Reliability Must-Run Contracts for the California Electricity Market

by

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1 Introduction

In its August report on the operation of the ancillary service markets of the ISO, the Market Surveillance Committee (MSC) expressed serious concern over the impact of reliability must-run (RMR) contracts on the competitiveness of these markets. These concerns were echoed by several stakeholders in their comments on the MSC report. There is concern that RMRs, which were designed to mitigate the impact of the local market power that is enjoyed by certain generation units, are instead being leveraged by their owners to exacerbate market power on a state-wide level. The impacts of this behavior have been felt both in terms of increased contract payments from the ISO to RMR generators and in terms of increased market prices for both energy and ancillary services.

In discussing market power, we apply the standard economic definition: the ability to set market prices above the marginal cost of production.[1] This is not to say that we expect prices always to equal marginal cost, or that we necessarily define marginal cost to include only short-run fuel costs. Some degree of market power is present in most all markets.[2] However, the degree to which prices do exceed marginal cost is a standard benchmark for judging the relative competitiveness of an industry. Policy makers must therefore make judgements about what levels of market power are tolerable relative to the costs associated with reducing market power. Such judgements depend upon many factors and must be considered on a market-specific basis. The electricity industry is particularly vulnerable, at least in the near future, to supplier market power because of, among other factors, the lack of price-responsive demand, very costly storage, binding short-run capacity constraints, and the need for a constant balance of supply and demand.

Ongoing negotiations to revise the RMR contracts have been underway for some time. The original goals of the ISO in these negotiations had been to reduce the fixed payments inherent in the original contracts and to encourage generation units eligible for RMR to rely more upon market revenues. At the same time, the ISO also sought not to limit its future options for dealing with local market power, including the entry of new supply capacity and the addition of load-based alternatives. These negotiations yielded a new contract structure (dubbed 'son of B') that would have provided generators with a menu of trade-offs between their level of guaranteed fixed payments and the amount of market revenues that they are allowed to keep. Generators would have also retained the option of selecting the 'A' form of contract that features considerably higher RMR variable payments, but no guaranteed fixed payments.

By reducing the level of guaranteed fixed payments these new contracts would, other things equal, reduce the fixed payments made by the ISO to RMR generators. However, the net effect of these changes on the total payments made under RMR contracts depends

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[1] See, for example, Viscusi, K., Vernon, J., and J. Harrington, *Economics of Regulation and Antitrust*. MIT Press, Lexington, MA. 1995.

[2] Market power is not, however, a necessary precondition for the recovery of fixed costs.

upon how these contracts influence the bidding and scheduling practices of generators. Furthermore, it appears that the *indirect* effect of RMR contracts on the bidding behavior of market participants and on the overall operation of the PX and ISO markets can as large as any *direct* impact that may result from changing specific, fixed or variable payments. In this report, we will argue that it is more prudent to shift all RMR compensation, except payments for short-run fuel and variable operating and maintenance costs, to fixed payments in order to minimize the impact of must-run units on the operation of the broader energy and ancillary services markets. The contract forms being considered in the most recent RMR negotiations more closely match this general format.

Since its August report, the MSC has continued with its analysis of the California electricity markets and, given the time frame of the RMR negotiations, has focused particularly on issues relating to RMR contracts. This effort includes an analysis of the 'must-run' contracting approach and its overall impacts on several facets of the California market. An assessment of the potential role that RMR contracts have played in the bidding behavior of market participants is a key component of this analysis. In this report, we concentrate on the question of bidding behavior, particularly in the PX. We focus on the PX because it is easier to track to the payments made to providers of energy, rather than ancillary services, under RMR contracts. As noted by various by various respondents to the August MSC Report, there are considerable across-generator differences in how generators are compensated for providing ancillary services under the terms of their RMR contract. It is therefore easier to examine the opportunity costs that RMR contracts create for generators supplying energy.

Figure 1d of the March 25, 1999 MSC report shows that the daily cost of ancillary services payments has averaged approximately 15% of total day-ahead energy costs over the first year of operation of the California market. Given an estimate of the impact of RMR contracts on the PX day-ahead energy market, this percentage can be used to compute a rough estimate of the impact RMR contracts have on prices in the ancillary services markets. Rather than attempt to perform this calculation, we report our estimates only for the energy markets.

Since the initial draft of this document was prepared in December of 1998, we have made two presentations of these results to participants in the RMR negotiation process, on December 8, 1998 at the Federal Energy Regulatory Commission and on March 8, 1999 at Pacific Gas and Electric in San Francisco. The analysis presented here attempts to respond to the comments and suggestions we received from members of the audience at both presentations.

2 Must-run Contracts and Local Market Power

A significant contributor to the worldwide momentum towards competitive restructuring of electricity markets has been the general 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 geographic regions, the limits of transmission capabilities in most electric systems often make necessary the operation of certain, specific generation units to meet localized consumption or reliability needs.

This 'must-run' status of certain generation units endows them with a special form of local market power. If a single, market-wide price was determined through an 'open' market process that ignored these localized needs, some of these critical 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 these must-run units were instead determined through a market process held at every location in the network, these local generators could dictate prices to their captive customers. These facts are widely recognized, and experience in early operation of the electricity market of the United Kingdom demonstrates just how severe a problem this can become.[3] In order to combat this local market power, policymakers have developed a variety of instruments, including location-specific price caps that can be made contingent on load or supply conditions.[4]

The supply and demand conditions leading to a must-run 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.[5] 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 either a system-wide, or location specific market clearing prices.

In California, the problem of local market power is complicated by the protocol of 'self-dispatch.' Unlike 'tight' power pools such as the PJM pool, in a self-dispatch market, the generators themselves make the vast majority the decisions about the output levels of their units. All advance commitments in the California market are 'financial,' rather than 'physical' commitments. Deviations from day-ahead and hour-ahead schedules must be made whole through purchase or sales from a real-time spot market, but no further penalties are applied. Therefore, in California, absent some kind of contract, the ISO has no means to compel generators to provide power when it is needed

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[3] See Office of Electricity Regulation, "Report on Constrained-On Plant," Birmingham,U.K., 1992.

[4] For a brief analysis of such a mechanism that was proposed for the PJM pool, see P. Joskow, and R. Frame. "Report on Horizontal Market Power Analysis," PJM supporting companies request for market-based rates, FERC docket No. ER-3729-000, pages 126-130.

[5] This is an extremely simplified example meant only to illustrate the economics behind the must-run problem. The criteria that have been used to determine must-run needs require that system stability be maintained in the event of various 'contingencies,' such as forced outages of generation units, transmission lines, or transformer banks. See California ISO, "Five-year reliability must-run technical study of the ISO-controlled grid." Grid Planning Department. May, 1998.

for reliability purposes.[6] Due to the above concerns, a binding contract to provide must-run services under certain conditions was adopted as the mechanism of choice for dealing with the local market power problem.

2.1 Reliability Must-run Contracts

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,[7] 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, thereby ignoring local grid constraints. If market prices were instead set at each location, this compensation would not be necessary because these units would be setting their own price. Of course, in the absence of some other form of regulatory restraint, the potential for market power is too great to expect that location-specific prices would be anywhere near competitive levels.

Thus, concerns over local market power prevented the implementation of localized energy prices, and thereby created the need for a contract to compensate generators who are forced to produce when the (non-localized) energy price is below their cost. Contrary to the comments of some stakeholders[8] the need for an 'instrument to ensure system reliability and stability,' is therefore created by the need to counteract local market power. These two goals are interrelated, not distinct. They are, in the words of Jurewitz and Walther, "two sides of the same coin."

2.1.1 Contract Rates

For the purposes of our discussion of RMR rates and incentives, we will rely upon the following definitions of costs. *Variable costs* are costs directly caused by the operation of the generation unit, and thereby vary with the total output and hours of operation of a unit. *Marginal cost* is the additional cost necessary to produce an additional unit of output. *Fixed costs* are costs that are periodically incurred in order for the generation unit to continue to be able or available to operate. They are unrelated to the amount of electricity produced by a plant within the period over which the costs are incurred, but can be considered a 'going forward' cost associated with the continued operation of the plant. *Sunk* costs are payments or obligations that have already been incurred, and will remain whether or not the plant continues to operate. The capital costs

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[6] It is our understanding that the ISO does possess 'emergency' powers to compel the operation of a generation unit if it judges such operation to be necessary to maintaining the integrity of the grid.

[7] Jurewitz J. and R. Walther (1998) "Must-run generation: Can we mix regulation and competition successfully?" *The Electricity Journal*, 10(10): 44-55.

[8] See for example "Motion of the Public Utilities Commission of the State of California to Submit Comments on the ISO Market Surveillance Committee and PX Market Monitoring Committee Reports on the Ancillary Services Markets Out of Time"

incurred in constructing a plant are sunk costs, even though these costs are usually paid for, through financing, in an annualized fixed payment stream.

The proper compensation to be paid to a must-run generator has been commented on from two perspectives: an economic perspective and a regulatory one. From an economic perspective, a rational generation owner would expect to earn enough revenues to recoup its going forward costs over its relevant decision horizon. This does not mean that a unit must operate profitably in every hour over the lifetime of the plant, but that each decision to incur additional costs is based upon expectations of revenues over the entire period to which those costs apply. Thus, for example, a generation plant that is not running would choose to incur 'start-up' costs as long as its expected profits over the subsequent period of operations are at least as large at these costs. Similarly, a generator would choose to continue to employ personnel and incur cyclical maintenance costs as long as its expected profits over this longer term continue to exceed these periodic fixed costs.

With a durable asset such as a power plant, even profitability over a single year is not a necessity to justify the decision to invest in the plant, as long as the expected discounted operating profits over the lifetime of the plant exceed the costs of the investment. Once incurred, however, sunk costs, such as capital expenditures, would not be considered in the decision to continue operation.[9] Thus, from an economic perspective, the level of compensation required to keep a generator 'in the market' would be its going forward operating costs.

The implementation of RMR contracts in California, however, was approached from a regulatory perspective. As such, parties to the contract negotiations were forced to treat the process as a cost-based rate case. It is our understanding that, under FERC rules, to do otherwise would be applying a form of market-based rates, which requires a satisfactory demonstration of the absence of market power. However, with a *must-run* contract, the presence of market power is definitional. Thus, the RMR contract rates fell under the rubric of cost-based regulation. This in turn led to the inclusion of all 'costs,' including annualized, sunk capital costs, into the rates negotiated by the generators.[10] As Table 1 illustrates, these costs, described in the first row, make up a significant proportion of the reliability and availability payments in RMR contracts.

[9] Opportunity costs, however, would be considered in this decision. Technically, these may include locational 'rents' if the *location* of the generator is also desirable for other uses. Thus, for example, if the location of a must-run generator is also an extremely desirable location for a hotel or hospital, the generator may require extra compensation above its operating costs in order to be prevented from pursuing these other opportunities. However, generation units are usually located on properties that are not especially attractive for most other uses, let alone present a special advantage over other properties for those uses.

[10] Another unfortunate result of this regulatory 'catch-22' was the fact that, the contract terms, although subject to FERC approval, are controlled by the sellers. This leaves the ISO in a relatively disadvantaged negotiating position. The initial result was a confusing diversity of contract terms. One additional goal of the ISO in the current round of RMR contract negotiations is to standardize these terms (but not the rates) across all generators.

Unit's Owner Before Divestiture	**PG&E**	**SCE**	**SDG&E**	**ALL RMR**
Total Capital Cost Recovery	$432,576,823	$75,480,000	$55,592,000	$563,648,823
Total '98 Capital Adds	$39,196,563	$15,857,500	$6,600,000	$61,654,063
Fixed O&M Cost	$218,274,469	$98,260,000	$49,646,000	$366,180,469
Fixed Fuel Cost	$50,387,020	$6,000,000	$18,860,000	$75,247,020
Auxiliary Power Cost	$8,879,316	$6,020,000	$1,277,000	$16,176,316
Total Annual Fixed Costs	**$710,117,628**	**$185,760,000**	**$125,375,000**	**$1,021,252,628**

Table 1: Summary of RMR rates from October 1997 FERC filing

It is important to note that, to the extent that the sunk costs of generation are recovered via RMR contracts, these units are no longer 'stranded' assets. In the terms of the above discussion, a stranded asset is a generation unit whose expected revenues may exceed its going forward costs, but not by enough to recoup its *sunk* costs. Since most of these units were built during a period of rate of return regulation and prudency reviews, it was decided in California that the utilities that had constructed these units would be allowed to recover the remainder of their sunk costs through a competition transition charge (CTC).

In general, it was thought that units that cannot even 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 must be recovered through another mechanism, the RMR contract. Thus the CTC was designed to deal with so called stranded sunk costs, and RMRs were created to deal with units that could not be allowed to retire. For these firms, the inclusion of sunk costs in RMR rates is essentially requiring California consumers to pay for these sunk costs twice—once through the CTC to original owner and the second time through the RMR contract to the new owner. If policy makers determine that the sunk costs of some firms should be guaranteed, this should be done only once through the CTC, and never through the RMR contracts.

This question of compensation for RMR units can be viewed from an alternative perspective to cost-based regulation. The regulatory problem can instead be viewed as determining the allocation of monopoly rents. Recall that location-specific prices are troublesome because of market power concerns. Due to their strategic location within the network, must-run generators would be able to collect above market rents because they face no competition at their specific location. One can therefore view RMRs contracts as a mechanism for paying certain generators *not* to exercise their market power in the daily operation of the market. Ideally, this payment would be implemented in such a way as to not distort the prices in the underlying markets. The most straightforward way to accomplish this is through periodic fixed payments that are not linked to specific market outcomes. In this way, the units with market power still profit from their strategic location, but production and consumption decisions would not be distorted by prices that reflect local market-power. The regulatory question then becomes one of determining a fixed payment that is ‘fair’ to both sides of the transaction.

In this section, we have described several economic principles that can inform the process of determining a fair level of compensation for must-run generation units. We now turn from the question of *what* generators should receive to the question of *how* the payments should be made. By impacting the marginal revenue a generator may earn under an RMR contract, these payment structures relate directly to the question of bidder incentives, and therefore to the indirect impact of the contracts on the energy and ancillary services markets. These different structures are described in the following section.

2.2 Description of RMRs

In this section we briefly describe the two most prominent forms of the current RMR contracts, the ‘A’ contract and the ‘B’ contract, as well as the proposed modifications to the B contract known as ‘son of B’. Roughly speaking, the B contract provides for an up-front payment to cover fixed and sunk costs while the A contract attempts to roll those costs into a variable payment earned only when the unit actually provides RMR services. A fourth contract form, contract ‘C,’ was not very appealing to generators and therefore has not had a significant impact on the RMR process to date. [11] Other important elements of these contracts are described below. The protocols under which these units may be called to generate under an RMR contract are also discussed.

One of the challenges to RMR contract design in California, is the fact that, in many cases, (roughly) equivalent contract structures have been applied to generators with widely varying degrees of must-run status. In other words, the same types of contract options are available to generators for whom must-run status is a relatively rare event, as are available to generators for whom must run status is fairly common. Thus the same formula for either ‘full’ or ‘partial’ sunk (and fixed) cost recovery is applied equally to units expected to be must-run nearly all the time and units almost never expected to be must-run.

2.2.1 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, as was initially envisioned, 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 or not dispatched at a high enough level of energy to

[11] As far as we know, only Hunter’s Point units 1-4 have elected “C” contracts.

cover the local grid reliability needs from that unit, can it be called under the terms of an RMR contract.[12]

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 must-run demand will not be supplied from RMR generation. 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. However, this logic is incorrect, as we illustrate below. Figure 2 draws upon an earlier example 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 2, the true market clearing price becomes P_2. This is the true price of additional system-wide supply. By essentially 'double-counting' some of the must-run demand, current protocols may therefore have been reaching prices that are higher than the level that would actually clear the market.

