0.046053
6	MORNING	0.94539	0.031391
6	NIGHT	0.83160	0.040775
7	DAY	0.74414	0.041401
7	MORNING	0.90741	0.023714
7	NIGHT	0.79434	0.035398

A RMR contracts. Note that both the aggregate supply and demand curves shift, because we adjust the bid price for both curves by the firm level RMR factors. Figure 17 plots the original aggregate supply and demand bid curves with the intersection of these two curves at the point (PXQ,PXP). The aggregate supply and demand bid curves in the absence of the incentives caused by the current RMR contracts are also shown in this figure, intersecting at the point (PXQP, PXPP). Note that the aggregate adjusted PX demand curve still intersects the horizontal axis at the same point as the original PX aggregate demand curve and the PX adjusted aggregate supply curve reaches the same maximum quantity level at a price of $ 2500/MWh as the original PX supply curve. These two results occur because of our conservative assumption of no capacity withholding as result of type A RMR contracts.

Because both the PX aggregate supply bid curve and the PX aggregate demand bid curve shift as result of removing the impact of the current RMR contracts from both curves, we estimate the hourly increased cost of energy caused by the design of the current RMR contracts in two ways. First, we simply ask the question of how much more it costs to purchase the original PX quantity at PXP, the actual PX price, versus PXPP, the price that removes the impacts of RMR contracts on the bidding behavior of all market participants. This cost is the shaded area in Figure 17, which can be expressed as:

$$\text{Increased Costs Purchasing Actual PX Quantity} = (\text{PXP - PXPP})*\text{PXQ}.$$

The second calculation of the costs of the current type A RMR contracts incorporates an assumption about the convergence of prices in the PX and the other energy markets operating in the ISO system. As described in the following section, prices in the two major energy markets, the PX and the ISO imbalance energy market, have been converging over time. Although in some of the months covered in this analysis, PX and ISO prices fail several tests for convergence, particularly in the NP15 zone (see Borenstein, et al. (1999), an assumption of no arbitrage opportunities between these markets still provides a rough approximation of the relationship between these prices.

Our estimate of the PX price in the absence of the impact of the current RMR contracts can then be used to compute an estimate of the impact of RMR contract A on the cost of all energy purchased in the ISO system. This is done by taking the price change in the PX due to RMR Contract A in a given hour and multiplying it by the total energy consumed in the ISO system. Following Borenstein, Bushnell, and Wolak (1999), we also adjust the ISO energy demand for the level of 'regulatory must-take' energy. This is the amount of energy purchased under various regulatory committments that predate the restructuring of the California market. This includes the output of nuclear power plants and of most independent power producers. Producers of regulatory must-take energy do not earn the PX price for their output, but are rather paid according to the terms specified in their respective regulatory aggreements. We therefore multiply the estimated price difference by the amount of energy purchased under a market-based process. Figure 18 shows this quantity graphically. For each hour we compute

Table 4: Average Hourly Increased Costs Due to Type A RMR Contracts ($ Millions)

Month	**Increased Cost from RMR**			
	Using PXQ		Using ISO Load - Q(MT)	
	Mean	Std. Error	Mean	Std. Error
June	0.06	0.01	0.04	0.01
July	0.16	0.04	0.11	0.03
August	0.22	0.05	0.17	0.04
September	0.14	0.03	0.11	0.02

$$\text{Increased Cost of ISO Load} = (PXP - PXPP) * (ISO\_LOAD - Q(MT))$$

where $Q(MT)$ is that quantity of must-take energy actually produced during that hour and ISO_LOAD is the actual total ISO load for that hour. Table 4 presents the hourly average values of the increased costs of purchasing the original PX quantity and the increased costs of purchasing flexible ISO load for each month.

We also report bootstrap standard error estimates for each of these estimates by extending the bootstrap process described earlier. These are calculated by re-computing the market-clearing price for each hour using the portfolio bids for all market participants adjusted by the bootstrap resample of the RMR factor, $C(i, j, k)$, for that market participant, hour and day combination. The market clearing prices for hours during our sample period for that resample of the $C(i, j, k)$ comprise one resample from the set of predicted hourly PX prices and quantities. We then compute the two average monthly measures of cost savings for this resample of market-clearing prices and quantities. This gives a single bootstrap resample for the two average monthly measures of cost savings for each month of the sample. Repeating this process B times and computing the standard deviation of these bootstrap resamples of the two average monthly measures for each month, yields the bootstrap standard errors given in the table. As might be imagined, this process is extremely computationally intensive, taking over 80 hours of CPU time to compute the 50 bootstrap resamples. Our bootstrap standard errors indicate that the month average hourly cost saving are precisely estimated.

It is interesting to compare the estimated cost impact of RMR with the estimates of the cost of overall market power in the California market given in Borenstein, Bushnell, and Wolak (1999). In that paper, we estimate that the cost of power purchases, using ISO load less must-take generation as the market quantity, was $450 to $650 million above the variable cost of power if all firms had acted as price-takers. Our estimates here of the impact of RMR contracts is roughly 2/3 to half that amount. Although the incentives provided by RMR contracts clearly interact with the ability of firms to excercise market power in a very complex fashion, these results do indicate that type A RMR contracts were a significant contributor to the overall level of market power during 1998.

5 Dynamic Market Considerations

One feature of the California electricity market that distinguishes it from markets such as the E&W pool is the existence of both day-ahead and a real-time hourly spot markets.[23] As described above, the PX operates by far the largest market, in terms of trading volume,and the analysis in the previous section has focused on the bidding behavior of participants in this market. It is important to recognize, however, that trading in other markets does play an important role in determining energy prices in California.

This interaction in part takes the form of inter-market arbitrage of expected prices. Traders that expect the ISO real-time price to exceed the PX price could bid demand into the PX and then not consume it in real time. They would be entitled to the difference between the ISO and PX prices times the demand volume purchased through the PX. Conversely a generator that expects the PX price to exceed the real-time price could commit to sell power into the PX and then not supply it, thereby earning the difference between the PX and ISO prices on that supply quantity.

Recent analysis indicates that arbitrage activities such as these have taken place and that the zonal prices of the PX and the ISO have largely converged over the first year of market operation.[24] Yet the extent of arbitrage, particularly during the first 6 months of market operation, appears to fall short of the theoretical ideal. Table 5 gives the monthly average zonal PX and ISO price for the NP15 and SP15 congestion zones. Institutional barriers, trading restrictions, and the complexity of the market appear to have somewhat limited the effectiveness of this arbitrage.

The extent of inter-market arbitrage is particularly relevent to the question of the impact of RMR contracts on market prices in California. As described above, the protocol of calling upon RMR generation after the day-ahead markets have been run can lead those markets to acquire too much supply, thereby raising the market price above the offer prices of units that are actually still available to supply. If suppliers are also willing to offer that power at the same price in the real-time market, there should be an opportunity to arbitrage the resulting price difference between the day-ahead and real-time prices. In the simplest case of a single RMR unit with an A Contract, demand side arbitrage should be an effective mitigating force on the adverse incentives provided by the RMR contract. If this single unit were expected by all participants to be a must-run unit in a given hour, then all participants would expect that unit to bid an offer price to recover at least its expected RMR earnings from sales into the PX. A consumer with the incentive to acquire power at least cost could therefore underbid its demand by an amount equal to the capacity that it expects will be called outside of the market under an RMR contract. Bids based upon RMR opportunity costs would no longer be marginal, and

[23]Califorina is not unique in this, however. Markets in Norway and Sweden also feature multiple settlement markets (See Wolak, 1997).

[24]See Borenstein, Bushnell, Knittel, and Wolfram, 1999.