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, in the above example, the PX price is set above the true price of an additional unit of supply, we would expect this supply to make itself available to the imbalance energy through ancillary service of supplemental energy bids. This would mean that, if demand forecasts were accurate, the real time price would in fact be P_2. However, as described in the August MSC Report, 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 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. We would expect generators to shift their supplies across the two markets by their bidding behavior in the PX and real-time energy markets to maximize the revenue they earn from selling their energy in the two markets. Under conditions of perfect arbitrage, we therefore would expect the average real-time and day-ahead energy prices to converge to the same price. In the above example this can only happen if demand in the PX intentionally under-schedules by an amount equal to the double-counted RMR demand. In short, we suspect that the scheduling of RMR units after the PX market is run is yet another factor that is contributing to the observed under-scheduling, relative to the ISO's day-ahead load

[12] It is our understanding that the ISO has sometimes called generation units under RMR contracts even when the associated must-run energy has been scheduled in the PX. This occurs because energy schedules through the PX are only financial commitments and the ISO's energy requirements for the unit require a firm level of commitment during certain time periods.

forecast, of both supply and demand in the PX.[13] 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.

Recent discussions have produced a proposal for a revised form of 'market first' that would correct this problem. Under this new protocol, the ISO would identify its needs for must-run generation *before* the day-ahead markets are run. This must-run capacity offsets an equivalent amount of demand in the energy market. This demand would therefore be taken out of the day-ahead PX market. Before the market price has been determined, the generators would have to select either their RMR contract rate or the PX price that is subsequently set for that hour. This proposal makes tremendous strides towards solving the problem of incentives for withholding RMR capacity under the current contracts. By giving the generators the choice of receiving the PX price or their RMR contract rate, it also prevents the ISO from using RMR contracts to price-discriminate against generators. In other words, the ISO cannot force generators to take the lower of the market price or their RMR rates. In this way, the spirit of 'market-first' is maintained.

The protocol of market first can, however, also run into difficulty when the 'market' upon which it is based is subject to market power. Recall that the need for RMR contracts arose from the problem of local market power. RMR contracts are intended to compensate units whose costs are above the market-clearing price, but are nevertheless forced to operate. This compensation was considered necessary because the 'price' was being set by cheaper units that could not in fact provide the service in the exact location in which it is needed.

If instead the price is set on a localized basis, the local generating unit can set its own price, and would not need extra compensation. In fact, that unit would most likely be able to earn revenues well above its operating costs due to the lack of local competition. This second case appears closer to what was happening in the ancillary services markets in June and July. Some generators appear to have a 'pivotal' status in providing ancillary services when these services are acquired on a 'zonal' (*i.e.* southern and northern California) basis. Prices for ancillary services frequently hit capped levels during this period. The 'market first' principle has prevented the deployment of RMR units against this form of local market power.

2.2.2 The Current Contract A

The A contract form has no up-front fixed payments. All costs to be recovered have been allocated to a ($/MWH) variable payment. Estimates of annualized fixed and

[13] Other factors contributing to the consistent gap between PX schedules and their associated true real-time volumes include the fact that ancillary services costs are allocated based upon day-ahead schedules rather than actual load, and the ISO's price cap on real-time energy prices.

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.[14] 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. It our understanding that in the future, this estimate of energy output will be based upon a rolling 5-year average of historic output.

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[15] 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. Generators not operating at the time of the RMR call are 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 a certain 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 overall percentage of forecast energy provided by RMR units has been around 35% in the first four months of operation, although that percentage has varied significantly from month to month. As we describe below, the percentage of must-run energy provided through RMR contracts, rather than the market, is strongly linked to the PX price.[16] However, some individual units have been providing RMR energy at a rate that is on pace to their forecast annual energy levels. These have tended to be the units with relatively low forecast energy output, and therefore relatively high reliability payments. The percentage of RMR unit fixed and sunk *costs* that are paid under RMR contracts is therefore higher than the system-wide percentage of *energy* provided from RMR units under RMR calls.

We strongly suspect that units with low output forecast have considerably more variability to their annual output than units with higher output forecasts. For example, it is far more likely that a unit forecast to run only 50 hours a year would triple its forecast than would a unit predicted to run 2500 hours in a year.

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[14] The description of this conversion in the August 17th MSC report was in error, as several stakeholders have pointed out in their comments. The August report stated that annualized costs were divided by a forecast of *RMR* energy, instead of a forecast of *total* energy.

[15] These costs can include environmental emissions, fuel, and variable O&M costs.

[16] The higher the PX price, the more likely must-run units are to generate through the market, and vice-versa.

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, 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. If enough generators are influenced by these opportunities, market prices themselves will be driven upwards from what they might have been without RMR contracts. We discuss the evidence of such behavior in section 3 below.

2.2.3 Current Contract B

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 the historic availability levels of each unit. 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.[17] 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.

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 market earnings. 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 is minimized by the rebate requirement. The unit gives up less variable profits per unit from not participating in the market. Other things being equal, ancillary service markets would appear more attractive than energy markets to a B contract generator since the former requires no rebate of market earnings.

While most of the RMR capacity in California, including all of the gas-fired capacity, have given notice of converting from A to B contracts for the remainder of 1998, many of these 'switches' did not take effect until October. The only units under B

[17] The total amount paid back under this rebate is capped at the level of the RMR fixed payment.

contracts during the time period analyzed below belong to the investor-owned utilities and one of the new generation owners.

It is our understanding that when the new contracts take effect, firms will once again be able to choose between A or B contracts, assuming these two contract forms still exist. Market conditions will again have changed somewhat from what they are currently. One should therefore not assume that, because a generator prefers to be under a B contract for the remainder of 1998, it will automatically prefer to be under a B contract in 1999. In general, an RMR generator would prefer to be under an A contract, with no revenue rebate requirements, when market prices are high as they were in the summer. Similarly, most generators would prefer to be under B contracts, with their monthly fixed payments, when market prices are low and there is little profit left over for rebates.[18]

2.2.4 Contract C

As was mentioned above, the C contract received little interest from RMR generators during the first year of the market's operation. This is because, from the perspective of generator whose unit is economic at the PX price a sufficient number of hours, the B contract is preferable to the C contract. The C contracts, like the current B contracts, pay 100% of a unit's fixed and sunk costs. Unlike the B contracts, generation units with C contracts are not allowed to earn any market revenues from sales in the PX or other energy markets. Thus, while a generator could make at least some additional profit from market sales under contract B, there are no such opportunities with contract C. It is therefore not surprising that few units converted to a C contract.

If the contract forms described here are continued in the next contract cycle, the ISO anticipates that some generators may select contract C over the new 'son of B' contract, described below. This is because the son-of-B contracts allow for a maximum of 90% of a unit's sunk and fixed costs to be recovered through monthly payments. Thus a unit that could truly never operate profitably in an energy market, even during peak hours, would prefer contract C. Contract C would allow such a unit to recover 10% more of its fixed and sunk costs than would contract B, with no penalty since the opportunity to earn market profits under a B contract would hold no value to such a very uneconomic unit.

2.2.5 The Proposed B (Son of B) Contracts as of December 1998

The son-of-B contracts expand upon the up-front payment and market revenue rebate concept of the original B contract. Instead of a single option of payments based upon full recovery of annualized fixed and sunk cost combined with a rebate of 90% of the sales margin, the son of B offers a menu of trade-offs between up-front payments and sales margin rebates. These trade-offs range from the original 90% fixed-cost recovery and 10% retention of sales margin (90-10) to 20% fixed cost recovery and retention of

[18]It our understanding from the ISO that in the next contract cycle, it is proposed that generation units will be committed to one form of contract for a full year, assuming these two contract forms continue.

92% (20-92) of sales revenues. In other words, a generator could opt to receive only 20% of its fixed cost in a guaranteed monthly payment and thereby only be obligated to refund 8% of its sales margin back to the ISO whenever that generator participates in a market.

The payment schedule specified by the son-of-B percentages will apply for RMR calls up to the percentage of hours specified for fixed cost recovery. Thus, for example, a unit that selects 20% fixed cost recovery will earn a payment based upon its variable cost for the first 20% of available hours in which it is called for RMR services. If the unit is called upon to provide RMR services for more than this percentage of hours, (*i.e.* the share covered by the availability payment) a pro-rata share of fixed costs (up to 100%) will be added to the variable RMR payment received by that unit. The son-of-B contracts therefore effectively revert to an A style contract when their hours of RMR operation exceed the number of hours specified in their availability payment.

Unlike the original B contracts, market revenues are not immediately rebated under son-of-B contracts. A generation unit would keep all of its market revenues up to the point that 100% of its annualized sunk and fixed costs are recovered from either (deemed) market profits, availability payments, or reliability payments. Once its fixed and sunk costs have been covered from some combination of these sources, a unit with a son-of-B contract would begin to rebate the percentage of market revenues specified by the contract.

2.2.6 The Proposed New Contract A and C as of December 1998

If the A and C contracts are continued, they will remain largely unchanged from their original form, with a few notable exceptions. First, as mentioned above, the new A contracts will cap annual reliability payments at 100% of the unit's annualized fixed and sunk costs. Second, one proposal calls for all RMR units, including those under the new A and C contracts, to be called upon *before* the day-ahead markets are run. All C units would be required to submit standing bids into the PX, and all revenues in excess of variable costs of operation would credit against the 100% fixed cost payment.

2.2.7 RMR contracts and Ancillary Services

The discussion so far has emphasized RMR units and the need for *energy* in specific locations. RMR contracts have also become an insurance policy against bidding shortfalls in ancillary markets. The application of RMR contracts to ancillary services involves a new set of issues relative to those involving RMR units and the energy markets. Generally, RMR units called to provide ancillary services are called not due to a specific locational need but due to a shortfall of suppliers bidding into those markets.

One important difference between the application of RMR contracts to energy and ancillary services lies in the degree to which the generators themselves can increase the likelihood of an RMR call. Most must-run energy requirements are based upon demand levels, system conditions, and reliability protocols that require the system to withstand various 'contingencies' such as an outage of a large generator or transmission line. These factors are, for the most part, beyond the control of an individual generation firm.[19] However, ancillary service RMR calls are generated, in part, by bid shortfalls, rather than reliability requirements. Generators can, through their bidding behavior, therefore affect the ISO's RMR requirements for ancillary services.

Determining the revenues earned by units called under RMR to provide ancillary services needs are also more complicated than for units called upon due to local energy requirements. Under the original contracts, some units could earn RMR revenues for providing ancillary services, while others could not. In fact, it is our understanding that some RMR units have earned the *market clearing* price for an ancillary service, when they are called upon under an RMR contract to provide that service. This means that these units could earn up to $250/MW for the provision of reserves under RMR contracts. These ancillary service discrepancies between contracts will be removed under the new contracts. Under the new contracts, RMR rates for ancillary services will be based upon a formula that divides the annual fixed and sunk costs of each unit by the annual capacity available to provide each service. [20]

It is important to note that, for the most part, RMR payments for the provision of ancillary services will be relatively modest under the new contracts. This might indicate that a strategy of withholding capacity from the ancillary services market in the hope of receiving RMR payments will not be a profitable one. However, other factors may affect that conclusion. Other forms of compensation beyond the ancillary service payments, which are discussed in more detail below, may also be earned by a unit called under RMR to provide certain ancillary services. RMR units that comprise part of a firm's generation portfolio can also impact that firm's bidding behavior, even if, from the standpoint of that single unit, it may not appear profitable to do so.

2.2.8 Other compensation

As mentioned above, generators can also earn compensation for costs incurred preparing their unit to provide either energy or an ancillary service. For example, a unit that is called upon to provide spinning reserve needs to generate at a minimum operating point from which its output can be rapidly increased. Such a unit would be potentially entitled to compensation for starting-up the unit, ramping its output to its minimum operating point, and the operating cost of maintaining its output at that level. Any energy that is generated in the process of preparing or maintaining a unit's ability to provide an ancillary service is compensated according to that unit's RMR energy rate. A unit with an A contract that is called upon under that contract to operate at a minimum level in order to provide spinning reserve therefore receives its variable cost and its reliability rate for the energy generated in the process of getting to and maintaining that minimum operating level.

[19] Some must-run requirements do take the follow rules such as 'at least one of three units in a specific location must be operating.' To the extent that a single firm controls all three of these units, it can also influence the need for an RMR energy call on one of them.

[20] Availability estimates will be based upon the historical average performance of each unit.

Units called upon to start-up under an RMR contract are also guaranteed some level of RMR compensation for the duration of that unit's minimum 'up-time.'[21] A generation unit could benefit from an RMR call by having its costs during start-up and no-load paid for under the contract and then, having had these 'preparation costs' paid, subsequently sell power through the market. These benefits are not insignificant, and represent another set of opportunity costs to participating in a day-ahead market. A unit that bids successfully into an energy market, and thereby has to incur the costs of starting up and 'ramping' the unit in preparation to meet its market obligation, has forgone the 'opportunity' to have those costs paid for under an RMR contract. To see this, consider a traveling salesman that would ordinarily have to pay his own round-trip travel and lodging expenses if he visits a given region. Now consider that this salesman knows that, if he doesn't travel to the region on his own, there is a reasonable chance that his client will summon him to that location and in the process pay his travel expenses for him. A rational salesman would adjust his travel plans accordingly.

We feel that the best way to mitigate the incentive effects of start-up payments is to incorporate an estimate of RMR start-up costs into a periodic fixed payment that is not directly linked to the number of starts incurred during that period. With this solution generators would not have their operating decisions influenced by the prospect of additional start-up compensation.

3 Impact of RMR Contacts on the Behavior of Market Participants

In this section we describe how RMR contracts influence the bidding incentives for generators and consumers in the day-ahead energy market and ancillary services markets. These influences create additional *direct* costs to the ISO in additional RMR payments, and *indirect* costs to all consumers from increased market-clearing prices for energy and ancillary services. We then discuss evidence that indicates that these incentives are indeed effecting the behavior of generators with RMR contracts.

The impact of RMRs on bidding behavior is but one element, albeit a significant one, impacting the overall competitiveness of these markets. These elements are not fully separable, and the interaction between them can enhance the impact of an individual element. Thus a firm without any RMR generation may still find it profitable to withhold some capacity and bid its remaining capacity at a higher price, just as a single RMR generator may find it profitable to bid its expected RMR earnings. We would expect that the bidding behavior of a firm with relatively more market power is likely to be more influenced by the presence of RMR contracts than one with relatively less market power. However, it is important to remember that factors that allow some firm to raise prices, benefit all suppliers, even those behaving as price-taking firms. In this way, market rules and structures that inhibit aggressive competition can have a 'feedback' effect with broad implications for the whole market.

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[21] In order to minimize the thermal strain on generation units, most have limits on the minimum number of hours that a unit should operate once it has been started, as well as the minimum number of hours it must remain shut down before starting again.

Because of this interaction, it is extremely difficult to determine how much impact each element may be having on the market competitiveness. In the following sections, we first present data that indicate that the current RMR contracts do influence bidding in these markets. Quantifying the impact of RMRs, and the incentives that they provide, on the market prices for energy and ancillary services, however, is a more difficult problem. One can attempt to measure the overall impact of market power on the energy market by comparing observed market prices with estimates of the prices that would obtain if every firm acted as a price-taker.[22] Because of the interaction of RMR contracts and horizontal market power, it is more difficult to isolate the contributions that RMR contracts have made to the observed level of overall market power. If one focuses only on the RMR capacity, this will miss the impact of RMRs on the strategic behavior of other units and firms. We therefore have taken bidding data obtained from the PX and estimated the impact of RMR calls on the bidding behavior of several firms. Although we have continued to refine our analysis since December of 1998, we must stress that these are at best very broad estimates. However, we believe these results do provide us with an estimate of the order of magnitude of the problem. We feel that this magnitude, on the order of hundreds of millions of dollars over four months, indeed warrants the attention of stakeholders.

Much of the following discussion focuses on the interaction of energy markets and RMR contracts. Less emphasis is placed upon the interaction of RMRs with the ancillary services markets. This is largely due to the fact that it is much easier to describe and to analyze the trade-offs for generation units between providing RMR energy and selling energy through the market. This is not to say that RMR contracts have no effect on the behavior of firms in ancillary services markets, only that those impacts are somewhat more difficult to isolate from the other factors impacting ancillary services markets.

3.1 Impact of RMR on bidder behavior and market prices

RMR contracts can effect the participation of firms in the energy and ancillary services markets in two ways. This first is to give firms incentives to bid less aggressively,[23] thereby allowing them to set higher prices in the PX and ISO markets for their RMR (and non-RMR) generation plants. The second effect is to cause firms to withhold capacity from the PX and ISO markets altogether. As with higher bids, withholding capacity can increase the likelihood that a generator's RMR generation units will be called to provide energy or ancillary services under their RMR contracts, and can also lead to higher prices for the capacity that is not withheld. In this sense, the 'withholding' of capacity is really just an extreme case of strategic bidding. For example,

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[22] Borenstein, Bushnell, and Wolak (1999), "Diagnosing Market Power in California's Electricity Market," mimeo, University of California Energy Institute, perform such an analysis on the California market, as does Wolfram (1999), "Measuring Duopoly Power in the British Electricity Spot Market," *American Economic Review*, forthcoming, for the U.K. market.

[23] In this paper, we use the convention that aggressive behavior is more competitive and less aggressive is less competitive.

bidding capacity into a market at a price that has almost no chance of winning, or even at a price above ISO price-cap levels, is virtually equivalent to withholding the capacity.

In either event, we are not claiming that firms should not be taking the RMR contracts they have into account when they formulate their bidding strategies. Indeed, these firms have an obligation to their shareholders to attempt to maximize profits, subject to the rules of the market. Our goal here is to demonstrate how some of those market rules have distorted the incentives of firms to an extent that, when they do maximize their profits, some very inefficient prices and outcomes can result.

The economic rationale behind the incentive effects of RMR contracts follows from the assumption that a generation owner with RMR units will attempt to maximize its expected daily profits from all of its capacity (RMR and non-RMR) in the energy and ISO markets. The existence of RMR capacity provides these generation owners with a 'backstop' level of expected profits during each hour of the day. This backstop profit level will depend, among other things, upon the magnitude and geographic distribution of demand in the electricity grid. Each firm knows that, if its RMR units are not taken in the day-ahead energy or ancillary services markets, there is still a chance they might be called under the RMR contract in one of these markets and compensated accordingly.

The existence of an RMR contract therefore creates, for each generator, a clear opportunity cost of scheduling power through either the PX or another scheduling coordinator. This opportunity cost consists of the unit's expectation of RMR revenues less its costs of providing services under RMR. Under an A contract, a unit with a high reliability payment, or a high probability of being called under RMR, will have a relatively higher opportunity cost of participating in the energy market. In the PX, we would expect a rational generator to incorporate its RMR opportunity costs into its bids. In other words, a single generator with relatively high expected RMR revenues for a given hour would not want to be chosen to generate from the PX at a price that is lower than those expected RMR revenues, and would adjust its bids into the PX accordingly.

Consider the following example. Generation unit Alpha has an A style RMR contract that pays it $100/MWH. Before the day-ahead energy markets are run, Alpha calculates, after observing load forecasts and system conditions, that there is a 75% chance that its generation will be considered must-run in hours 10-20 of the following day. If this unit sells power through a day-ahead market, it will lose the 'opportunity' to sell it under RMR instead. The opportunity cost of selling in a day-ahead market in these hours is, in expectation, $75/MWH. Other things being equal, this generator would not want to sell into a day-ahead market at a price below its opportunity cost.

The potential impact of RMR contracts on the bidding behavior of firms that own a 'portfolio' of multiple generating units is even greater. RMR contracts affect portfolio bidder incentives by changing the expected payoff of 'losing' bids. Normally the formulation of a bid to supply a product involves balancing the trade-off between earning a higher price with the risk of not being selected and therefore not earning anything. A higher price bid might, if selected, earn more but also stands a smaller chance of being selected. The introduction of an 'A' style RMR contract into this equation means that a unit whose bid is not successful may, if called under RMR, still earn revenues that exceed its operating costs. The downside risk of bidding higher prices into the PX (or equivalently, asking for a higher price in a bilateral negotiation), is thereby lessened.

3.2 Capacity Withholding and Market Participation

In the previous section we argued that RMR contracts, by creating opportunity costs of market participation, provide incentives for generators to bid less aggressively in the day-ahead energy and ancillary services markets. In this section we focus on one aspect of this effect--capacity withholding. We give a more precise definition of capacity withholding and describe the economic rationale for this behavior. Empirical evidence of capacity withholding from both of these markets is then presented. In the following sections, we explore the relationship between RMR contracts and bidding behavior, including withholding.

The focus of our analysis is on capacity withholding from the day-ahead energy and ancillary services markets. The ISO's total RMR requirements, net RMR energy and total ancillary services schedules are determined after the day-ahead energy and ancillary services markets have been cleared. We therefore assume that the ownership of RMR contracts should not significantly impact bidding in the hour-ahead energy and ancillary services markets and the real-time energy market. To the extent that conditions in the hour-ahead energy and ancillary services market impact actual RMR energy usage, these contracts may affect bidding in the hour-ahead and real-time markets. However, the potential increase in profits to a generator's RMR units from withholding capacity from the hour-ahead and real-time markets seems small. Consequently, we focus our attention on the day-ahead energy and ancillary services markets, while recognizing that we may be missing some of the adverse effects withholding on the operation of hour-ahead PX and ISO markets.

Defining capacity withholding in the California market is complicated by several factors. First, because generators bid portfolio supply curves into the PX and are free to satisfy the quantity won in this market using their plants how ever they see fit, it is impossible to say whether any specific generating facility was or was not bid into the PX market. If the PX rules required each segment of a generator's bid curve to be associated with a specific generating unit, measuring the extent of capacity withholding from the day-ahead energy market would be straightforward. In any event, in this section we focus on capacity that is not scheduled to provide energy in any day-ahead market, and rely upon day-ahead energy schedules in the ISO.

A second complication in measuring capacity withholding stems from the price-cap on the ISO's real-time energy. PX market participants who are net demanders of electricity recognize the existence of this cap and submit demand-side bids into the PX that effectively curtail their demand from the PX at prices above the ISO's cap on the real-time energy market. Consequently, generators know that the portions of their portfolio bid curves into the PX above the real-time energy cap will be selected with close to zero probability.

A third complication is that day-ahead energy can also be traded outside of the PX. However, these trades must also be scheduled through the ISO on a day-ahead basis. A measure of capacity withholding must account for all of the possible ways that California generating capacity can be used to supply electrical energy.

A fourth complication is the interaction between the energy and ancillary services markets. A firm that does not apply its capacity to the provision of energy may still 'utilize' its capacity by bidding it into an ancillary service market. Fortunately, capacity withholding from each of the day-ahead ancillary services market is relatively straightforward to measure. Price and quantity bids in each market are associated with a specific generating facility and all bids, even those plants not selected in the market are observed. Generation units that do not participate in any day-ahead markets, but subsequently bid into the hour ahead and 'imbalance' energy markets do not enter into this calculation, however. Consequently, some capacity could be withheld from the day-ahead energy and ancillary services markets in anticipation of bidding into the hour-ahead or real-time energy market.

One last complication is defining the exact capacity of a generation unit. The output capacity of all generation units varies somewhat over time due to such factors as the ambient air temperature. Planned and unplanned outages will also reduce the amount of capacity that is available. For all these reasons, the withholding figures that we compute will therefore somewhat overstate the amount of capacity that is withheld. We therefore focus more on the trends in withholding, and the differences that we observe between the amount of withholding by new generation owners (NGOs) and that of the incumbent investor owned utilities (IOUs), than on the exact withholding figure.

We define the amount of capacity withheld as the amount of capacity that is not scheduled in the day-ahead energy or bid into any of the ISO's day-ahead ancillary services markets. This is calculated by taking the ISO's figure for the capacity of a generating facility and subtracting the sum of day-ahead energy scheduled from that unit and total amount of from the unit that is bid into the ancillary services market at any price.

Summing this quantity over all units owned by a generating company yields the total capacity withheld from each ancillary services market. Recall that the ancillary services markets are cleared sequentially, regulation first, then spin, non-spin and finally replacement. We do not net out the amounts won in the higher quality ancillary services markets in measuring the total amount bid into a specific ancillary services market, because this may obscure the impact on the capacity withheld from each market of the extremely frequent event that a generator is willing to sell less of an inferior ancillary services product at a higher price than it is willing to sell a higher quantity of a superior ancillary service product.

Figures 3 through 10 plot the hourly fraction of total capacity withheld from the day-ahead energy and ancillary services markets for each ancillary service for the IOUs and NGOs for each month during our sample period. For each hour these figures compute the fraction of total capacity that has not been scheduled in the day-ahead energy market or bid at any price into that the ancillary services market. We present the results in this way to account for the fact that there are ownership changes in generating units during several of our months, and we wanted to be able to compare the degree of capacity withholding across months and weeks. This required normalizing the amount of capacity withheld in any hour by the total amount of available capacity in that hour.

The most stark result immediately apparent from these graphs is the tremendous amount of capacity withholding by the NGOs during all months of the sample. For example, during the entire month of June except for a few hours on June 30, the NGOs withheld more than 90% of their 'available' capacity from the 3 highest quality ancillary services markets. For replacement reserve, they withheld more than 80% of their available capacity in all hours of the month except a few hours on June 30 when they still withheld more than 70% of total capacity from the market. During June the IOUs also withheld a significant amount of capacity from the day-ahead markets, with the hourly level for all four ancillary services markets between 60% and 40%, still considerable amounts of withholding

The other three months continue to show significant amounts of capacity withholding, but the average hourly capacity withholding fraction falls for both the NGOs and the IOUs and the volatility across hours increases. For example, in August the hourly withholding fraction for the IOUs ranges from 50% to 10% for all four markets. Even in August, a period of high demand and high PX prices, the NGOs withheld between 90% and 40% of their capacity from the 3 highest quality ancillary services markets. Even for the replacement reserve market the lowest hourly fraction of capacity withholding was still 30%, and that was only for a few hours during the month. As evidence that the high levels of capacity withholding in June were not a one time event, note that the September graphs of the capacity withholding fractions shows an upward trend to levels that are fairly similar, as the demand for electricity during that month continued to fall. As prices in the PX trended downward and became less volatile, withholding once again increased.

Note that there were not actual shortages of capacity during this time: total ISO load continued to be supplied by generators producing in real-time. A portion of this available capacity therefore was not offered to any advance energy or ancillary service market. These figures are drawn from ISO day-ahead schedules, and therefore do not reflect the full details of bidding strategies in the PX, or the activities in the supplemental energy market. The magnitudes and trends of these aggregated figures are still, however, very informative about how much of the capacity that was physically available to bid into day-ahead ancillary services markets did not choose to do so. In a conference call with several of the generation companies, some of the generators stated that the complexities of the ancillary service bidding protocols, and limitations on the time available to formulate bids had contributed to their lack of participation in these markets. Some firms stated that during this period they were offering energy to the ISO imbalance market only through adjustment bids, rather than through the ancillary services markets. The results of this phenomenon, and some of the other factors contributing to it, have been well documented in the August reports of the MSC and PX MMC.

3.2.1 Capacity Withholding in the Power Exchange

Using data obtained from the PX, we have been able to do some analysis of the question of capacity withholding in the PX. This analysis indicates that there has been some degree of withholding from the PX as well, particularly in periods when the Day-ahead ISO Load Forecast is very high. Our reasons for this belief can be seen from Figures 11-18. Figure 11 plots the hourly day-ahead ISO load forecast for each hour for each month in our sample. Included on these same graphs are the aggregate hourly PX bid supply at a price of $100/MWH and this same magnitude at a price of $250/MWH. For the month of June the amount bid into the PX at a price of $100/MWH and $250/MWH was above the day-ahead ISO load forecast for all but the highest load hours. However, during the months of July, August and September (Figures 12-14) during almost all peak and shoulder hours during the day, the amount bid into the PX at both $100/MWH and $250/MWH was significantly below the day-ahead ISO load forecast, often by several thousand MWH. During the high-priced periods in August and September the extent to which the amount supplied into the PX at these two prices was below the day-ahead ISO forecast was higher than 10,000 MWh. For all hours during the four months, the total amount bid in at a price of $2500/MWh is not much larger than the amount bid in at a price of $250/MWh. These graphs indicate that one reason for high prices in the PX is that suppliers do not bid into the PX, at any price, capacity sufficient to cover the vast majority of the day-ahead ISO load. This is the sense in which capacity is withheld from the PX market. In the peak hours of most days during the months of July and August, suppliers are unwilling to bid a quantity within 5,000 MWH of the day-ahead ISO forecast even at the PX price cap of $2500/MWh.

We should note that one of the reasons suppliers may not bid more than the forecast of the ISO load into the PX is because some the generators that sell into the PX can also take advantage of more lucrative opportunities to sell electricity outside of the PX. Another reason suppliers may bid significantly below the ISO load forecast into the PX at $250/MWH is because of the actions of demand bidders to reduce the price they pay for power purchased from the PX by bidding lower aggregate demands at higher prices. Suppliers therefore offer less into the PX in order to receive a higher price for their energy in the hour-ahead or real-time energy market. To explore this issue, in Figures 15 through 18 we compute the demand-side analogue to the plots in Figures 11-14. We plot the hourly aggregate demand bid at $25/MWh and $50/MWh, along with the hourly day-ahead ISO load forecast. During the month of June, the aggregate demand bid in at $25/MWh and $50/MWh is below the day-ahead ISO forecast. This reflects, in part, the fact that the average market-clearing price during this month is significantly lower than $25/MWh. However, even at a price of $0/MWh the PX demand is significantly less than the ISO day-ahead load forecast during the month of June.

During the months of July, August and September, the PX aggregate demand at \$50/MWh and \$25/MWh more closely tracks the day-ahead ISO load forecast. Furthermore, the aggregate PX demand at these prices is significantly closer to the day-ahead ISO load forecast than is the aggregate supply bid at a price of \$250/MWh, or even \$2500/MWh. This is particularly true during the first few days of September. During the peak hours of these days, the amount that the PX demand at \$25/MWh or \$50/MWh is below the ISO load forecast is significantly smaller than the amount that the aggregate PX supply at \$250/MWh is below the day-ahead ISO load forecast. Similar statements can be made about the very high demand hours in August and late July.

The graphs in Figures 11 through 18 imply that for certain high demand periods in July to August, the PX aggregate supply bid curve intersects the PX aggregate demand curve at a quantity of MWh very close to the PX aggregate supply at a price of \$2500/MWH, i.e., on a very steep portion of the PX aggregate supply curve. To investigate the frequency of this event we computed the following ratio for each hour during our sample

$$\frac{\text{(PX Supply at \$2500/MWH – PX Market Clearing Quantity)}}{\text{(PX Market Clearing Quantity)}}$$

This ratio measures how 'close' the market clearing quantity is to the vertical portion of the supply curve. During these hours a very small increase in demand, or decrease in supply can lead to a very large increase in price. We found that during the month of June, in no hour was this ratio less than 0.05. However, this ratio was less than 0.05 during 3% of the hours in July, and 4.4% of the hours in August. In September, this ratio was less than 0.05 in 2.5% of the hours.

3.3 Impact of RMR contracts on bidding behavior and capacity withholding

In the previous section, we described the level of capacity that is not participating in either day-ahead energy or ancillary services markets. In this section we present some analysis aimed at determining the influence of RMR contracts on this phenomenon. Recall from the previous discussion of the incentive effects of RMR contracts, that these contracts provide a 'backstop' expected revenue to generators that do not participate (or bid too high) in the energy and ancillary service markets.[24] This backstop revenue creates an opportunity cost of market participation. There are several ways in which we can begin to link the 'opportunity' cost of participating in an energy or ancillary services 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

[24] Recall once again that capacity withholding can be though of as simply an extreme case of bidding high. As noted earlier, bidding into the PX at above the real-time energy market price cap of \$250/MWh is effectively withholding capacity from the PX because of the bidding behavior of loads into the PX in light of this \$250/MWh price cap in the real-time energy market.

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 units are indeed 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 that it considers 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 generators whom the ISO considers to be must-run that do not schedule any energy. 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 through the day-ahead energy markets, 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.

Figures 19 through 22 show the PX price and the average RMR rate earned by generators declared to be must-run. That is to say, the average RMR rate of the ‘gross’ RMR generation. 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.

Figures 23 through 26 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 to the ‘gross’ need for energy in months such as June and late September when the PX price is considerably lower than the average 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 indicates that generators are indeed, as we would expect, utilizing their RMR contracts, with the associated backstop revenues, in a profit-maximizing way.

3.3.1 Impact of RMR contracts on Bidding in the PX

As we have noted several times throughout this report, the existence of RMR contracts that are called after the PX market clears creates an opportunity cost of selling power into a day-ahead market. If these RMR contracts have per MWh payment rates that incorporate a payment for fixed and sunk costs, this opportunity cost is raised because the foregone expected profits from not participating in the PX with this amount of capacity is higher, and therefore PX bidding behavior is distorted in favor of higher bids than would exist in the absence of this higher opportunity cost.