Table 5: Average North and South PX and ISO Prices by Month

Month	**Region**	**ISO Price**	**PX Price**
April, 1998	North	22.64	20.49
	South	22.64	20.30
May	North	12.06	9.30
	South	12.06	10.08
June	North	12.25	8.38
	South	12.34	8.38
July	North	32.52	27.73
	South	33.14	27.62
August	North	38.80	45.40
	South	39.96	43.53
September	North	33.97	40.77
	South	33.25	35.13
October	North	27.85	35.29
	South	23.92	27.66
November	North	27.24	30.58
	South	22.92	24.08
December	North	30.43	29.59
	South	26.74	26.13

these generation units would be called under their RMR contracts, rather than scheduled through a day-ahead market. The local market power of these units would thereby be contained to the quantity called by the ISO under the contract.[25]

Unfortunately, as the results of the previous section indicate, several factors appear to have inhibited the ability of demand-side response to completely counteract the incentive effects of RMR contracts. Recall that the RMR quantity called under contract, which in some cases would be the amount that should be under purchased by consumers, is itself endogenous to the outcomes of the day-ahead market. Therefore, even if we assume that all RMR units are under A Contracts, are not part of larger portfolios, and that arbitrage is both costless and effective, the only way such arbitrage could completely offset RMR incentive effects is if all players correctly anticipate the expectations of the other players about the likelihood of RMR calls, and the impacts of those expectations on the bids of those other players. More likely under these circumstances we would see increased price volatility as both consumers and suppliers attempted to anticipate the effects of RMR calls on offer prices. Sometimes consumers would under compensate for these effects, producing higher prices in the PX, and sometimes consumers would overcompensate, producing lower prices in the PX. [26]

In the extreme, purchasing all power in the real-time market would certainly eliminate the effect of RMR contracts on supply bids in day-ahead markets. Given that the nature of competition in the ISO is somewhat different from that in the PX, it is not at all clear that the gains from such a strategy would offset the costs.[27] It certainly was not a strategy adopted by demand bidders in California. One last issue to consider when discussing the impact of RMR contracts on demand bids is the incentives of the firms submitting those bids. Because of trading rules in the PX and ISO, arbitrage opportunities in the California energy market are, for the most part, limited to the actual suppliers and distributors of electrical energy. In particular, a firm that wanted to underbid demand in a day-ahead market must actually have some demand to underbid. The ability to respond to RMR effects is therefore largely limited to the three large distribution utilities, and incentives of these firms are difficult to interpret. On the distribution side, it is not yet clear if the burden of higher energy prices will largely be borne by shareholders or passed on to ratepayers.[28] On the generation side, the incumbent IOUs were, in aggregate, significant suppliers of energy into the PX market during the summer of 1998. Many of

[25]Of course, if the RMR generator anticipates such a demand side bidding response, it may alter its own bidding strategy in the day-ahead markets. We have not investigated what the resulting equilibrium solution, if one exists, would be.

[26]It is important to note that because of the steep upward slope to the aggregate energy supply curve, higher prices tend to be associated with higher quantities. Therefore, suppliers earn higher expected profits from more volatile prices than less volatile prices, assuming both price patterns have the same overall mean value.

[27]For example, the existence of a sequence of forward markets may have stimulated spot market competition among oligopolists along the lines of Allez and Vila (1993). If demand were forced to shift all of its purchases to the last market, the competitive benefits of the sequence of markets would be lost.

[28]While all three firms were subject to a rate-freeze during the summer of 1998, the impact of energy

these generation units were also under type A RMR contracts during this period. These factors combine to create an ambiguous set of incentives for the IOUs with regards to energy prices and RMR contracts.

These ambiguities are reinforced by the empirical results reported in the previous section. These results indicate that, the aggregate response of IOUs to RMR contract levels tends to increase, rather than decrease PX prices. This analysis tries to account for the impact of RMR on both sides of the market by estimating the effect of must-run needs on both supply and demand bids into the PX. The fact that demand side bidding was not able to offset the positive effect of must-run needs on PX prices could indicate that firms were unwilling or unable to arbitrage RMR effects during this time, resulting in a greater (positive) difference between the PX and ISO prices than would have obtained absent RMR contracts. It could also indicate that prices in these markets were in fact arbitraged, and the positive impact of must-run needs on the PX prices also increased prices in the ISO above the levels that would arise absent RMR. We explore these hypotheses further in the following subsection.

5.1 Impact of RMR Contracts on PX and ISO Price Relationship

Our analysis to this point has focused on the price impact of RMR contracts in the PX. In order to investigate the interaction of inter-market arbitrage with the incentive effects of RMR contracts, in this section we consider the impact of RMR contracts on the *difference* between hourly PX and ISO prices. If consumers were able to eliminate the impact of RMR incentives on market prices through arbitrage between these two markets, then we would expect that the level of RMR calls should not systematically related to the difference between prices in these two markets.

The impact of RMR on the real-time price itself is more difficult to interpret. If a considerable amount of must-run generation were called under the RMR contracts, *i.e.* the level of net RMR was high relative to the gross RMR need, then current rules would apparently lead the PX to acquire too much supply. If consumers were anticipating a high level of net RMR however, then they might profitably shift their demand to the real-time market. If actual RMR levels were less than anticipated, this would lead to a relatively greater amount of demand being served by the real-time market thereby leading to higher real-time prices relative to the day-ahead. In general, as we discuss in the previous section, if prices in one market are positively impacted by a regulatory incentive such as those

prices on the overall profitability of these firms depends upon whether or not the transition period during which these firms collect CTC revenue may expire early. A firm that that will likely recover all of its stranded cost within the four-year transition period should, on the distribution side, be largely indifferent to the energy price. Higher energy prices simply mean a delay in the expiration of the transition period, which is passed on to end-use customers.

provided type A RMR contracts, we would expect that the arbitrage of prices with other markets would lead to a positive impact on prices in those other markets also.

Let $PDIFF_{zt}$ be the difference between the PX and ISO prices (*i.e.* the PX price minus the ISO price) in zone z, either NP15 or SP15, for hour t. We estimate the relationship between gross and net RMR calls and this price difference using the following regression equation.

$$\begin{aligned} PDIFF_{zt} &= \alpha_z + \beta_{z1} DA\_ISO\_LOAD_t + \beta_{z2} LOADDIFF_t \ + \\ & \quad \beta_{z3} RMRGROSS_t + \beta_{z4} RMRNET_t + \beta_{z5} RMRAS_t \\ & \quad + \sum_{b=2}^{4} \gamma_{zb} MONTH_b + \sum_{b=2}^{7} \delta_{zb} DAY_b + \sum_{b=2}^{24} \eta_{zb} HOUR_b \end{aligned} \tag{6}$$

We would expect that an important predictor of the difference between PX and ISO prices in an hour is the divergence between expected and actual real-time demand. Therefore we include $DA\_ISO\_LOAD_t$, the ISO's day-ahead load forecast, as well as the difference between the actual ISO load and this day-ahead forecast, $LOADDIFF_t$. The three RMR terms are $RMRGROSS_t$ and $RMRNET_t$, the total (Contract A and B) gross and net MWH of RMR energy called by the ISO in hour t, respectively, and $RMRAS_t$, the MW of capacity called under RMR contracts to provide ancillary services in hour t. We also include dummy variables for each month, day-of-week, and hour-of-day. To demonstrate this apparent inability of market participants to arbitrage completely the RMR amount of gross RMR energy calls during the hour does appear to be simply an artifact of the Summer of 1998, we estimate this model for all hours in the sample period June 1, 1998 to December 31, 1998.

The results of these ordinary least squares regressions are presented in Table 6. We report the White (1980) heteroscedasticity-consistent standard error estimates because of concerns that there are many differences in the conditional volatility of the price difference depending on variables such as the day-ahead ISO forecast of system load. As we would expect, these results show that a higher level of unexpected real-time demand predicts a higher real-time ISO price relative to the PX price. Interestingly, even a higher *forecasted* demand predicts a smaller price difference, indicating a potential inefficiency between these two markets. In both the southern and northern zones, the gross capacity called under RMR predicts a larger price difference between the PX and ISO. It is important to note that these results are not, by themselves, an indication of a market inefficiency, because gross RMR calls are not known until after the PX market closes.

The relationship between the PX and ISO markets is a complex one, and the exact nature of this relationship is an important area of futre study. The impact of RMR contracts on the real-time market also merits further attention. However, the results from the analysis in this section are consistent with the hypothesis that higher levels of