To illustrate this intuition, consider the following example. Suppose that a unit owner with a marginal cost of $10/MWh has an RMR contract that pays its marginal cost for each unit of RMR energy. All other costs of providing this service, including start-up costs, are paid up-front to the generator. In this case, if the generator does not win in the PX market and is called to provide energy under its RMR contract, it stands to earn zero variable profit for energy provided under this RMR contract. A generator with this RMR contract has very high-powered incentives to bid into the market at or slightly above its marginal cost, because the expected variable profits from bidding too high and being left out of the market is zero.

In contrast, consider this same unit owner with an RMR contract that pays variable costs plus and a contribution to fixed and sunk costs, so that the payment per MWH is $60/MWh. Using the above logic, we can see that under the same conditions on the probability of an RMR call, this unit owner faces a dramatically different opportunity cost of bidding into the PX. If he is not dispatched through the PX and called under his RMR contract he earns a per unit profit of $50/MWh. We would therefore expect a generator with this sort of contract to bid significantly higher prices into the PX, especially during the periods in which the likelihood of an RMR call is particularly high, because of its higher opportunity cost. Unlike an RMR contract that pays only marginal cost, this contract gives the generator an incentive to bid significantly higher than his marginal cost. In periods when are RMR calls are very likely, the opportunity cost of not bidding into the PX increases. A generator with such a contract should bid even higher during these periods. Given that A contracts provide generators with an incentive to bid higher prices, we turn now to the question of how great an impact this incentive effect has had on the California markets. We focus on the PX, both because it is the largest single market effected by these incentives and because the opportunity costs presented by RMRs is more straightforward to assess.

As discussed earlier, it is difficult to distinguish between capacity withheld to raise PX prices and capacity that is being held out of the PX to bid into the ancillary services, hour ahead energy or real-time energy markets. Consequently, in estimating the impact of RMR incentives on PX prices, we assume that there is *no* strategic withholding of capacity in any hour due to RMR contracts. In other words, we assume that in the absence of the perverse incentives for bidding behavior in the PX caused by the current RMR contract the same total quantity of electricity will be bid into the PX each hour. We therefore focus our analysis only on the influence that RMR contracts have on the prices bid into the PX markets, holding constant the total capacity (at any price) bid into the PX market by each participant. The consequence of this assumption will therefore tend underestimate the impact of RMR contracts on the day-ahead markets. This is because other evidence, discussed above, indicates that there has been some withholding of capacity from the PX day-ahead market.

3.3.2 Impact of RMR contracts on Demand Bidding into the PX

An important element of the impact of RMR contracts on the day-ahead energy markets is the impact of those contracts on the *demand* bids in those markets. 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. There is strong evidence that market participants have indeed attempted to arbitrage the PX and ISO imbalance energy prices. This evidence also indicates that this arbitrage has been far from perfect, although it has improved over time.[25] The interaction of market arbitrage and RMR contract incentives appears to be very complex. In an extreme 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 equal to its expected RMR earnings 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. In this way the fact that market rules cause the PX to transact too much supply would in theory be offset by the lower level of demand offered by consumers.

Unfortunately, several factors appear to inhibit the ability of demand-side response to completely counteract the incentive effects of RMR contracts. Demand response has a very limited ability to counteract the incentives provided by B-style contracts. The requirement that units under B contracts rebate a large share of their market earnings back to the ISO reduces the incentives of those units to participate in the market *all the time*, not just when those units are likely to be must-run. These units would be as uninterested in offering supply in through the ISO as they were in offering it through the PX. Shifting demand from the PX to the ISO would therefore have little impact on overall price.

Another complicating factor is that the RMR quantity called under contract, which in some cases would be the amount that should be under purchased by consumers,

[25] See Borenstein, Bushnell, and Wolak,1999, 'Diagnosing Market Power in the California Electricity Market,' mimeo, University of California Energy Institute, and also Bohn, Klevorick, and Stalon,1999, 'Second Report on Market Issues in the California Power Exchange Energy Markets.' Both analyses show that average PX and ISO prices have been converging over time, although they were significantly different during most of the summer of 1998, which is the period studied below.

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. However, 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.

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. It is not at all clear that the gains from such a strategy would offset the costs. There is a substantial body of economic work which indicates that, in an oligopoly environment, the existence of a sequence of forward markets linked to a spot market helps to stimulate competition amongst suppliers.[26] This appears to be especially true in the case of electricity markets, which are characterized by a lack of storage and inelastic demand.[27] In the case of a single, real-time spot market, suppliers can make a much more credible threat to not sell electricity than can distribution companies make to not buy electricity. Final customers have very high expectations that all of the electricity they demand will be delivered in real-time. It therefore seems likely prices in California would be higher in the absence of day-ahead and other forward markets than they have been in the presence of these markets. Factors that tend to make it more expensive for consumers to trade in forward markets, relative to the spot market, can therefore reduce the effectiveness of these markets in promoting competition. The incentive effects of RMR contracts, by raising the offer prices of suppliers in the day-ahead markets, are such a factor.

One last issue to consider when discussing the impact of RMR contracts on demand bids is the incentives of the firms submitting those bids. 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

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[26] See, for example, Allez, B. and Vila, J.L., (1993), 'Cournot Competition, Forward Markets, and Efficiency', *Journal of Economic Theory*, 59, pp. 1-17.

[27] For applications of these results to the study of electricity markets, see Powell, A., 1993, 'Trading Forward in an Imperfect Market: The Case of Electricity in Britain', *The Economic Journal*, 103, pp. 444-453,Green, R.1999, 'The Electricity Contract Market in England and Wales,' *Journal of Industrial Economics*, 47(1), and Newbery, D. 1998, Competition, Contracts, and Entry in the Electricity Spot Market, *Rand Journal of Economics*, 29(4):726-750.

day-ahead market must actually have some demand to underbid.[28] The ability to respond to RMR effects is therefore largely limited to the three large distribution utilities. It has been frequently observed that the incentives of these firms are difficult to interpret. While all three firms were subject to a rate-freeze during the summer of 1998, the impact of energy 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. In aggregate, the incumbent IOUs were also significant suppliers of energy into the PX market during the summer of 1998.[29] 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 below. These results indicate that, the *aggregate* response of IOUs to RMR contract levels tends to increase, rather than decrease PX prices.

It is important to consider that some of the changes that are underway in the California market may in the future make it even more difficult for a demand response to offset RMR incentive effects. It appears that the transition period, and therefore the rate freeze, for at least two of the three IOUs will likely expire before 2001. If these firms are allowed to pass-through their energy costs to end-use consumers, these firms will be, on the distribution side, largely indifferent to the level of energy prices. The ISO is also proposing to allocate the costs of replacement reserves according to the extent to which day-ahead schedules are below actual loads. Any firm that attempts to offset RMR effects by shifting load to the ISO's imbalance energy market would therefore have to pay an additional cost equal to the price of replacement reserve in that hour. Although we believe that prices for replacement reserve should be negligible most of the time, during high price periods, particularly when the imbalance energy price cap is binding, replacement reserve prices could be substantial. These are also the periods in which the influence of RMR contracts, and the ability of firms to exercise market power is at its greatest.

3.3.3 Price Calculations

Our analysis therefore focuses on the increased cost of purchasing energy due to the influence of both types of RMR contracts on the bids of generators. The analysis proceeds in the following manner. First, we collected historical PX price (PXP) and market-clearing quantity (PXQ) for each hour from June 1 to September 30. This is necessary to compute the historical cost of purchasing power from the PX during each hour in our sample period. We then obtained all historical supply and demand hourly portfolio bid curves for each market participant for the period June 1 to September 30.

[28] A firm could also over-offer supply, but must have the actual generation resources (or transmission interface capacity) with which to do so.

[29] Bohn, Klevorick, and Stalon report that, although the IOUs made, in aggregate about $4 billion worth of purchases from the power exchange during 1998, their *net* purchases (after sales) were only around $300 million during that time.

The next step of the analysis required developing algorithms to construct the PX aggregate supply and demand bid curves from all of individual portfolio bid curves submitted during each hour and to compute the market-clearing price and quantity for any aggregate PX supply and demand bid curves. As a check of these procedures, we replicated actual the hourly PX prices and quantities for our sample period using the hourly portfolio supply and demand bid curves obtained from the PX.

The next stage of our analysis computes an estimate of the market-clearing PX prices and quantities in the absence of the impact of the current RMR contracts on PX bidding behavior. Any such estimate requires a method for determining what market-clearing prices and quantities in the PX *would have been* in the absence of the incentives provided by the current RMR contracts. This in turn requires a model for how firms buying and selling in the PX would bid in the absence of the current RMR contracts. Such a model can then used to construct the aggregate PX bid curves in the absence of RMR contracts necessary to compute the counterfactual market-clearing prices and quantities. We construct these counterfactual PX demand and supply bid curves using predictions from an econometric model of bid prices as a function of the net quantity offered to infer how market participants would bid in the absence of the current RMR contracts. Our counterfactual demand and supply bid curves assume that each market participants continues to bid to supply and demand the same aggregate quantity of energy into the PX each hour. In other words, our model only allows the current RMR contracts to influence the supply and demand bid price for each quantity, not the total quantity bid in by that market participant.

There are a variety of other reasonable assumptions that could be used to construct the counterfactual aggregate PX bid curves that removes the impact of the current RMR contracts. We have tried to select the assumptions necessary to construct these counter-factual aggregate PX bid curves in ways that yield conservative estimates of the costs of the current RMR contracts. However, we recognize that another analyst, applying a different methodology, would produce a different estimate of this cost. We welcome such studies in order gauge the sensitivity of our cost numbers to the modeling assumptions we have made For these and other reasons, the MSC strongly recommends release to the public of all aggregate data associated with the day-ahead and ISO markets with a 3-month lag.

3.3.4 Extensions of Original Analysis

We have expanded the scope of our analysis in the following eight ways in order to address the concerns raised by market participants at the December meeting at FERC and the March meeting at PG&E.

(1) Model the impact of the current RMR contracts on the supply and demand bids by all participants in the PX market. As discussed above, loads have the ability to demand-side bid into PX to avoid high prices caused by less aggressive bidding by generators into the PX due to the incentives provided by the current RMR contracts. We now construct counterfactual (in the absence of demand-side and supply-side bids for all market participants, the four new RMR generation owners [Duke Energy, Dynegy, AES, and Reliant Energy (formerly Houston Industries)], the three IOUs, and a residual market participant composed of all remaining bidders.

(2) Model net supply curve of each market participant. Further motivation for removing the impacts of the current RMR contracts on both the demand-side and supply-side bids comes from an analysis of all *supply and demand bids* submitted by all market participants. We found that the vast majority of market participants submitted significant amounts of demand-side bids and were, for many hours during our sample, significant net demanders in the PX. Because the PX is a purely financial market for hedging electricity, what matters to a generator's profits is its net position in PX and the price at which it holds this position. The logic underlying this view is the following. According to the PX rules all portfolio supply bids must be piece-wise linear *increasing* functions and all portfolio demand bids must be piece-wise linear *decreasing* functions. All demand and supply portfolio bids function have a minimum price bid of \$0/MWh and maximum price bid of \$2500/MWh. Let S(p) be the firm's aggregate supply bid function and D(p) the firm's aggregate demand bid function. The PX rules allow firms to submit as many portfolio supply and demand bids as they would like for a given hour. Each of these aggregate curves for a given market participant is the sum of all of its portfolio bids for that side of the market. Define SN(p) = S(p) – D(p) as the aggregate net supply curve from that market participant for that hour at price p. Note that because both S(p) and D(p) are monotone functions, SN(p) is also a strictly increasing function according to the PX rules. Figure 27 graphically illustrates the process of constructing the net supply function for a single firm.

Because a firm can submit as many supply portfolio bids as it would like, the ability to submit demand-side portfolio bid functions is redundant so long as the net supply of the firm at price p is positive. The only increase in bidding flexibility from allowing firms to submit demand-side bids is that SN(p) can be less than zero, whereas S(p) must be greater than or equal to zero for all prices in the interval \$0/MWh to \$2,500/MWh, the set of feasible PX price bids. A negative value of SN(p) occurs at prices such that D(p) > S(p), meaning that the bidder is a net demander at price p. Given an aggregate demand bid curve D(p) and aggregate supply bid S(p), if the market-clearing price is p*, this firm has a financial commitment to SN(p*) MWh of electricity at a price of p*. If SN(p*) > 0 then the firm has hedged that amount of supply in the day-ahead market at price p*. If SN(p*) < 0 then the firm has hedged that amount of load in the day-ahead market at price p*. It is the firm's net financial position in the PX is that matters to its profitability. Consequently, each market participant's strategy for selling into the PX is neither its bid supply curve, S(p), nor its bid demand curve, D(p), but its net supply curve SN(p).[30] It should be noted that there are institutional barriers in place that are intended to prevent the coordination of the supply and demand bidding of some firms. However, a separate analysis in which we treated each firm's supply and demand bids independently did not produce significantly different results.

(3) Perform analysis with RMR calls for own-firm and RMR calls for other firms as separate variables. At the December meeting at FERC, several market participants stated that expected RMR calls for units owned by the firm would impact the generator's bidding behavior differently from RMR calls for units owned by that firm's competitors. Consequently, we now construct two separate variables for each firm for each hour called RMROWN and RMROTHER. There variables are, respectively: (1) the total quantity of gross RMR energy in that hour called from units owned by the firm, and (2) the total quantity of gross RMR energy in that hour called from all other RMR units.

(4) Perform analysis without and with contract B RMR calls. Several market participants felt that both types of the existing RMR contracts had similar incentives effects. Consequently, they felt it made no sense to distinguish between RMR calls under contract A versus those under contract A. However, as discussed above, others argued that the RMR contract B incentive should be treated more like a fixed effect, meaning that it should not vary with expected quantity of RMR energy called from contract B units. These units have little incentive to participate in the PX or ISO energy markets because they must rebate 90% of their variable operating profits from the market. To assess the sensitivity of our results to these two viewpoints, we have performed our analysis with and without including contract B RMR calls in the variables RMROWN and RMROTHER defined above.

(5) Do not use information on infra-marginal portion of aggregate net supply bid curve. In our December analysis we used the bid price at various points on the firm's aggregate supply bid curve between its bid supply quantity at a price of \$2500/MWh (q_T) and its bid supply quantity at a price of \$0/MWh (q_0). We chose four quantity points on this interval

$$q_1 = 0.3(q_T - q_0) + q_0$$
$$q_2 = 0.5(q_T - q_0) + q_0$$
$$q_3 = 0.7(q_T - q_0) + q_0$$
$$q_4 = 0.9(q_T - q_0) + q_0$$

These quantity points are located 30%, 50%, 70% and 90%, respectively, between q_0 and q_T. Using the aggregate bid supply curve for that participant for that hour, we computed the bid price associated with each of these four quantities. These are labeled p_1, p_2, p_3

[30] During our sample period, and up until March 18, 1999, the ISO did not accept negative supplemental energy bids. Consequently, when the price in the PX is zero, the net supply functions submitted by many generators caused them to be net demanders from the PX. Under these circumstances, the generators could leverage their real-time energy sales with no downside risk. A generator would sell its physical production in the real-time energy market at the real-time price. It would also clear the net demand it hedged in the PX at a price of zero by selling it back in the real market at a real-time price that is greater than or equal to zero. If the real-time price is positive, the generator earns revenues on both transactions. Note that generator incurs no energy costs to sell back the demand previously hedged in the PX at a price of zero.

and p_4 in Figure 28. Having constructed these prices and quantities for each hour during our sample period, we then used the price points and quantity levels to determine the impact of RMR contracts on price bids at each of these quantity levels. Market participants at the December meeting expressed concern that bid prices for quantities supplied below and above the market-clearing price and quantity were largely irrelevant to inferring the impact of RMR contracts. So long as bid price and quantity pairs at the market-clearing price for all market participants stayed the same, there would be no change in the PX market-clearing price and quantity. Consequently, we chose to use only one price and quantity pair from each net supply bid curve each hour—the market-clearing PX price and the net supply of the market-participant at that price.