Table 6: Regression Results for PX - ISO Price Differences

Variable	**NP15**		**SP15**	
	Coefficient	**Standard Error**	**Coefficient**	**Standard Error**
CONSTANT	32.2055	4.92203	30.2858	4.86812
DA_ISO_LOAD	-.00179	.00026	-.00162	.00026
LOADDIFF	-.00617	.00050	-.00690	.00053
RMRGROSS	.00406	.00079	.00261	.00074
RMRNET	.00075	.00131	.00184	.00136
ASRMR	-.00253	.00261	.00044	.00263
July	4.7603	1.1114	5.9186	1.0919
August	-6.3180	2.2050	-4.4800	2.3140
September	-11.3608	1.7171	-6.9645	1.7183
October	-22.9919	2.5023	-13.7449	2.4195
November	-16.7769	2.1292	-9.6098	2.0815
December	-10.2475	1.5481	-5.9735	1.5642
Monday	4.6230	1.4754	3.1429	1.4654
Tuesday	13.3597	1.3487	10.6377	1.3557
Wednesday	9.9508	1.3500	8.1276	1.3372
Thursday	8.1813	1.2827	7.1413	1.2721
Friday	10.0268	1.2271	9.1230	1.2120
Saturday	5.4070	1.0192	4.9547	1.0267
Hour 2	-1.2408	0.8666	-1.6923	0.9516
Hour 3	-2.6458	0.8943	-3.2238	0.9913
Hour 4	-3.0124	0.8958	-4.0352	0.9998
Hour 5	-2.2096	0.8570	-3.0310	0.9875
Hour 6	0.9130	1.2250	-0.2520	1.0592
Hour 7	1.3171	1.2841	0.9059	1.2633
Hour 8	0.2815	1.5904	1.6397	1.5898
Hour 9	0.7979	1.8967	1.8109	1.8331
Hour 10	2.9627	2.1349	2.4105	2.0840
Hour 11	5.2853	2.2372	3.9099	2.2427
Hour 12	3.0637	2.4603	2.3101	2.4731
Hour 13	6.3337	2.5969	4.8750	2.5924
Hour 14	6.3282	2.7406	4.6955	2.7287
Hour 15	6.9649	2.7848	5.9714	2.7441
Hour 16	3.5585	2.7882	2.8964	2.8302
Hour 17	7.2442	3.0086	5.9304	3.0036
Hour 18	5.2404	3.1570	3.1645	3.1327
Hour 19	6.3301	2.9388	4.7396	2.9341
Hour 20	5.5722	2.6601	4.2969	2.6278
Hour 21	7.8632	2.3987	5.8447	2.3585
Hour 22	4.3108	1.8637	2.5367	1.9020
Hour 23	2.6878	1.3079	1.5213	1.3566
Hour 24	1.9052	0.9549	0.1238	1.0418

Note: White (1980) heteroscedasticity-consistent standard error estimates reported.

RMR, or higher levels of local market power, lead to higher prices in the PX day-ahead market.

6 Conclusions

In California, as in most electric systems around the world, transmission constraints and reliability requirements convey a significant amount of market power over local areas. Recognizing this fact, market designers in California put in place reliability must-run contracts, which were intended to be invoked to ensure production from necessary generators, even when their bids exceed the regional market price. However, the terms and conditions of these contracts incented essentially the same behavior from generators that the local market power the contracts were designed to mitigate.

In this paper we have focused on the type A RMR contracts, the form of contract that applied to most of the must-run generators during the summer of 1998. These contracts paid generators a portion of their sunk and fixed costs, as well as their operating cost for each MWh produced under instruction from the ISO. These payments often far exceeded the marginal cost of these generators. Generators were only eligible for these payments if they were not already schedued to produce power through one of the day-ahead markets. Generators were thereby incented to base their bidding strategies in the day-ahead markets upon their expected RMR revenues, rather than their marginal cost.

We analyzed the bidding behvior of all the participants in the day-ahead energy market of the PX and found that the type A RMR contracts significantly impacted bidding behavior into the PX during the Summer of 1998. During periods expected to have high type A RMR contract calls, which tended to coincide with hours when ISO load was forecasted to be high, bid prices where higher as a result of the profit-maximizing incentives provided by these contracts.

Although we study a market where a regulatory mechanism, the RMR contract, caused distortions in bidding behavior, we believe that this phenomenon is likely not limited to the Calfornia market, nor is it dependent upon such contracts. Wherever transmission constraints create an opportunity to earn local monopoly rents, it is reasonable to expect that these opportunities would influence bidding strategies. Whenever a generator with a bid based upon the opportunity for local monopoly rents could be the marginal bidder in a regional market, the potential for the leverage of this local market power exists. The analysis of the impacts of local market power on electricity markets, and the role of market rules, transmission pricing, and transmission rights, in determining these impacts, is therefore an important line of future study.

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Because this combination local reliability and local monopoly problem afflicts most electricity markets to some degree, it is important to consider the role that a regulatory instrument such as the RMR contract could play in mitigating the problem. Properly implemented, RMR contracts can effectively isolate local market power and make the allocation of local monopoly rents a transparent process in which regulation can play a role. Recent revisions to the RMR contracts in California helped to move that market closer to this goal.[29] Both the type A and type B Contracts have been eliminated, to be replaced by a single contract type that more closely resembles the original conception of the RMR contract. For the provision of energy under ISO must-run instructions, generators will recieve only a payment equal to their marginal cost. Must-run generators will also receive a monthly fixed payment. Unlike the B Contract, these new contracts will not require any rebate of operating profits. The basis for the fixed payments is still a subject of some dispute, but they will no longer include sunk capital costs. Any local rents captured by these generators have thereby been transfered to a side payment that is independent of market outcomes. This eliminates the opportunity cost of selling power in the regional market.

The most contentious remaining issue yet to be resolved in the redesign of the RMR contracts is the protocol for the dispatching must-run units. The current practice of operating the day-ahead markets before identifying must-run units is to continue at least through the summer of 1999. Absent intentional and coordinated under-bidding of demand by large consumers, this means that the PX will continue to clear its market at too high a quantity. An alternative proposal is to identify must-run generators before the operation of the day-ahead markets, and give those generators the option of earning their contract rate or the yet to be determined PX price. Under this proposal, must-run generators that elected to earn the PX price would bid zero into the PX, effectively becoming price-takers.

The full scope of these reforms has yet to be implemented, and the impact of the changes that are made will need to be assessed in the context of a broad set of changes underway in the California market. Nonetheless, estimates of the effect of RMR contract reform have already been requested by the Federal Energy Regulatory Commission. The outcome of this reform process will play an important role in determining the future competitiveness of the California market, and, if sucessful, could help provide useful lessons for dealing with problems of local market power in electricty markets around the world.

[29] For a more detailed discussion of the issues relating to RMR contracts, and the proposals for their reform, see Wolak and Bushnell (1999).

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Appendix: Bootstrap Procedure to Compute Standard Errors

This appendix describes the bootstrap procedure we use to compute the standard error estimates for the sample RMR factors in Tables 4.2 and 4.2 and the monthly average hourly cost of type A RMR contracts in Table 4. To describe our procedure, consider the three equation system composed of firm i's price bid function and the two equations it uses to forecast RMROWN and RMROTHER:

$$y_{ijk} \;=\; X'_{ijk}\Gamma_i \;+\; \beta_{i1}RMROWN_{ijk} \;+\; \beta_{i2}RMROTHER_{ikj} \;+\; \eta^1_{ijk}$$

$$RMROWN_{ijk} \;=\; W_{ijk}\prime\Lambda_{1i} \;+\; \eta^2_{ijk}$$

$$RMROTHER_{ijk} \;=\; W_{ijk}\prime\Lambda_{2i} \;+\; \eta^3_{ijk}$$

where W_{ijk} is the vector composed of the 24 values of DA_ISO_LOAD, $(DA\_ISO\_LOAD)^2$, $(DA\_ISO\_LOAD)^3$ for day k and the elements of X_{ijk} excluding $DA\_ISO\_LOAD_{ijk}$ and its squares and cubes. Define the vector $e_{ijk} \;=\; (\eta^1_{ijk}, \eta^2_{ijk}, \eta^3_{ijk})\prime$. In our bootstrap procedure we assume that the e_{ijk} are uncorrelated across j and k, but we allow for the fact that e_{ijk} and $e_{\ell ij}$ may be correlated, meaning that the unobserved portion of firm i's bid price equation and the unobserved portions of the equations it uses to predict RMROWN and RMROTHER during hour j of day k may be correlated with these three unobservables for firm ℓ in the same hour and day.

Call instrumental variables estimate of the bid price equation and the ordinary least squares estimates of the two RMR equations for each firm $\hat{\Gamma}_i$, $\hat{\Lambda}_{1i}$, and $\hat{\Lambda}_{1i}$ For each firm i, construct estimates of e_{ijk} for all j and k as:

$$\hat{\eta}^1_{ijk} \;=\; y_{ijk} \;-\; X'_{ijk}\hat{\Gamma}_i \;-\; \hat{\beta}_{i1}RMROWN_{ijk} \;-\; \hat{\beta}_{i2})RMROTHER_{ikj}$$

$$\hat{\eta}^2_{ijk} \;=\; RMROWN_{ijk} \;-\; W_{ijk}\prime\hat{\Lambda}_{1i}$$

$$\hat{\eta}^3_{ijk} \;=\; RMROTHER_{ijk} \;-\; W_{ijk}\prime\hat{\Lambda}_{2i}$$

Define $\hat{e}_{ijk} \;=\; (\hat{\eta}^1_{ijk}, \hat{\eta}^2_{ijk}, \hat{\eta}^3_{ijk})\prime$. For all firms, i=1,...,8, sort the

$$2928 \;=\; 24 * (30 + 31 + 31 + 30) \; observations$$

(24 hours multiplied by the total number of days in the sample) on $\hat{e}_{ijk}$, X_{ijk} $RMROWN_{ijk}$, $RMROTHER_{ijk}$, and W_{ijk} in chronological order. Sample with replacement 2928 times from a discrete-valued random variable on the integers from 1 to 2928. Call this random

variable N_{nb}, where the n^{th} realization of this random variable gives integer between 1 and 2928 that is associated with observation number n in the ordered sample. Because the observations are sorted in chronological order, associated with each integer from 1 to 2928 is a unique hour j and day k during our sample period. Define $(s(N), t(N))$ as the (j, k) pair associated with observation N. In terms of this notation, $(s(N_{nb}), t(N_{nb}))$ gives the resampled hour,$s(N_{nb})$, and day, $t(N_{nb})$, associated with hour j and day k for bootstrap resample b. For each firm i, and value of N_{nb}, $n = 1, ..., 2928$, compute

$$y_{ijk}^b \;=\; X_{ijk}\prime\hat{\Gamma}_i \;+\; \hat{\beta}_1 RMROWN_{ijk} \;+\; \hat{\beta}_2 RMROTHER_{ikj} \;+\; \hat{\eta}_{is(N_{nb})t(N_{nb})}^1$$

$$RMROWN_{ijk}^b \;=\; W_{ijk}\prime\hat{\Lambda}_{1i} \;+\; \hat{\eta}_{is(N_{nb})t(N_{nb})}^2$$

$$RMROTHER_{ijk}^b \;=\; W_{ijk}\prime\hat{\Lambda}_{2i} \;+\; \hat{\eta}_{is(N_{nb})t(N_{nb})}^3$$

This generates a resampled series of y_{ikj}, $RMROWN_{ijk}$ y_{ikj}, $RMROWN_{ijk}$ for each firm. Now apply the original estimation procedure to the resulting three equation system for each firm with y_{ikj}^b, $RMROWN_{ijk}^b$ and $RMROTHER_{ijk}^b$ in place of the original data on y_{ikj}, $RMROWN_{ikj}$, $RMROTHER_{ijk}$ in the first equation and $RMROWN_{ikj}$ and $RMROTHER_{ijk}$ in the second and third equations. This yields $\hat{\Gamma}_i^b$, $\hat{\Lambda}_{1i}^b$, and $\hat{\Lambda}_{1i}^b$ for each firm for bootstrap resample b. Repeat the above procedure for B draws of length 2928 from N_{nb}. This gives B values of $\hat{\Gamma}_i^b$, $\hat{\Lambda}_{1i}^b$, and $\hat{\Lambda}_{1i}^b$.

To compute the standard error for $\bar{C}_i^m(\hat{\Delta}_i)$, given in Table 4.2, we compute the value of $\bar{C}_i^m(\hat{\Delta}_i^b)$ for each bootstrap resample of $\hat{\Delta}_i^b$, the vector composed of $\hat{\Gamma}_i^b$, $\hat{\Lambda}_{1i}^b$, and $\hat{\Lambda}_{1i}^b$. Computing the standard deviation of the B resamples of $\bar{C}_i^m(\hat{\Delta}_i^b)$ yields the bootstrap standard error estimate of $\bar{C}_i^m(\hat{\Delta}_i)$. Note that because we use the same draw of N_{nb} to determine the values of the $\hat{e}_{ijk}$ resampled for all firms for hour j of day k, this preserves the contemporaneous correlation in the e_{ijk} across firms in the bootstrap procedure.

To compute the standard error for the sample average hourly means of the RMR factors for the three eight hour blocks of during each day given in Table 4.2, we repeat this same procedure of computing this sample average hourly mean of the RMR factors for the relevant eight hour block for each resample of the RMR factors. Then computing the standard deviation of these resampled means, yields the bootstrap estimate of the standard error for that sample average hourly mean.

Finally, to compute the standard error estimate of the cost of type A RMR contracts given in Table 4, requires an additional extremely computationally intensive step. For each resampled value of the RMR factors for all hours, days and firms, we apply the process of computing the counterfactual, no RMR A Contract, predicted PX price and quantity for each hour and day during the sample. From these prices we then compute the two measures of average hourly costs given in Table 4. This gives one bootstrap resample of these average hourly costs. We then repeat this procedure for all the B resamples of the PX factors. The standard deviation of these resampled average hourly costs, give the bootstrap standard error of the average hourly costs of type A RMR contracts given in table 4.