(6) Include more control variables in the net supply price regression. Market participants noted that there are a number of reasons that generators will bid different prices depending of the hour-of-the-day, day-of-the-week, and month. Consequently, for each market participant we include a full set of indicator variables for the hour of the day, the day of the week and the month of the year in our bid price equation for each firm.

(7) Allow for nonlinear relationship between ISO load forecast and bid price. During the March meeting at Pacific Gas and Electric, several market participants stated that the level of ISO load would impact a market participant's bid price in a nonlinear manner. We include the ISO load forecast for that hour as explanatory variable in the regression of the bid price for that hour on the net quantity supplied in that hour in order to account for the expected relative scarcity of generating capacity in high load periods versus low load periods. If market participants expect that generating capacity will be scarce in the California market during a specific hour because of expectations of a high total ISO load for that hour, generators with market power (the ability to raise the market price through their bids) will bid higher prices. We do not want to attribute these higher bids caused market power having nothing to do with the bidding incentives created by the current RMR contracts to be attributed to the current RMR contracts. The best way to avoid this incorrect attribution is to specify the relationship between the ISO load forecast and the market participant's bid price as flexibly as possible. For this reason, we include the level, the square, and cube of the day-ahead ISO load forecast for that hour in the bid price equation.

(8) Allow for nonlinear relationship between net quantity supplied and bid price. We would expect that the larger the quantity of electricity a market participant wishes to hedge in the PX market the further it will be moving up its marginal cost function for supplying electricity. The opposite logic holds for a net demander from the PX. The greater the amount of load a firm wishes to hedge the less should be its willingness pay to hedge an additional unit of energy in the PX. We therefore expect the relationship between the bid price and net supply, negative or positive, of a market participant to be an increasing nonlinear function. To account for this nonlinearity in the relationship between bid price and net supply we include level, the square and the cube of the net supply from the market participant in that hour in our bid price regression.

3.3.5 Computing Counterfactual Demand and Supply Bid Functions

The next step in our analysis *removes* the influence of RMR contracts on both the demand and supply bids of each market participant and a constructs new (no RMR contract) aggregate supply bid and demand bid curves for each market participant. We explain this procedure briefly below and in detail in Appendix A.

Given these new aggregate demand and supply bid curves which remove the bidding incentives caused by the current RMR contracts for each market participant, 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 RMR contracts. Note that because we adjust both the aggregate demand and supply bid curves for each market participant for the impacts of the current RMR contracts, both the PX market demand curve and market supply curve shift. Figure 29 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 shown in this figure. The intersection of these two curves is the point (PXQP, PXPP).

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 29, which can be expressed as:

Increased Costs Purchasing Actual PX Quantity = (PXP – PXPP)*PXQ.

The second calculation of the costs of the current RMR contracts relies on a belief held by many of the market participants at the March meeting that the differences in prices between the real-time energy market and PX will tend to zero because of the arbitrage behavior of suppliers and loads across these two markets. The logic underlying this belief is that suppliers try to sell in the market with the highest prices, and loads will attempt to purchase in the market with the lowest prices. This process implies an average price difference across the two markets approximately equal zero. To investigate this hypothesis, Table 2 contains the monthly mean of the hourly day-ahead PX zonal prices and hourly real-time, or ‘imbalance,’ energy prices for the NP15 and SP15 congestion zones. The table also presents the mean and standard deviation of the hourly difference between these two prices for the same congestion zone. A formal statistical test that this price difference is zero for the same congestion zone and same month rejects the null hypothesis for all of the months besides December 1998 for both congestion zones. However, the standard deviations of the differences are sufficiently large that assuming the mean of this difference is zero may not be an unacceptable working hypothesis, particularly for December 1998.

NP15 Congestion Zone				
Month	Prices in ($/MWH)		PX Price – ISO Price ($/MWH)	
	PX	ISO	Mean	Standard Dev.
June	12.25	8.38	3.86	9.68
July	32.51	26.08	6.43	29.57
August	38.80	45.39	-6.59	36.92
September	33.97	40.77	-6.80	30.26
October	27.85	35.24	-7.39	9.96
November	27.24	30.57	-3.34	6.68
December	30.42	29.58	0.84	20.37
SP15 Congestion Zone				
Month	Prices in ($/MWH)		PX Price – ISO Price ($/MWH)	
	PX	ISO	Mean	Standard Dev.
June	12.34	8.38	3.95	9.42
July	33.14	25.98	7.16	30.25
August	39.96	43.53	-3.56	36.96
September	33.24	35.13	-1.88	29.68
October	23.92	27.78	-3.85	11.28
November	22.91	24.08	-1.16	7.84
December	26.73	26.13	0.60	17.96

Table 2: Zonal PX and Real-Time Energy Prices (Time Weighted)

Suppose that in the absence of the bidding incentives provided by the current RMR contracts, loads and generators arbitrage across the two markets to make the mean difference prices across the two markets approximately equal to zero. 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 hourly increased cost of purchasing hourly total ISO Load caused by the current RMR contracts. Because must-take generation is contracted at price outside the PX market, we exclude this quantity of electricity from our calculation of the total increased energy costs created by the current RMR contracts. Figure 30 shows this quantity graphically. Each hour we compute

Increased Cost of Flexible 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.

3.3.6 Impact of Current RMR contracts on Bid Prices

Our strategy for computing the impact of the current RMR contracts on the price a market participant bids a certain net supply into the PX market utilizes the variation across hours and days in the prices bid by market participants for a given net quantity of energy supplied. By estimating this relationship between bid price and the net quantity supplied for each market participant controlling for the quantity RMR calls by units owned by that firm, the quantity of RMR calls by all other firms, the day-ahead ISO load forecast and a variety of hour, day and month indicator variables, we can recover a prediction of the percentage reduction in both supply and demand bid prices each hour during our sample period for each market participant as a result of the elimination of the opportunity cost of the current RMR contracts.

Our procedure for accounting for the impact of RMR contracts first estimates a linear econometric model using data from the actual hourly PX aggregate net supply bid curves for each PX market participant. For each market participant, we econometrically estimate the relationship between the market-clearing PX price in that hour and the net supply by that market participant at this price, controlling for all the observable factors that might influence the bid prices a market participant would submit. These observable factors are the ISO load forecast for that hour, the generator's forecast of total RMR contract calls for that hour from units the market participant owns, the generator's forecast of total RMR contract calls for that hour from units owned by all other market participants, and a full set of hour, day and month dummy variables.

These regression equations allow us to compute a predicted effect of the current RMR contracts on the bid price for each net supply level during each hour of our sample for each market participant. We use these factors to adjust all supply and demand price bids in all portfolio bids submitted by that market participant. Figure 31 shows how this process would work in terms of aggregate demand bid function and aggregate supply bid function for a given market participant. The curve S^{actual} is the actual aggregate PX bid supply curve for the market participant. The curve $S^{predict}$ is the aggregate PX bid supply curve for the market participant adjusted by our factor which removes the impact of the current RMR contracts on the prices that market participant bids. The curves D^{actual} and $D^{predicted}$ are defined in analogous fashion for the market participant's aggregate demand bid curve. Because our factor adjusts all interior price bids (those between $0/MWh and $2500/MWh) associated with the net supply function of the market participant, this equivalent to adjusting all interior price bids associated with all portfolio demand and supply bids during that hour for that market participant.

3.3.7 Results

As noted earlier, we perform our analysis for two cases. The first case does not distinguish between contract A and contract B RMR calls. In this case we construct the variables RMROWN and RMROTHER as, respectively, total A and B RMR contract calls for that hour from units the market participant owns and total A and B RMR contract calls for that hour from units owned by all other market participants. We call this the Combined Analysis Scenario. The second case, which we believe is the correct measure of the impact of the contract A on generator bidding behavior, excludes contract B RMR calls from the variables RMROWN and RMROTHER. We call this the Contract A Scenario. For each scenario we compute our increased PX cost estimate and our increased cost of purchasing flexible ISO load estimate.

We first consider the Combined Analysis scenario. We believe this scenario yields a downward-biased estimate of the costs of RMR contracts, because, as noted earlier, contract B units should not have an opportunity cost of bidding into the PX market because they are paid an estimate of their variable cost for an RMR call. Only to the extent that this estimate is above the unit's true variable cost is there any forgone net revenue from an RMR call similar to what occurs under a contract A RMR call. In addition, these unit owners must refund 90% of their net revenues from market sales. This reduces the incentives for these units to participate in the PX. Consequently, we would not expect changes in the level of RMR B calls to cause noticeable changes in the bid prices of contract B units into the PX market. Therefore, in the Combined Analysis scenario we are measuring the impact of changes in the sum contract A RMR calls, which should affect bid prices, and contract B RMR calls, which should affect bid prices significantly less, on bid prices. If, only changes in the amount of contract A RMR calls significantly affect bid prices, our estimate of the effect of a one unit change in total RMR calls will be smaller than the true effect of a one unit change in contract A RMR calls. This result occurs because a one unit change in total RMR calls results in less than a one unit change in contract A RMR calls for all hours but those in June.

Table 3 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 for both modeling scenarios. As expected, the Combined Analysis Scenario figures are below the Contract A Scenario figures for each month and each hour.

Month	Average Hourly Increased Costs Due to Current RMR Contracts in (Millions of Dollars)—Combined Analysis Scenario	
	Increased Cost to Purchase PXQ	Increased Cost of ISO Load – Q(MT)
June	0.03	0.02
July	0.11	0.08
August	0.14	0.11
September	0.10	0.07
Month	Average Hourly Increased Costs Due to Current RMR Contracts in (Millions of Dollars)—Contract A Scenario	
	Increased Cost to Purchase PXQ	Increased Cost of ISO Load – Q(MT)
June	0.06	0.03
July	0.17	0.12
August	0.23	0.18
September	0.15	0.11

Table 3: Cost Impacts of Current RMR Contracts

We report these magnitudes at this level of precision because this is the degree of accuracy of our sensitivity analysis indicated was in the numbers. Because our current methodology assumes no capacity withholding from the PX market, we expect these estimates to be very conservative, in light of the evidence in Figures 11-18.

4 Summary

In the previous section, we have presented data indicating that because of the design of the current RMR contracts, market participants have not bid as aggressively in the PX market as they would have in the absence of the bidding incentives created by the structure of these contracts. We now consider the implications of these findings for the design of new RMR contracts.

4.1 Recommendations

As the Market Surveillance Committee (MSC) has stated in its earlier discussions on this subject, it is best to explicitly recognize that RMR contracts are by definition 'out of market' arrangements between the ISO (and transmission owners) and certain generators. These units have local market power in the sense that under certain grid contingencies they are required to run for local grid reliability reasons. They are the only (or one of a very small number of) available suppliers of these local grid reliability services. The RMR contract is therefore an agreement to provide these services at regulated prices because of the extreme local monopoly or oligopoly power possessed by these units in providing these services. The price of electricity supplied by the vertically integrated electric utility was regulated in the old geographic monopoly regime for the same reason that these local reliability services must be supplied at regulated prices.

Therefore, without local grid reliability services provided at regulated prices, it makes little sense to attempt to run a competitive market for electricity in California for the current configuration of the California grid and set of available generation capacity. During those periods when certain generation facilities are needed for local grid reliability needs, the relevant plants can bid any price still be dispatched. One can therefore think of these local grid reliability services as facilitators of a competitive market for electricity supply. Given this perspective, it is best to make payments for the provision of these local grid reliability services to minimize their impact on the workings of the energy and ancillary services markets. This implies making fixed payments to generators in exchange for operating conditions, so that their bidding incentives into the PX and ISO markets are unaffected by their RMR status. Any compensation scheme for RMR energy that creates an opportunity cost to bidding into the PX or any ancillary services market may be used by an RMR unit owner to leverage local market power into greater market power in the PX and ancillary services market. The goal in designing an RMR compensation scheme is to prevent such a leveraging of local market power.

The type of contract that meets these goals is a pure option contract, with periodic (monthly or annual) fixed payments with no requirements for a rebate of deemed profits. The size of the fixed payment made to RMR generators is, to a large extent, a subject of negotiation and regulation. There are however, several economic principles that can inform these negotiations over the size of the fixed payment received by RMR generators. These principles include:

1. **Pre-existing (sunk) capital costs** should not be used as a basis for RMR payments. The purpose of RMR contracts is to compensate certain generation units in such a way that ensures their continued operation, which has been deemed essential for reliability purposes. Pre-existing capital costs, being sunk, have nothing to do with an economic decision to continue operation of a plant.
2. **Fixed costs** associated with the going forward operation of the generation unit should play a role in the calculation of a fixed RMR payment. Because some units are expected to be 'must-run' for reliability purposes far more often than others, the percentage of annual fixed costs included in these payments may need to be scaled in some way that reflects the relative contribution of each plant to system reliability during the year.
3. Stakeholders may or may not decide that **opportunity costs**, such as forgone market revenues from energy or ancillary services markets should be incorporated into fixed RMR payments. The special status of these units also entails special responsibilities. In our opinion, the fixed subsidies received for continued operation represent a *quid pro quo* for some degree of forgone market revenues. If it is decided that RMR units must be compensated for opportunity costs, however, we strongly recommend that this compensation be in the form of fixed payments, rather than an energy payment linked to specific, hourly market outcomes. The fact remains that, at certain times, a large fraction of a plant's capacity is required for local reliability purposes, so that at these times such units simply cannot provide ancillary services. If they cannot provide these services, they should not be allowed, or given the incentive to, influence the market prices of these services.
4. Unit **start-up costs** represent a difficult incentive problem. On the one hand, generation units profit from having these start-up costs, including ramp-up and ramp-down costs, covered by RMR payments, regardless of the rate paid for RMR energy, and may therefore adjust their market bids accordingly. On the other hand, generation units fear that the ISO, if it were not responsible for start-up costs, may call on these units more than just for grid reliability reasons. The best way to resolve the incentive problems on both sides is to incorporate expected start-up expenses into the fixed annual payments made to units. Unit owners would receive an fixed annual payment based on the expected number of startups for local reliability needs that is independent of the number of times the unit is actually started-up or called to provide energy or ancillary services under its RMR contract. Under this scheme, unit owners are liable for the full cost of all start-ups they incur whether it is to provide RMR energy, or energy or ancillary services through any of the PX or ISO markets. Generator decisions on market bidding and participation would therefore not be influenced by the payment for start-up costs associated with an RMR energy or ancillary services calls versus the lack of any explicit payment for start-up costs for supplying energy or ancillary services into a PX or ISO market. The current RMR contract regime pays for the start-up costs associated with an RMR call if the unit is currently shut down. A generator can use knowledge of the timing of its unit's RMR energy calls to determine the timing the unit's shutdowns so that a large fraction of the unit's start-up costs are covered by its RMR contract. The amount added to the fixed payments that is linked to RMR specific start-up costs could be periodically re-

adjusted to both correct inaccuracies in the forecasted start-ups for that unit and to provide an incentive to the ISO to mitigate the number of starts needed for RMRs.

The protocols for the operation of RMR units have also been a subject of the current negotiations. The issues in question include the conditions under which units can be called under RMR contracts and the payments that they receive for each unit of energy provided under RMR. On these questions, we advise the following:

1. Must-run energy needs, which are based upon load forecast and physical system conditions, should be made public before the day-ahead energy and ancillary services markets are held.
2. The per-unit of energy or ancillary services variable rate of compensation for providing RMR energy or ancillary services should be the marginal cost associated with providing that energy or ancillary service. In the case of ancillary services, unless a generator can satisfactorily demonstrate a causal relationship between providing one more 1 MW of a ancillary service from a unit an increase in that unit's costs, the marginal cost of that service for that unit should be assumed to be zero.
3. The owners of the generation that has been declared to be must-run should at this point decide whether they wish to receive, as their RMR variable compensation, their respective RMR variable rates or the as yet undetermined PX price for that hour for their RMR energy. Any sort of higher of RMR and PX or ISO market price should be avoided for the reasons that it can provide RMR generators with incentives to leverage their locational market power and raise prices in the PX or ISO markets.
4. The total RMR supply for that hour should then be treated in the same way as regulatory must-take capacity in the PX bid curve, because it is a regulated service that has already been paid for with the up-front payment. Consequently, it should therefore be a price-taker in the PX market. Alternatively, owners that are declared must-run can submit to the ISO a balanced day-ahead energy schedule which includes at least the RMR quantity of energy from each of the plants called to provide local reliability services during that hour.