FIGURE 1

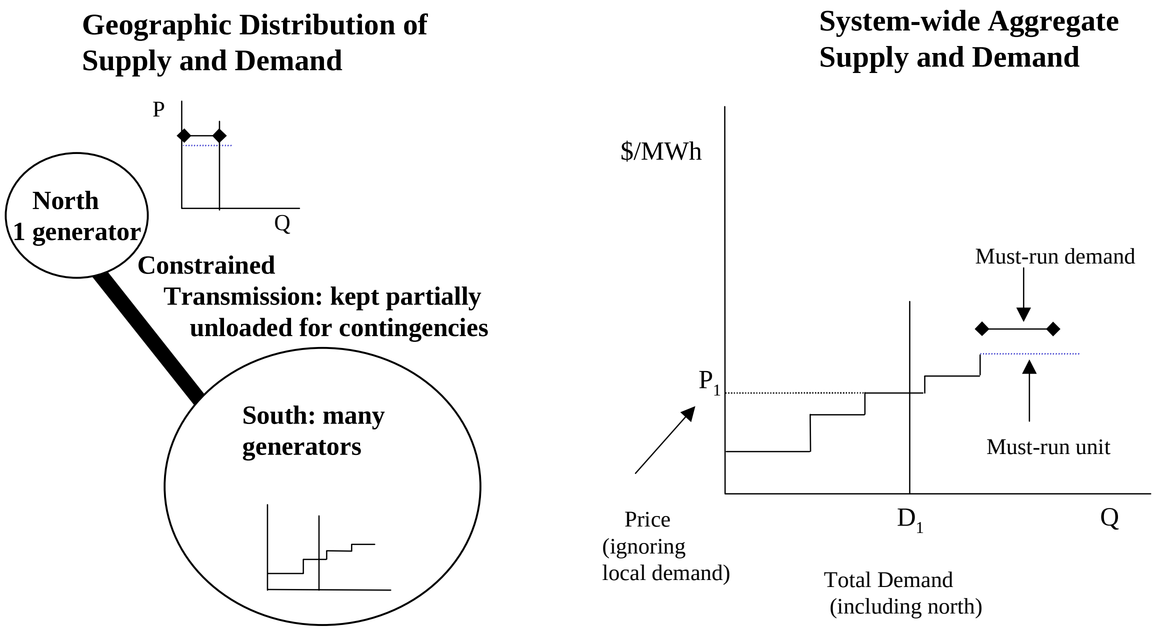


FIGURE 2

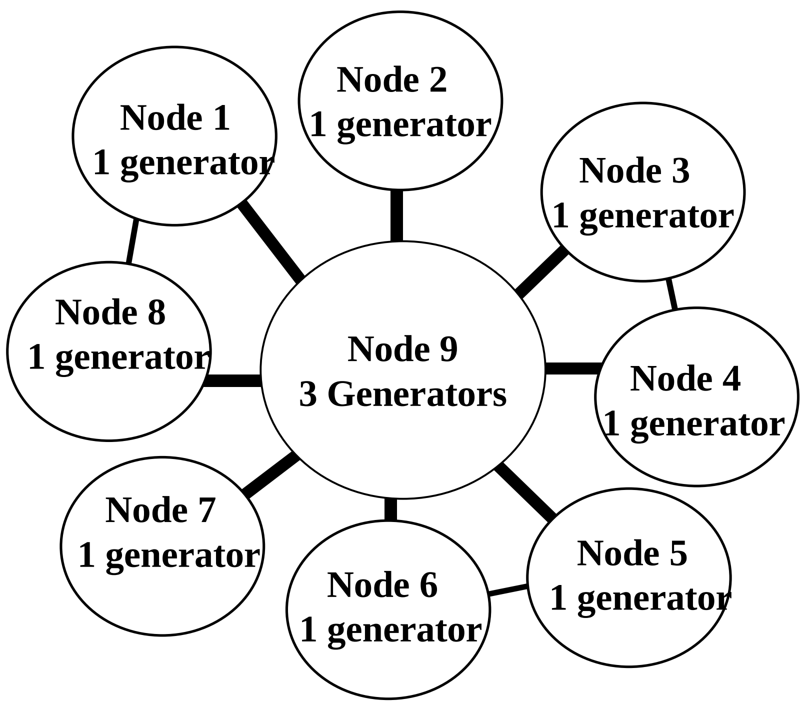


FIGURE 3

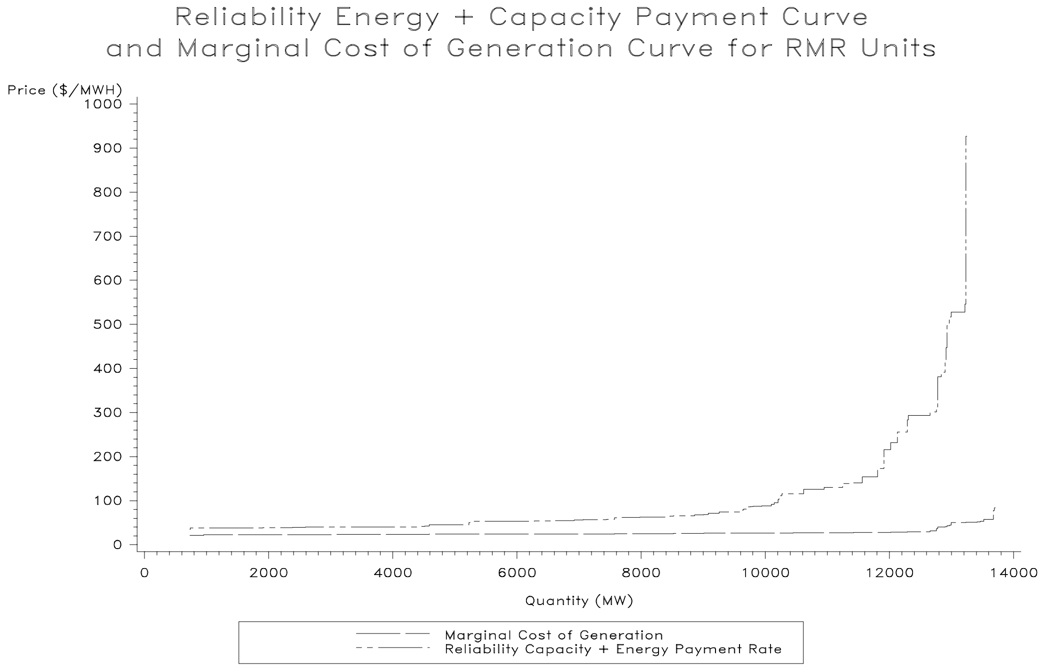


FIGURE 4

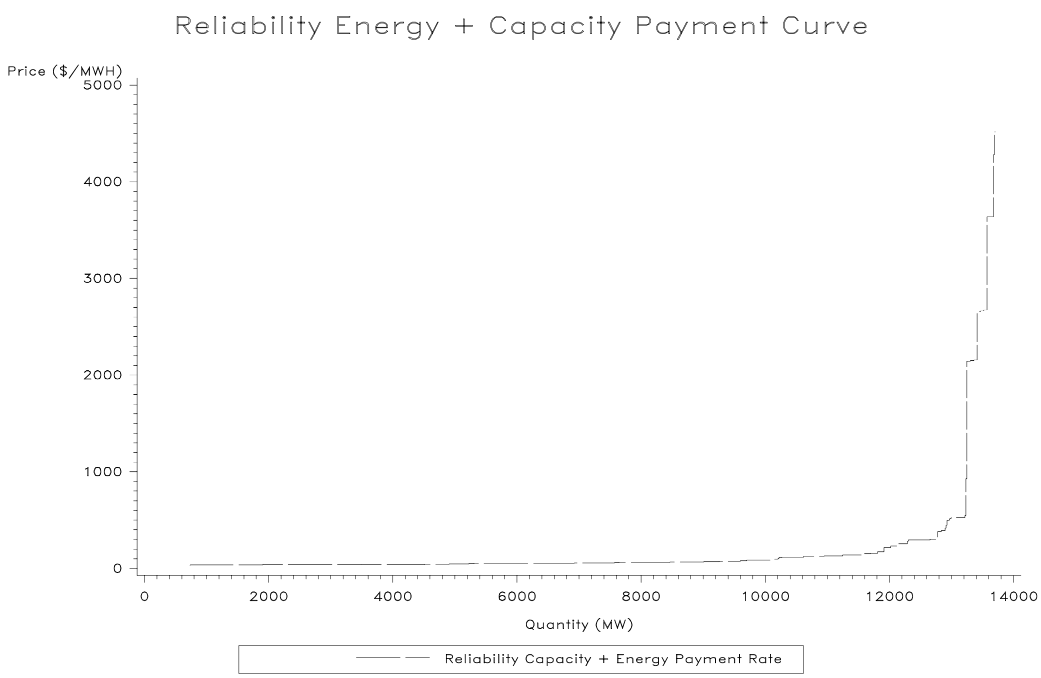


FIGURE 5

Market Timing

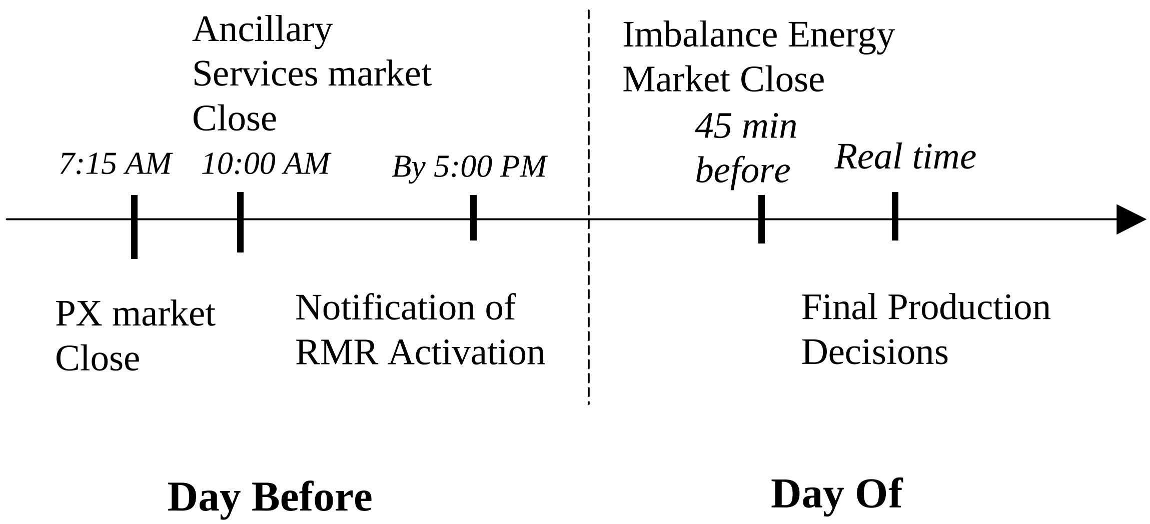


FIGURE 6

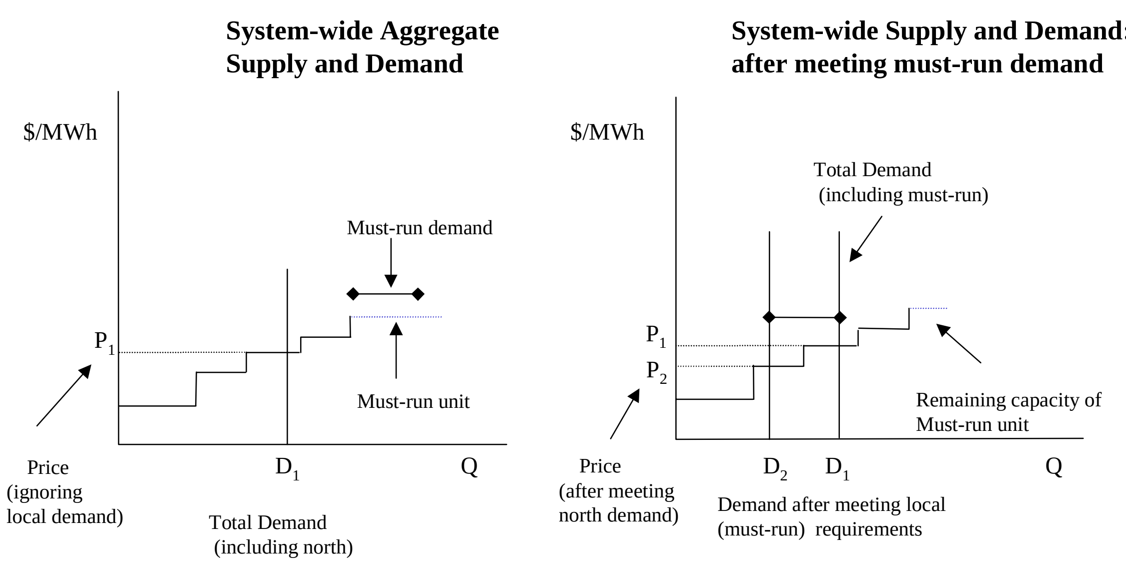


FIGURE 7

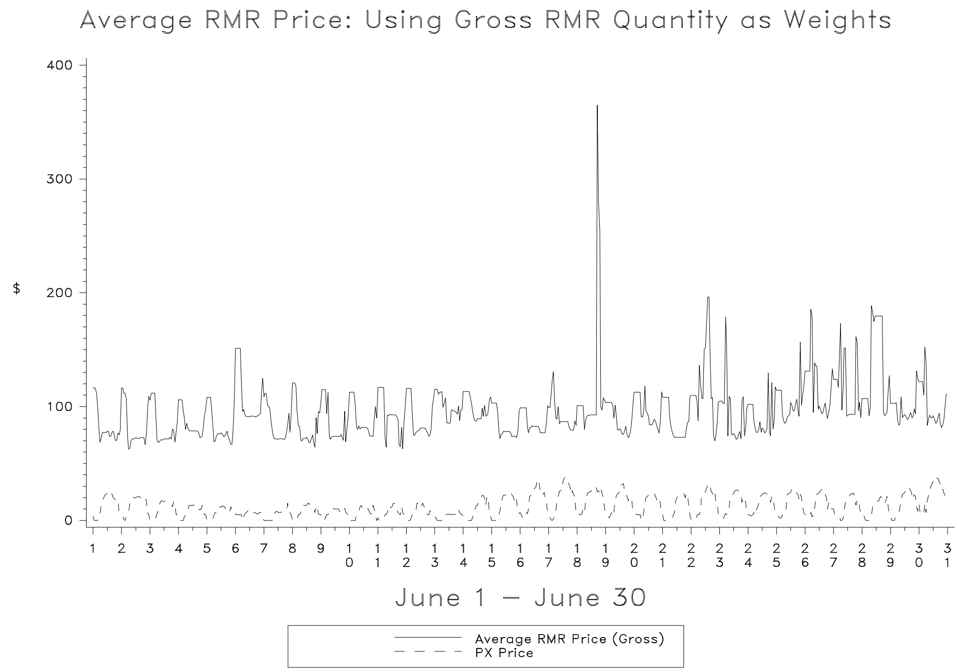


FIGURE 8

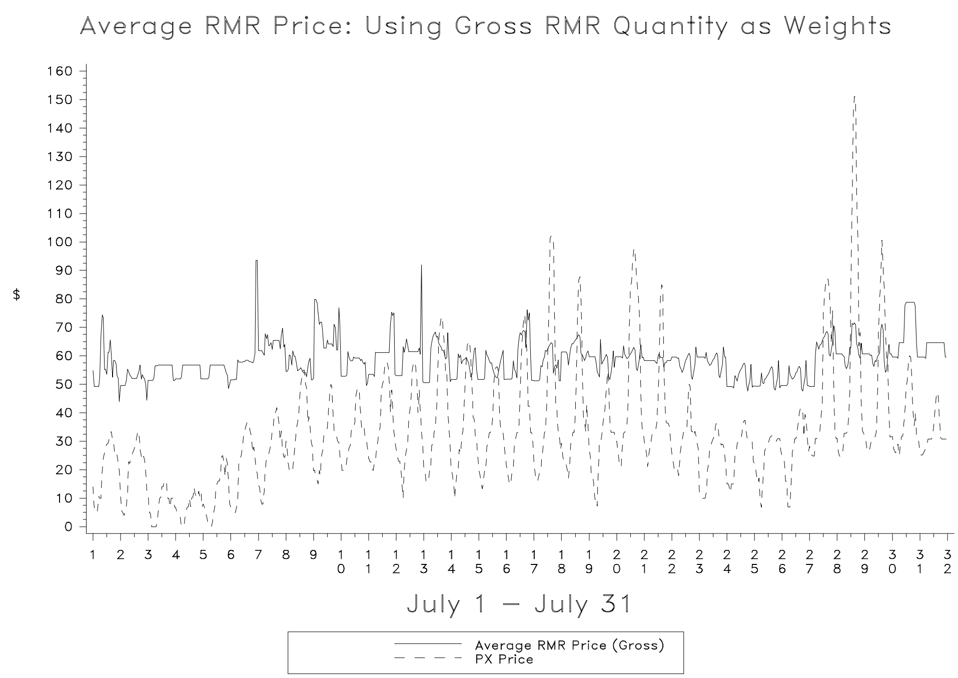


FIGURE 9

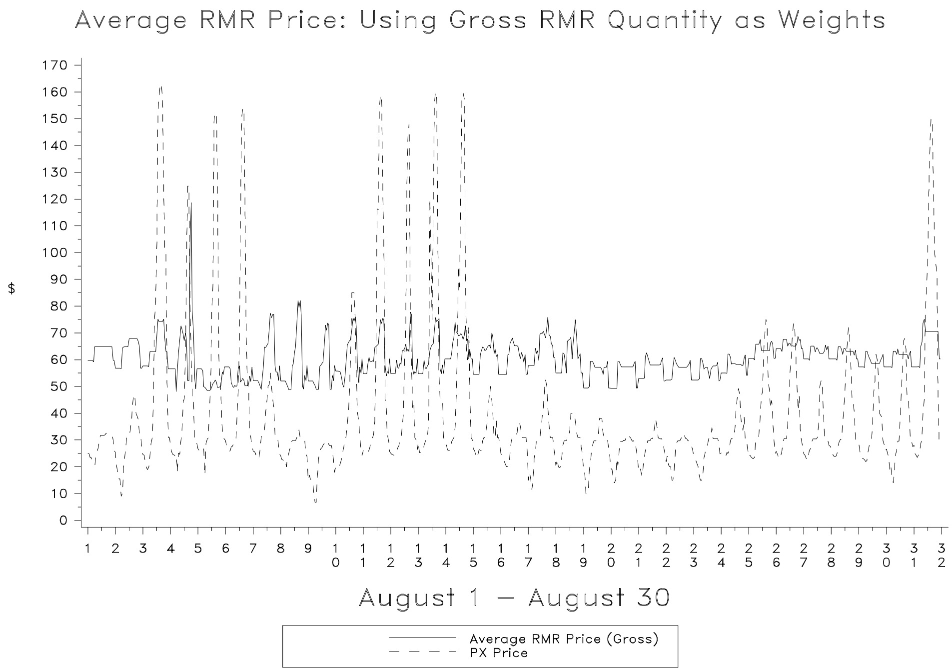


FIGURE 10