The impacts of RMRs payment schemes on bidding incentives can, and have, had a significant impact on market-clearing prices. Given the significance of these impacts, it is important to de-couple, as much as is possible, reliability must-run requirements from the performance of the broader markets. It is therefore much less risky to err on the size of fixed payment commitments rather than on the notion that a fair compensation for must-run generation must be linked to hourly market performance. Linking payments for RMR services to hourly market outcomes runs a real risk that locational market power can be leveraged to yield higher market prices for all energy and ancillary services purchased from PX and ISO markets. Such a linkage between RMR payments and market outcomes therefore unnecessarily increases market prices and total electricity supply costs for final consumers.

An additional advantage of up-front payments for all non-variable cost RMR services is the transparency of the non-variable cost payments received by RMR unit owners to current and potential generation entrants and current regional transmission operators.

The ultimate aim of the ISO is to eliminate as many of these RMR units from the California market as rapidly as possible without reducing system reliability. This will be most rapidly and efficiently accomplished if the costs of providing these services are transparent to all market participants. If the above-marginal cost payments made to RMR generation for the services they provide are made in the form of a single up-front payment known to current and potential market participants, instead of as a complicated per unit payment scheme which depends on the number of times a generator is called under the contract and its market revenues, the economic signals for new generation plant location or where grid expansion or enhancement should occur will be much stronger. Under this up-front payment scheme new entry and/or grid expansion should take place where these up-front payments are the highest. Under this scheme, California should more rapidly progress to the efficient competitive market all participants desire.

Appendix A: Calculating the Impact of RMR Contracts on Bid Prices

For all market participants we perform the following set of calculations. For each hour compute the net supply curve of that market participant for that hour. An example of such a net supply bid curve is given in Figure 27. We then read off the net quantity supplied at the PX market-clearing price for that hour. On Figure 27, this net supply is denoted by SN_{PXP} and the PX marking-clearing price by PXP. 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. It is constructed by taking the net supply bid at each price from all supply and demand portfolio bid curves submitted by that market participant during that hour. Consequently, although this curve is piecewise linear, it can contain many interpolation points because most participants submit a number of portfolio bid curves each hour.

For each market participant, i, and each hour, j, of each day, k, define the following notation:

$SN_{ijk} = S_{ijk}(PXP_{jk}) - D_{ijk}(PXP_{jk})$, the net supply by firm i in hour j of day k at the PX price for that same hour and day.

$RMROWN_{ijk}$ = 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

$y_{jk} = \ln(PXP_{ijk} + 1)$ = the natural log of the PX price plus 1 for hour j of day k. (Because the PX price is sometimes equal to zero we must translate it by 1 before taking the log.)

$DA\_ISO\_LOAD_{jk}$ = the day-ahead ISO 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=1,2,3,4 corresponds to June, July, August and September

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 to Saturday

$HOUR_{jh}$ = 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

For each market participant, estimate the following regression equation for firm i for all days (k) and hours (j) over the four month period from June to September:

$$y_{jk} = \alpha + \sum_{a=1}^{3} \gamma_a (SN_{ijk})^a + \sum_{b=2}^{4} \delta_b MONTH_{kb} + \sum_{c=2}^{7} \eta_b DAY_{kc} + \sum_{d=2}^{24} \omega_d HOUR_{jd} \quad (1)$$

$$+ \beta_1 RMROWN_{ijk} + \beta_2 RMROTHER_{ijk} + \sum_{g=1}^{3} \phi_g (DA\_ISO\_LOAD_{ijk})^g + \varepsilon_{ijk}$$

We estimate the parameters of this model by two-stage least squares (2SLS) using DA_ISO_LOAD, $(DA\_ISO\_LOAD)^2$ and $(DA\_ISO\_LOAD)^3$ for all other hours in day k as instruments for RMR and RMROTHER, because these two variables are unknown at the time the generator submits its net supply curve into the PX. The time path of total ISO load throughout the day should impact RMR calls in each hour of the day. Consequently, we assume 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 for all hours of the day in addition to all of the remaining variables in equation (1) besides RMROWN and RMROTHER. For majority of the market participants these first-stage regressions forecast the values of both RMROWN and RMROTHER quite well. The first-stage regressions are computed by regressing 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 and RMROTHER from these two regressions are then substituted into (1), and this equation is estimated by ordinary least squares.

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, 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 (1), but our estimation and counterfactual PX price calculations did not significantly change.

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

$$\beta_1 RMROWN_{ijk} + \beta_2 RMROTHER_{ijk}$$

as $X_{ijk}'\theta$ where X_{ijk} is the vector of regressors and θ is the vector of coefficients. Take the exponential function of both sides of this equation:

$$p_{ijk} + 1 = \exp(X_{ijk}'\theta + \epsilon_{ijk}) \exp(\beta_1 RMROWN_{ijk} + \beta_2 RMROTHER_{ijk})$$

To adjust for the impact of the opportunity cost of RMR contracts on the bidding behavior of this firm, we set the predicted value of RMROWN and RMROTHER equal to zero, so that

$$p_{ijk} + 1 = \exp(X_{ijk}'\theta + \epsilon_{ijk}),$$

because exp(0) = 1. The term

$$C(i,j,k) = \exp(\beta_1(RMROWN_{ijk})^{pred} + \beta_2(RMROTHER_{ijk})^{pred})$$

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)'s that are greater than 1. In fact, for some hours and market participants the values of C(i,j,k) are greater than one.

The variables $(RMROWN)^{pred}$ and $(RMROTHER)^{pred}$ in C(i,j,k) are the predicted values from first-stage regression described above. RMR and RMROTHER must be forecast by the firm in the net supply bid price function in equation (1) because these two variables are unknown to the market participant at the time its bids a net supply curve into the PX.

We apply this factor to all bid prices, pbid, for all interior demand and supply portfolio bids prices (all bids except those 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. This yields

$$pbid_{ijk}^{NO\ RMR} = ((pbid_{ijk} + 1)/C(i,j,k)) - 1$$

We repeat this procedure for the following four reliability must-run generation owners the three IOUs, and a residual market participant composed of the bids of all remaining market participants. For firms that do not own any RMR units, we do not include the regressor RMROWN. For these units RMROTHER is the total quantity of RMR calls in that hour of that day.

For the Contract A Scenario, we re-run this analysis for the following definitions for our RMR variables:

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

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

For firms that do not own any contract A RMR units, we do not include the regressor RMROWN. For these units RMROTHER is the total quantity of contract A RMR calls in that hour of that day. We compute the RMR contract A adjustment factors following the same procedure as outlined above for these definitions of RMROWN and RMROTHER.

FIGURE 1: The Must-run Problem

Geographic Distribution of Supply and Demand

System-wide Aggregate Supply and Demand

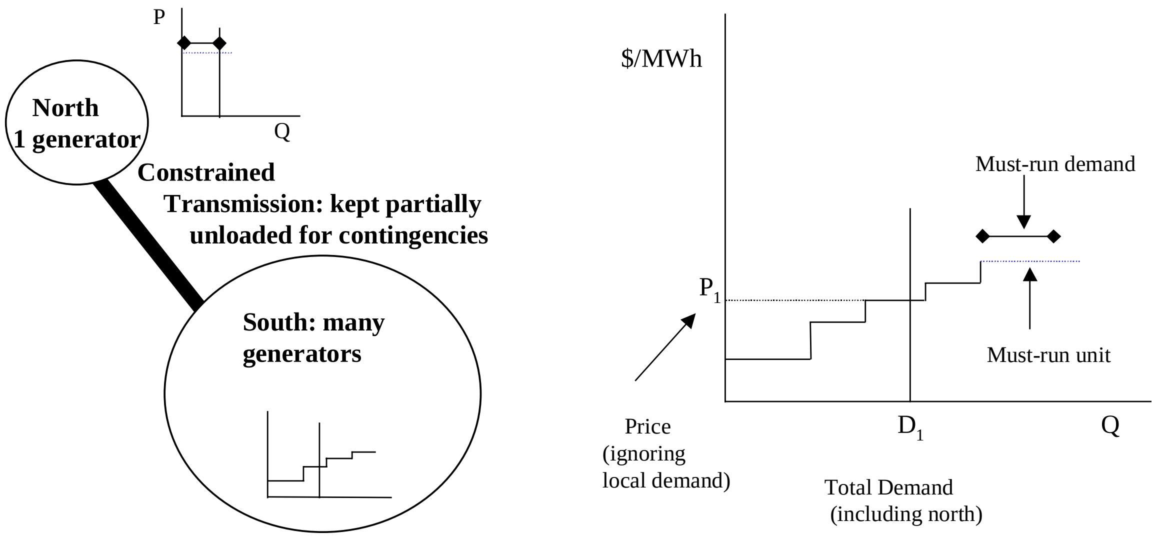


FIGURE 2: RMR Impact on Market-Clearing Price

System-wide Aggregate Supply and Demand

System-wide Supply and Demand: after meeting must-run demand

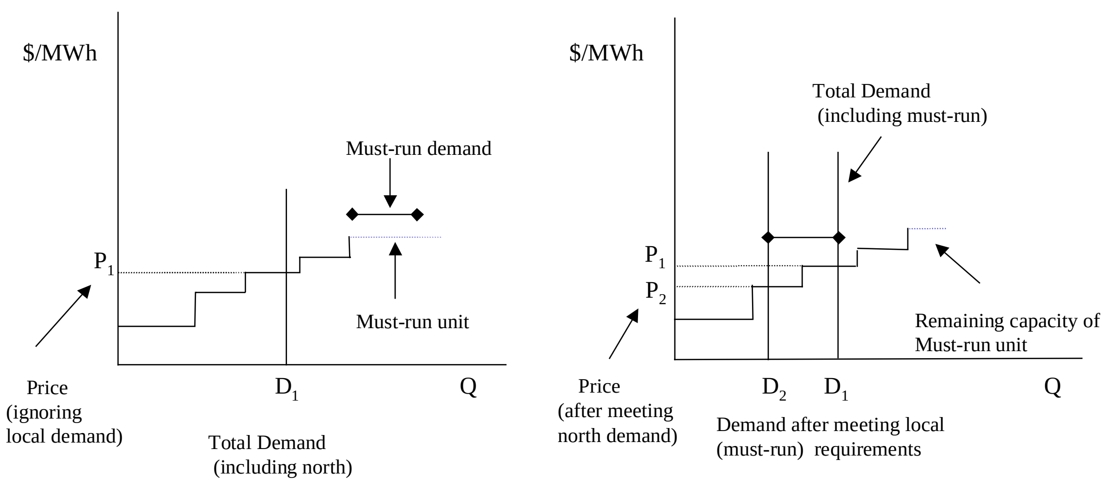


FIGURE 3

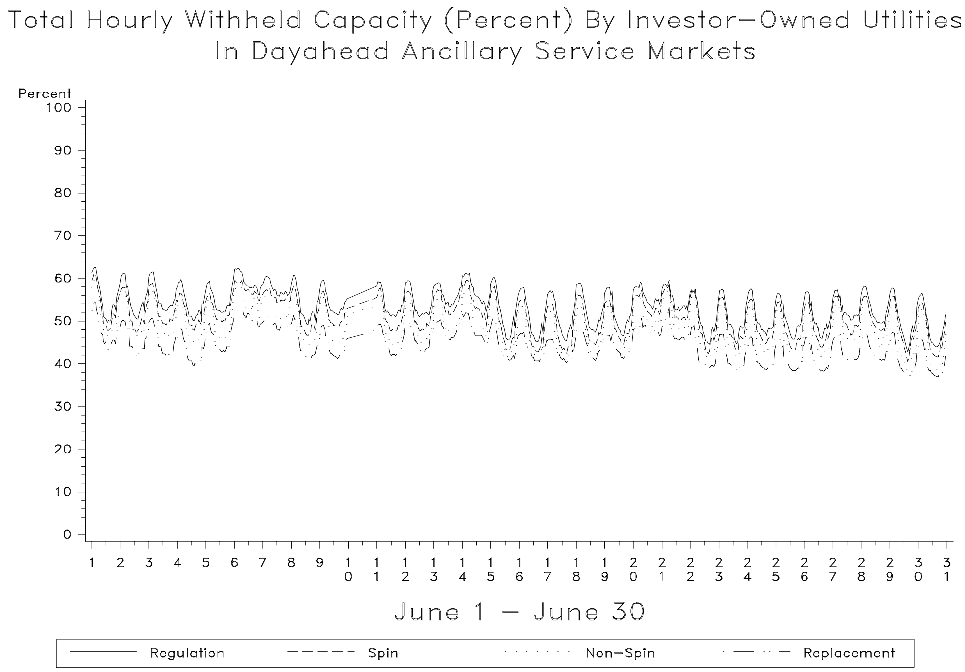


FIGURE 4

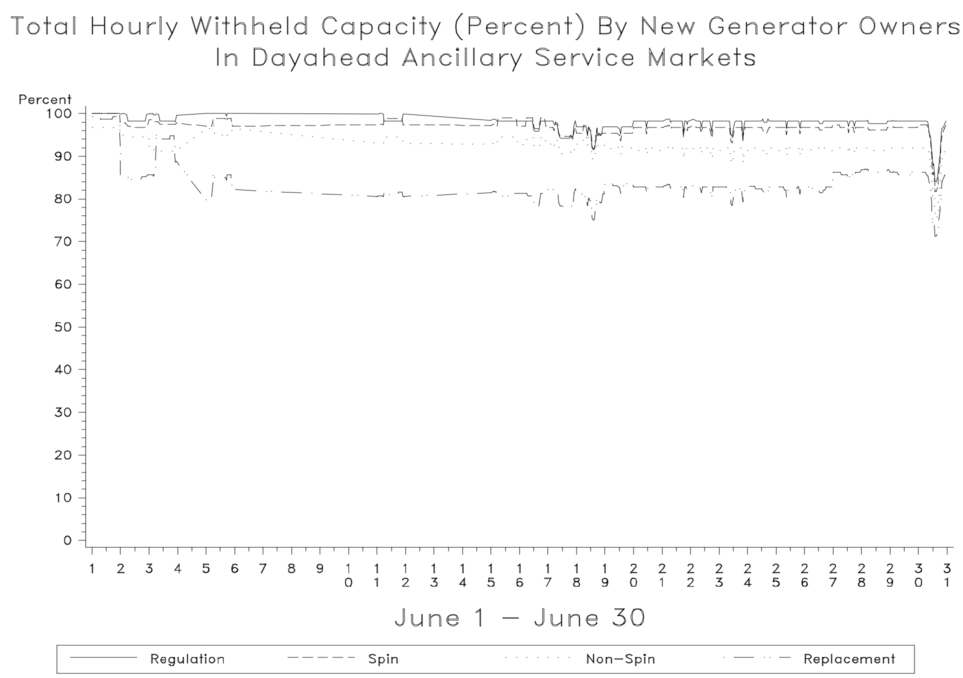


FIGURE 5

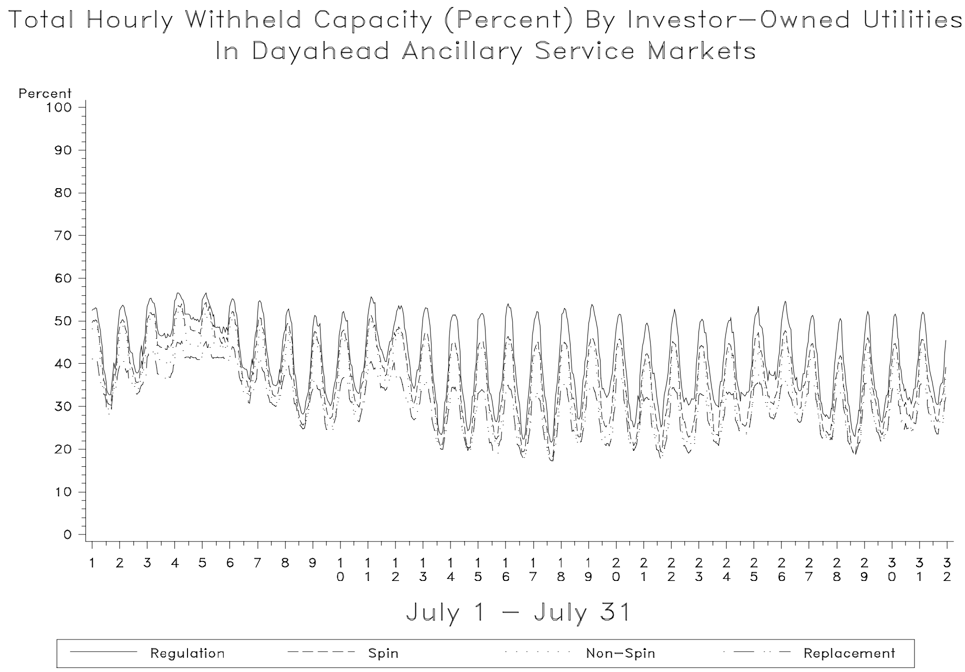


FIGURE 6

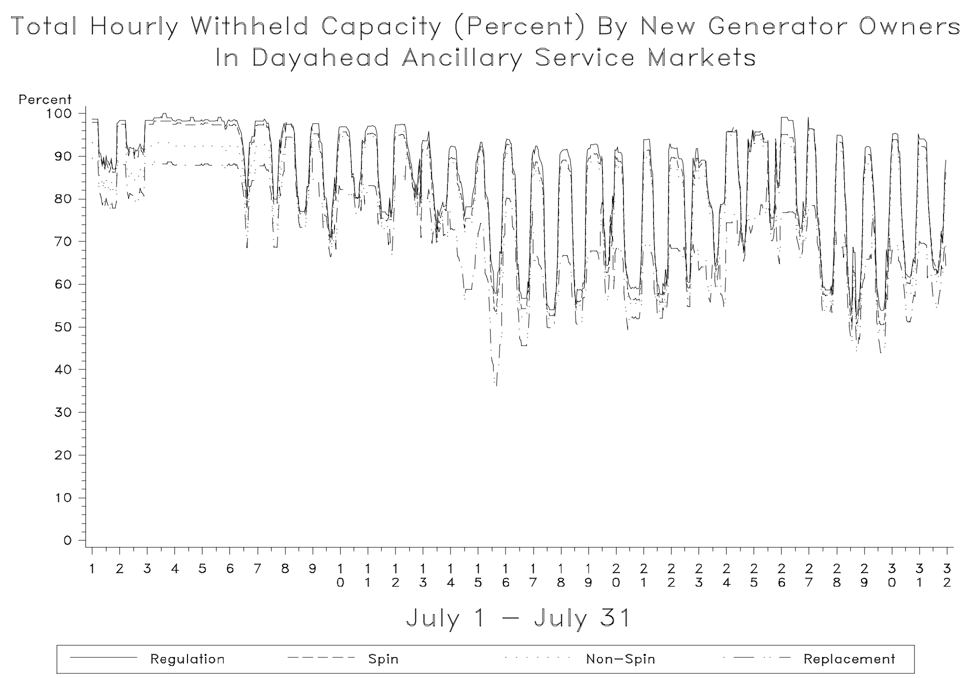
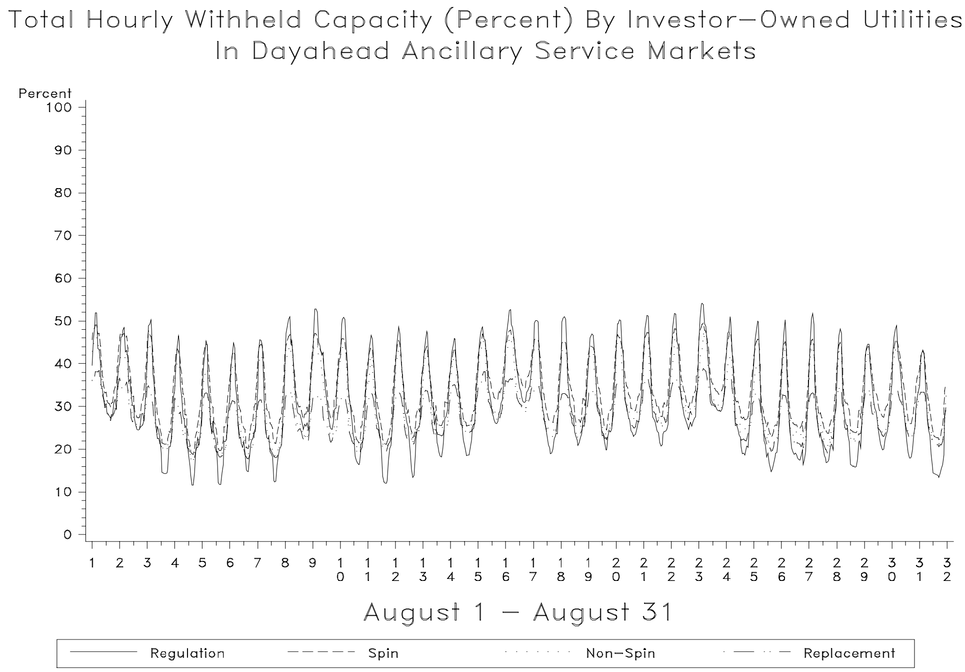


FIGURE 7



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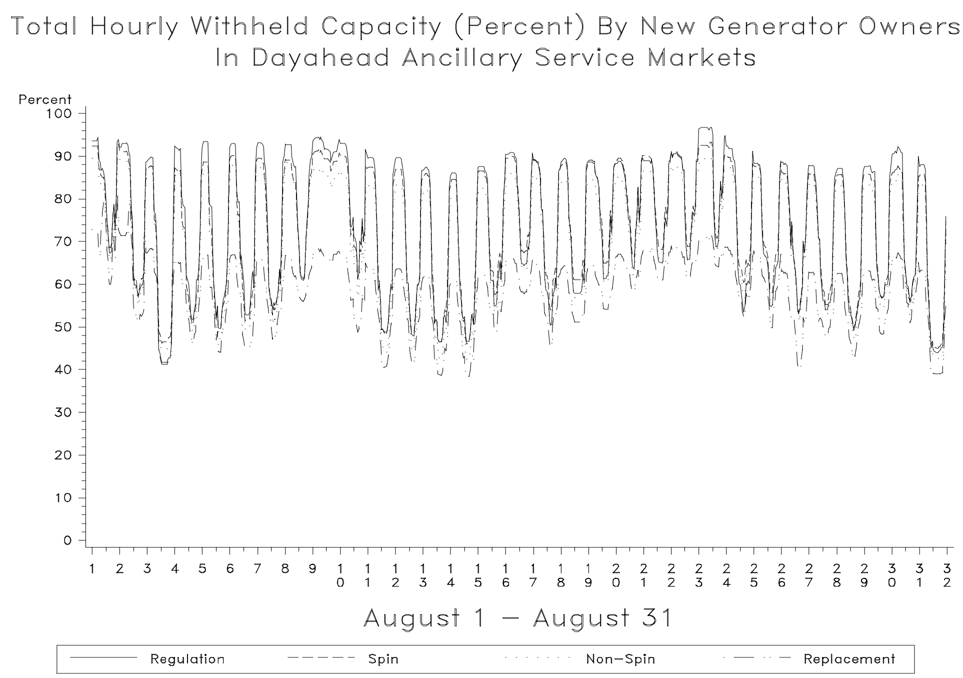

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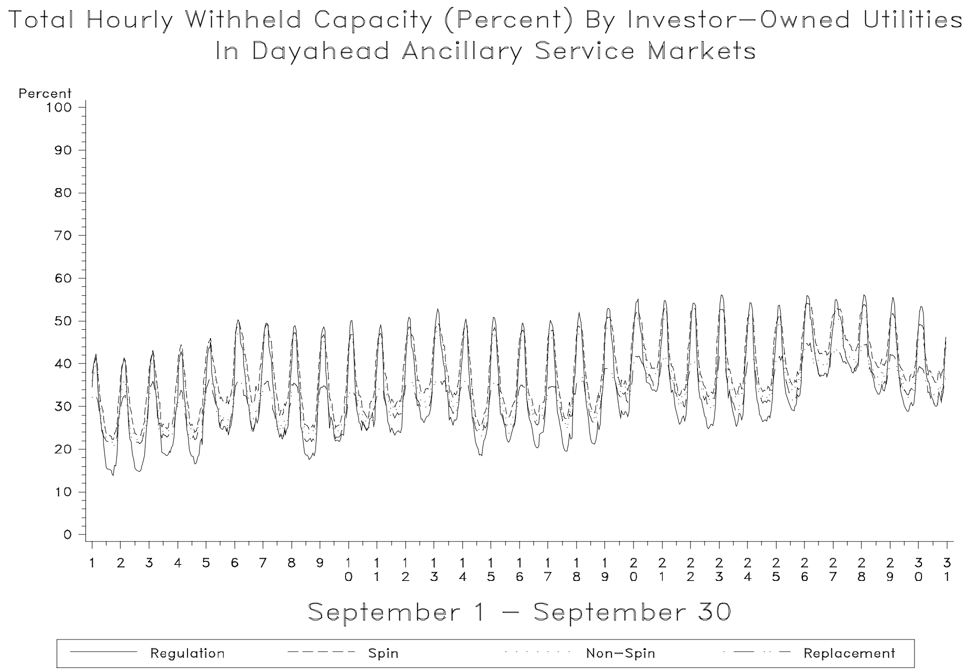

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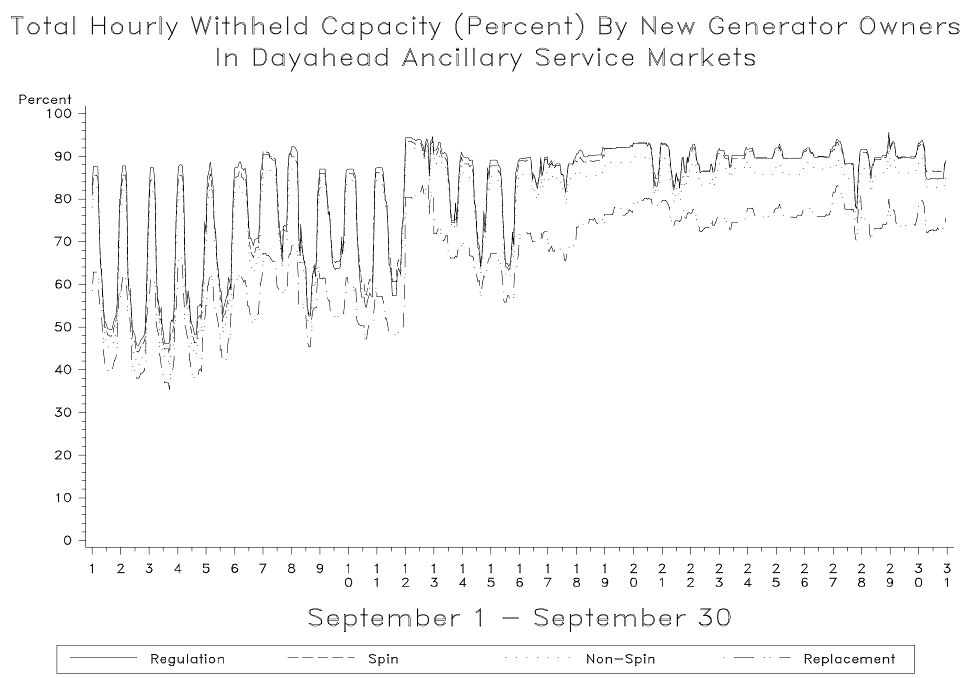

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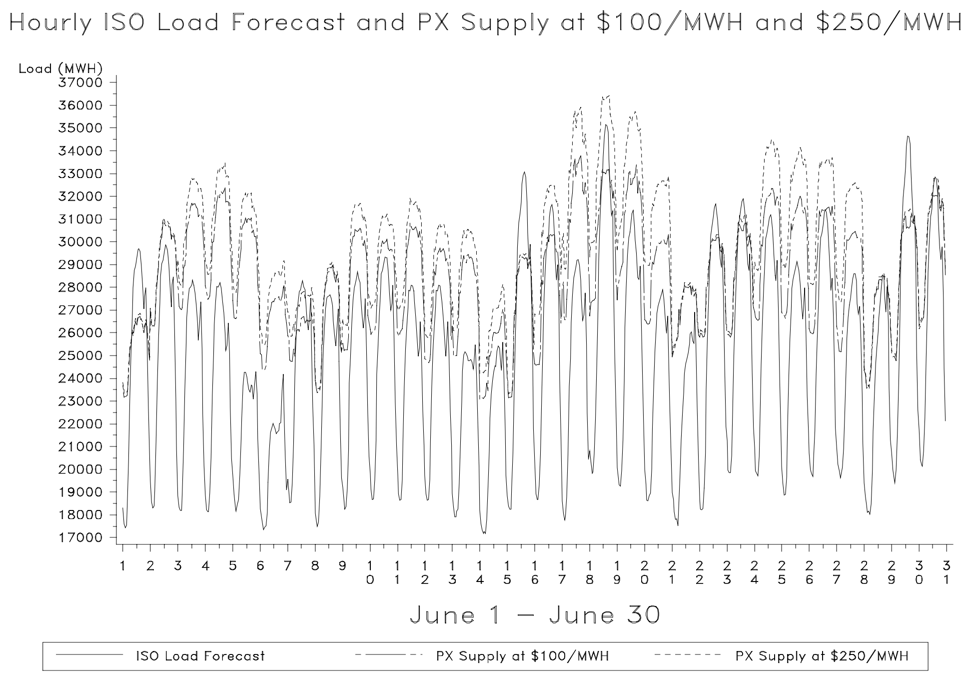

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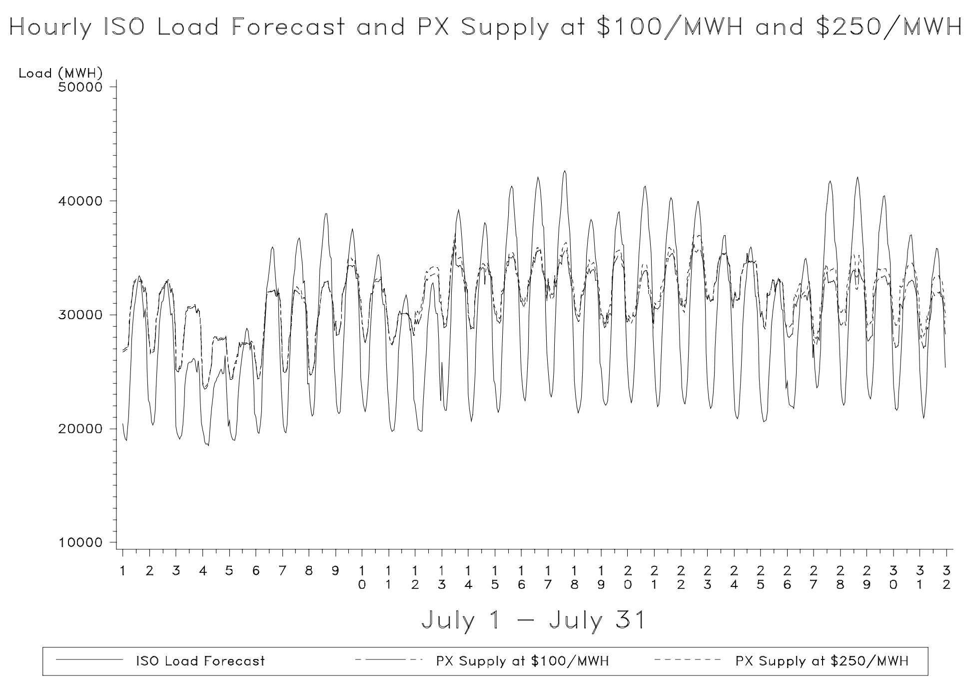

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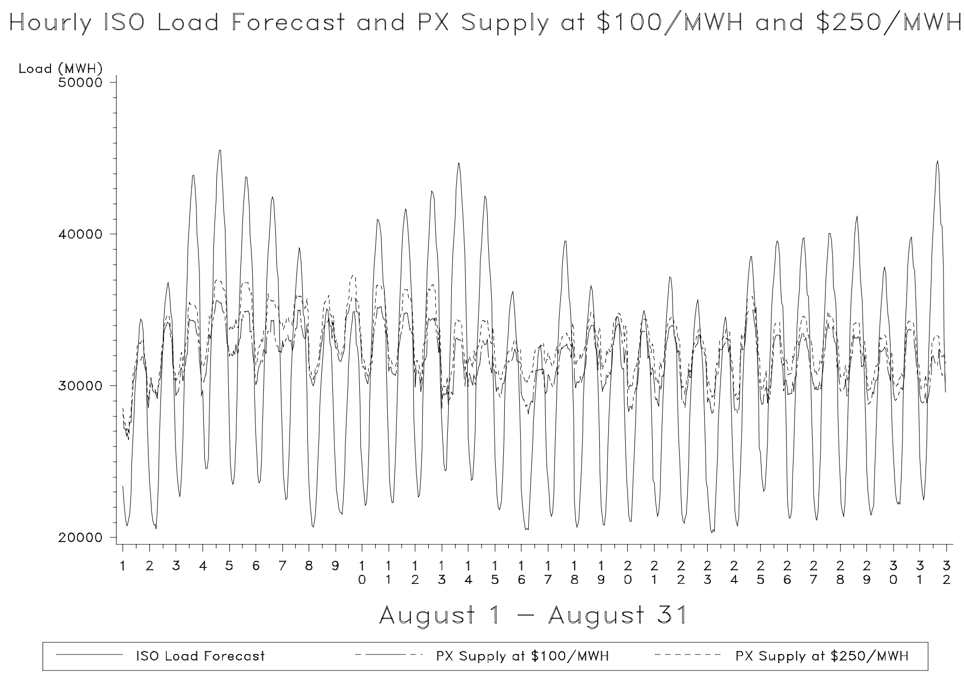

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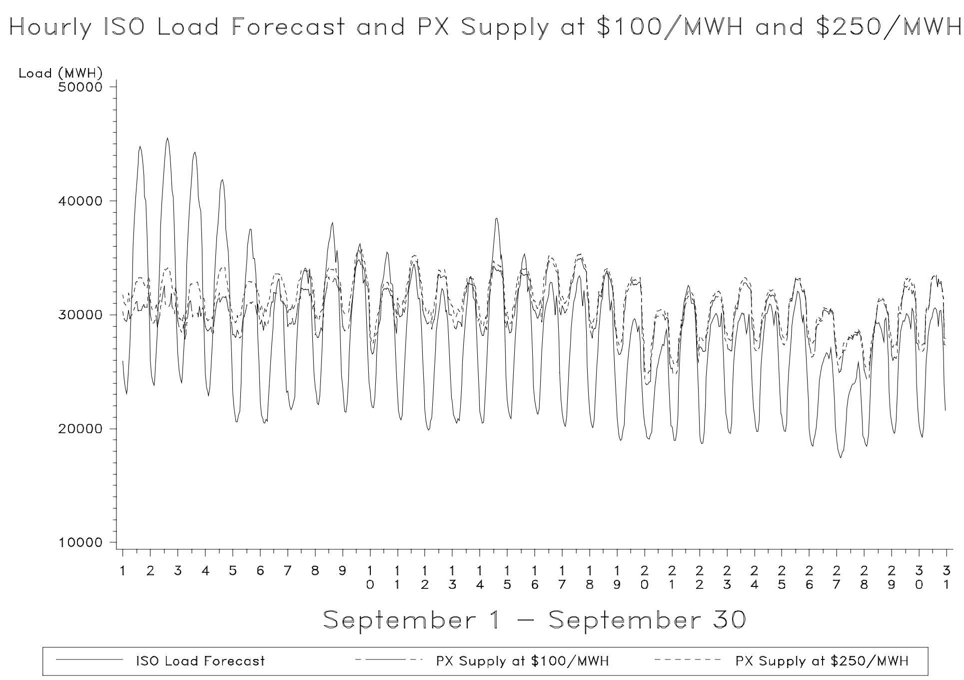


FIGURE 15

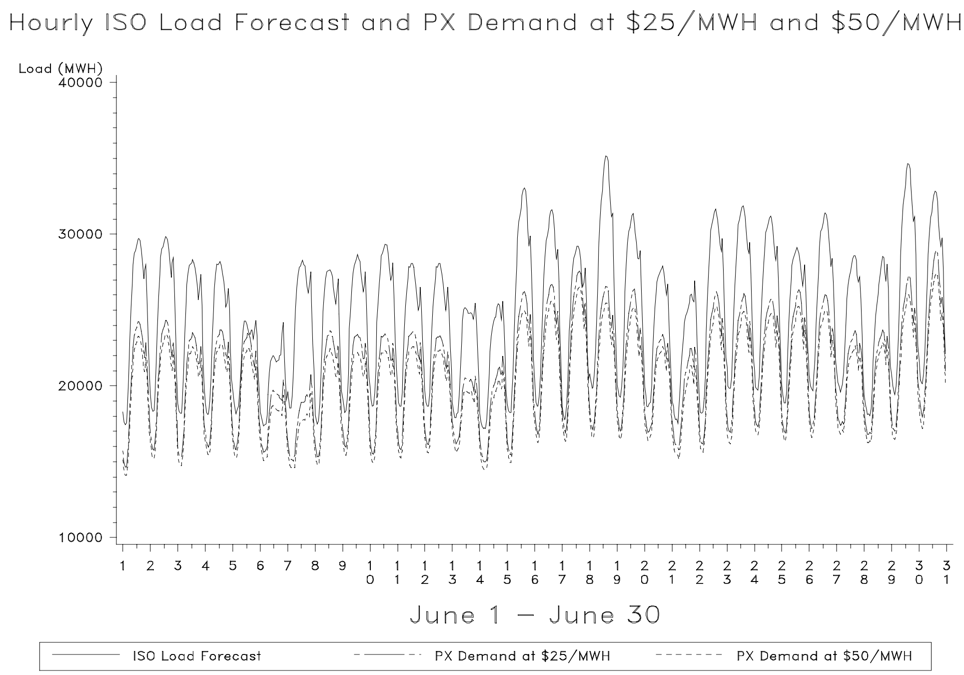
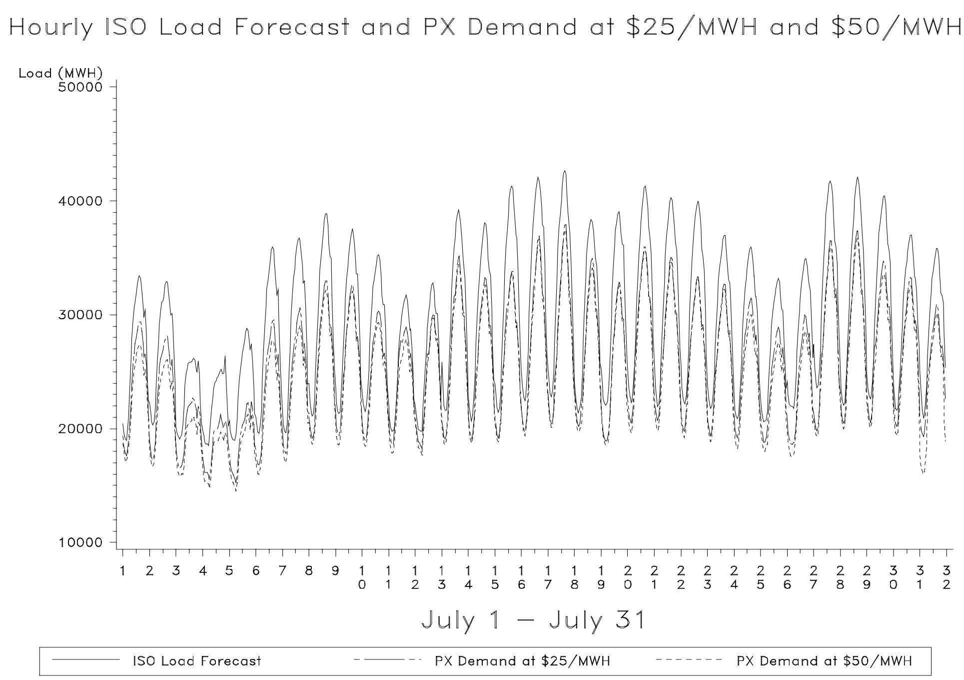


FIGURE 16



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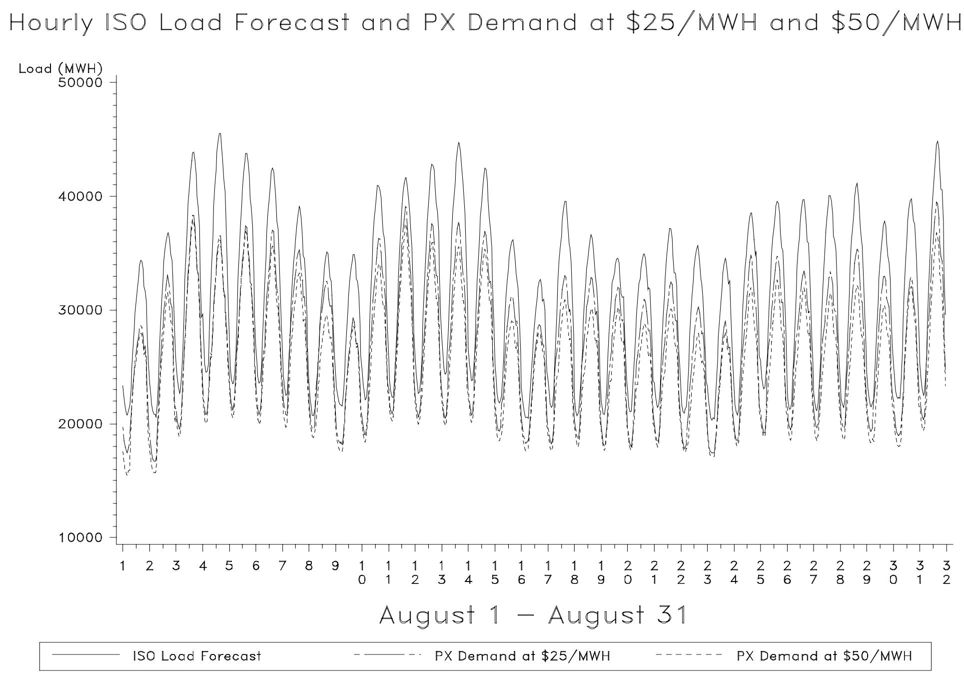

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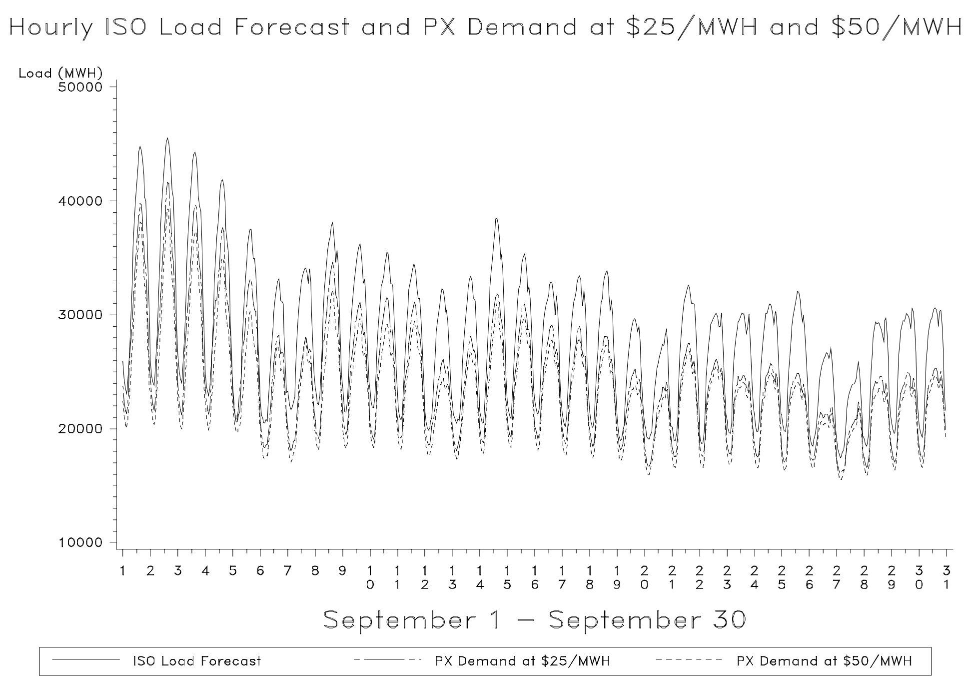

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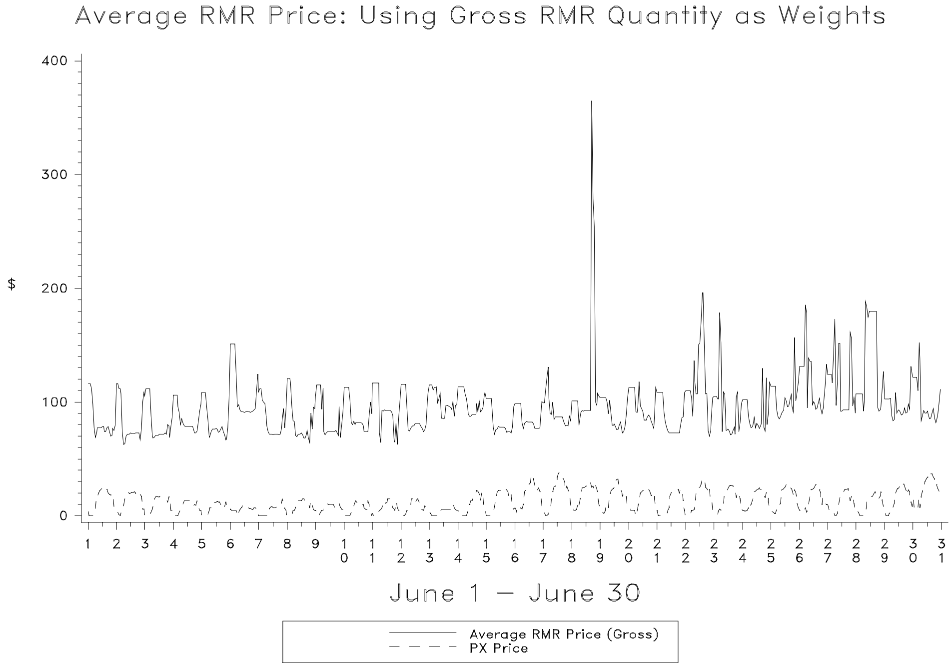

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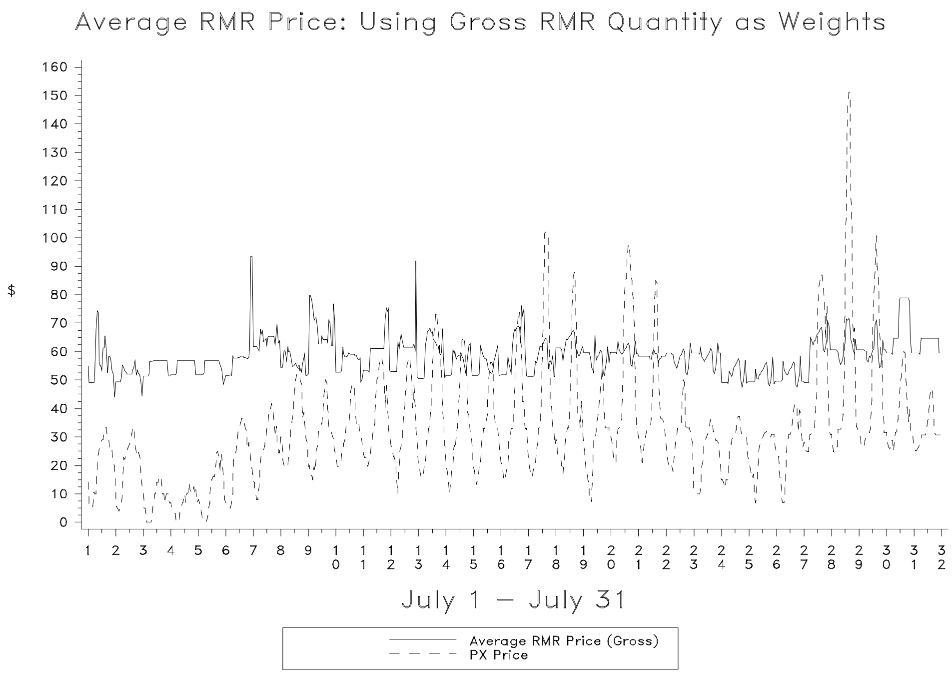

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