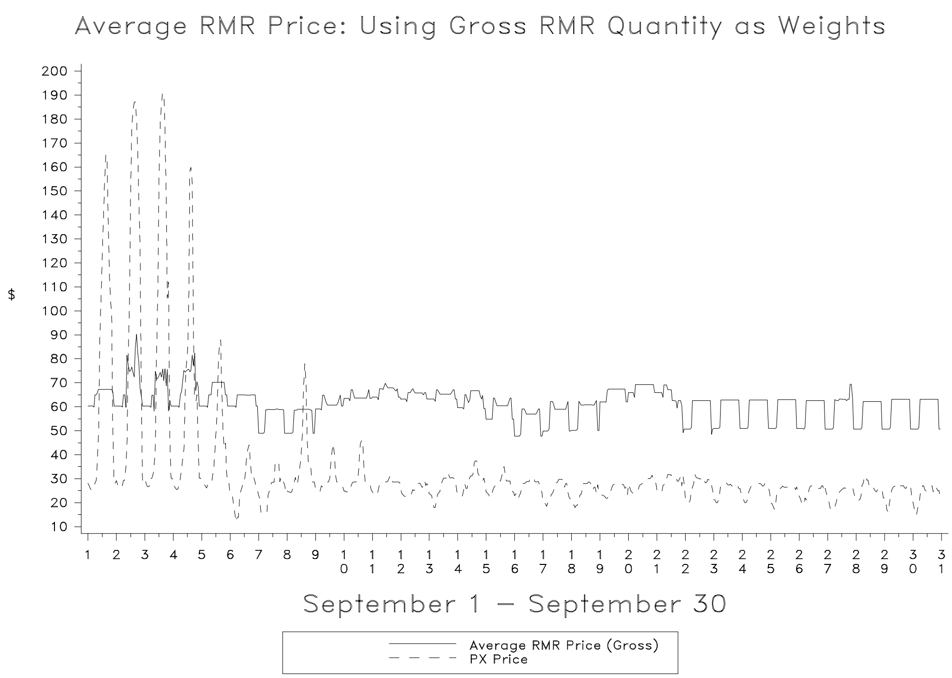


FIGURE 11

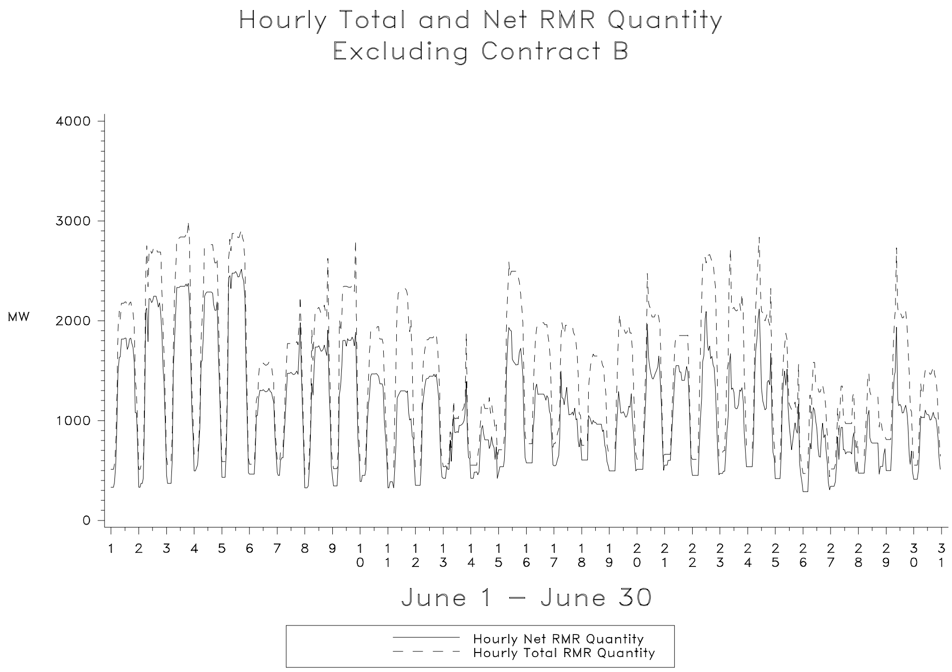


FIGURE 12

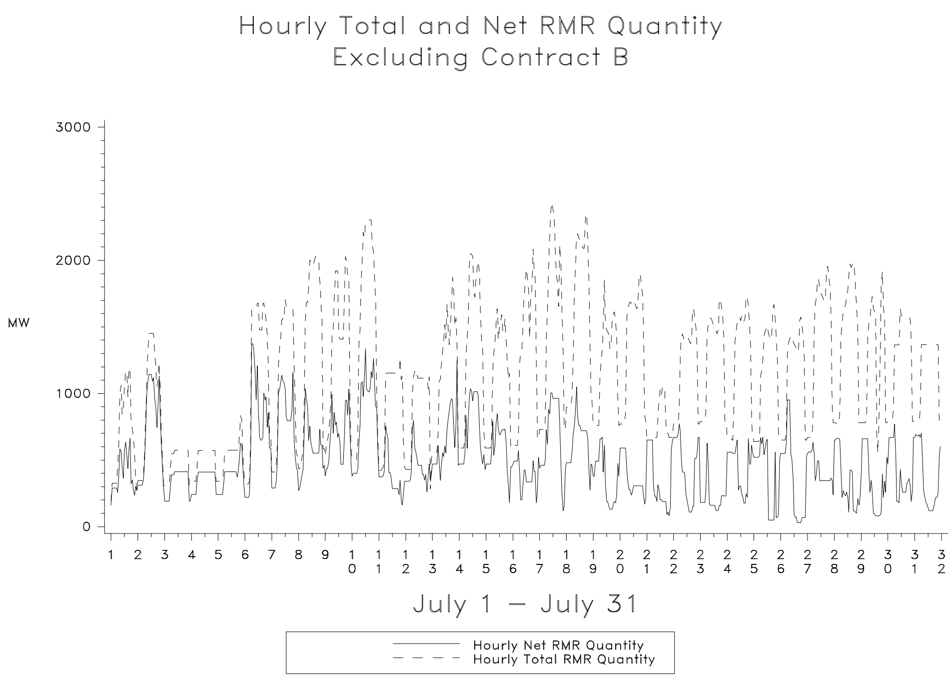


FIGURE 13

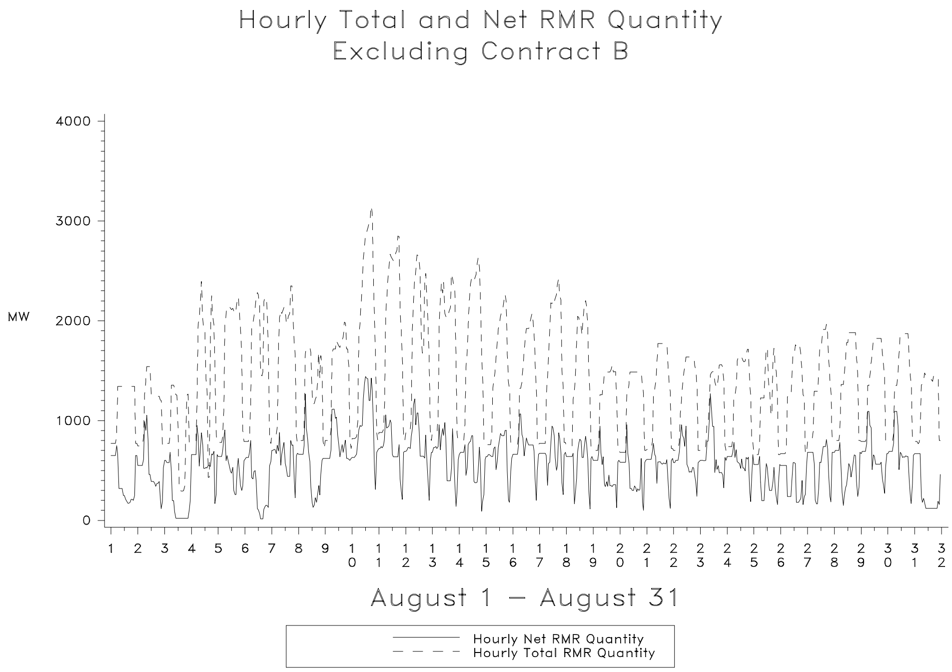


FIGURE 14

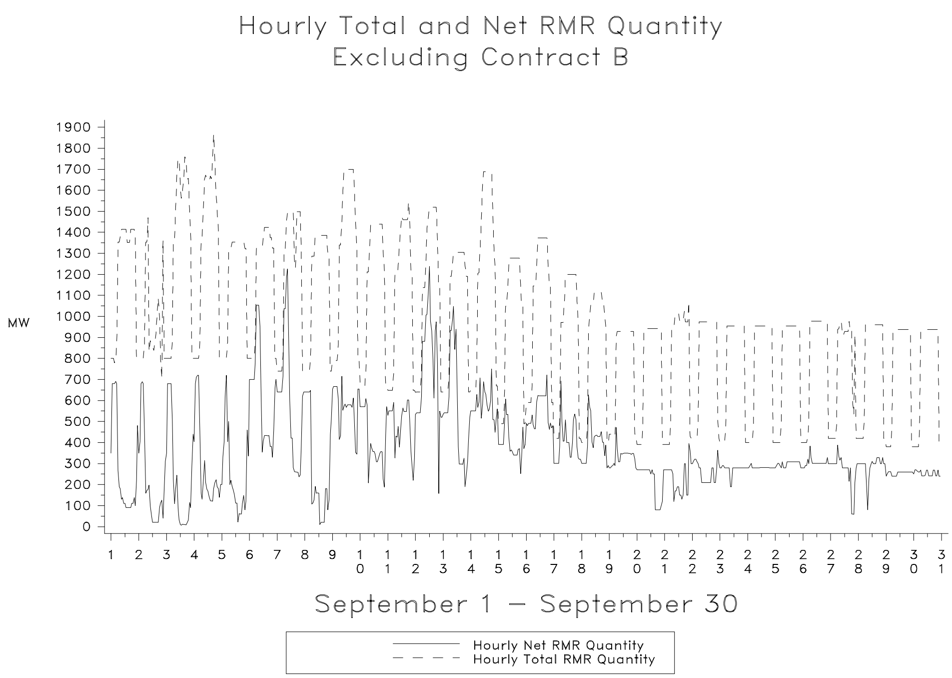
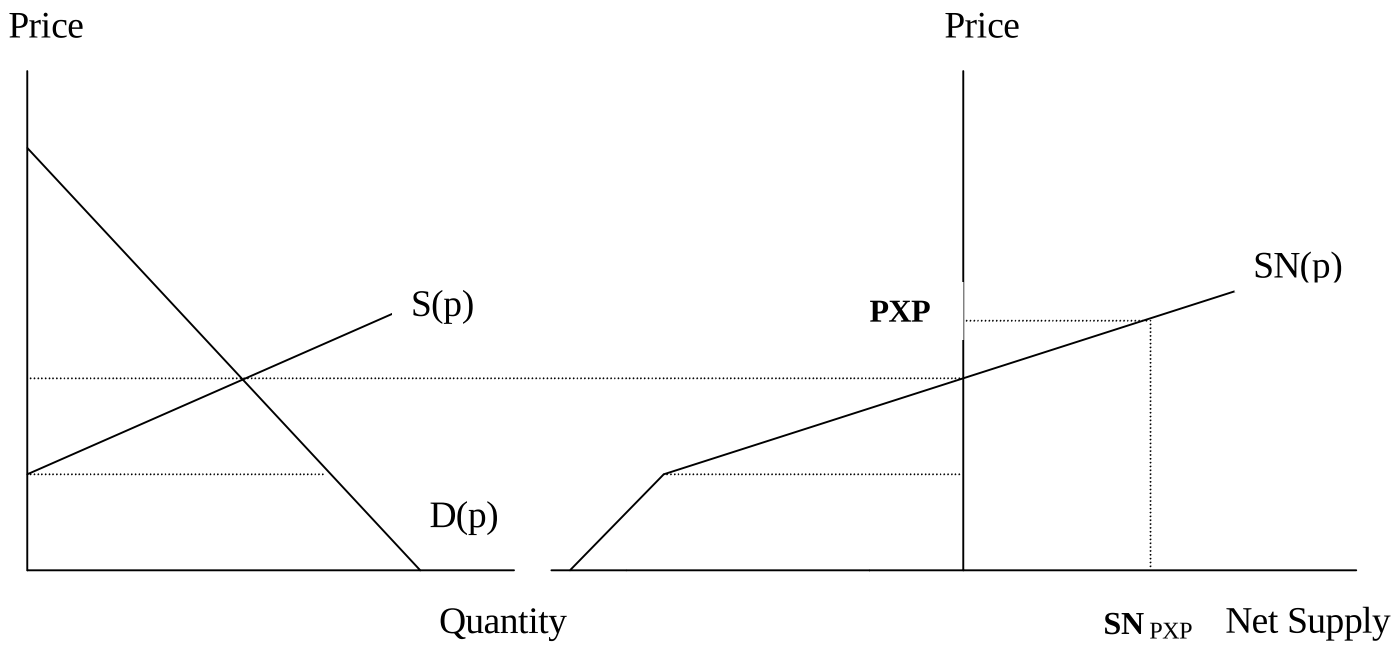


FIGURE 15:



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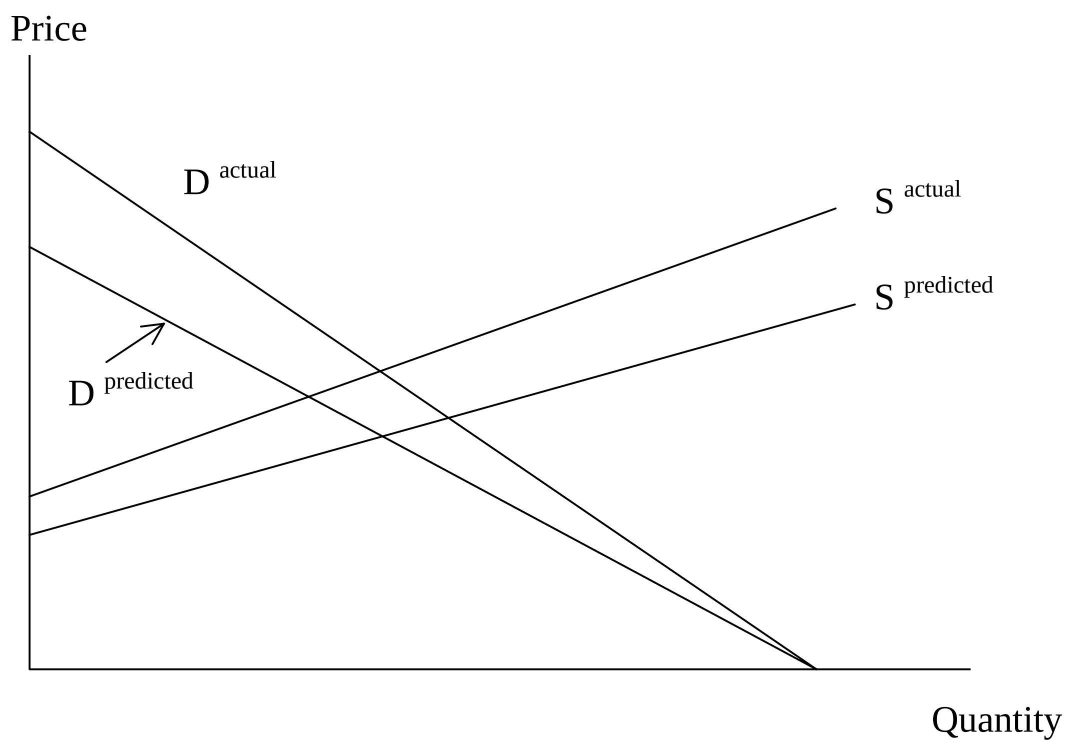

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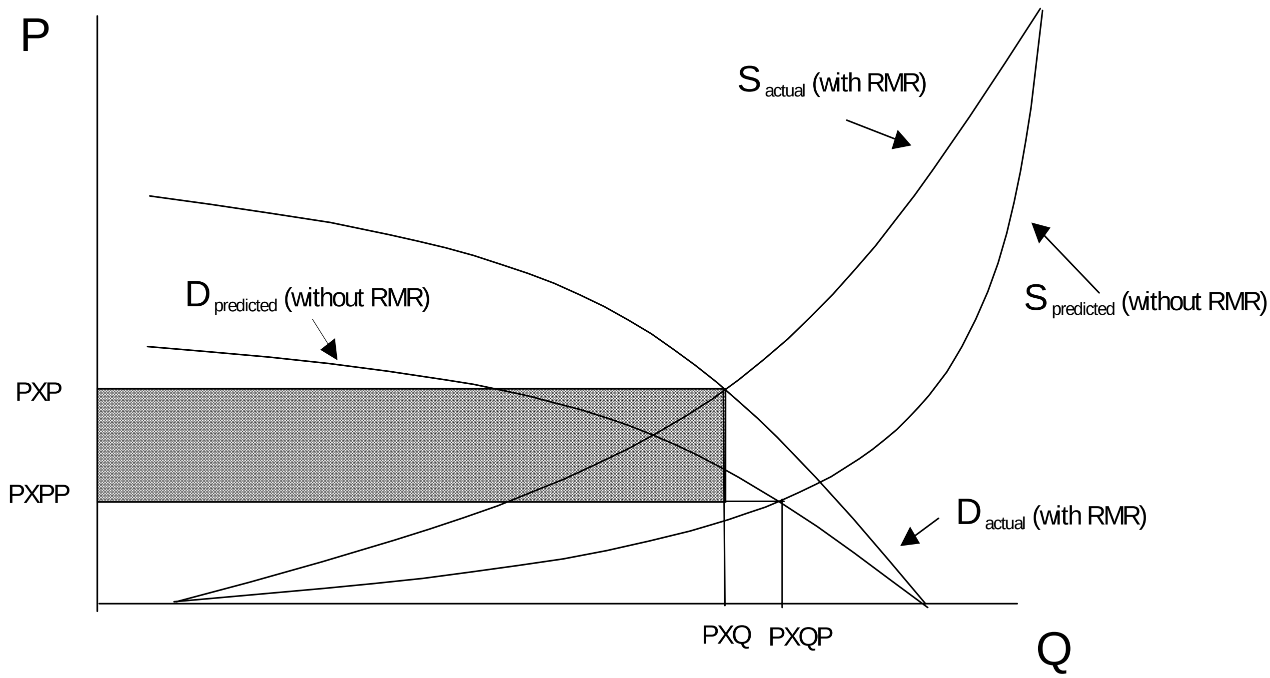

FIGURE 18: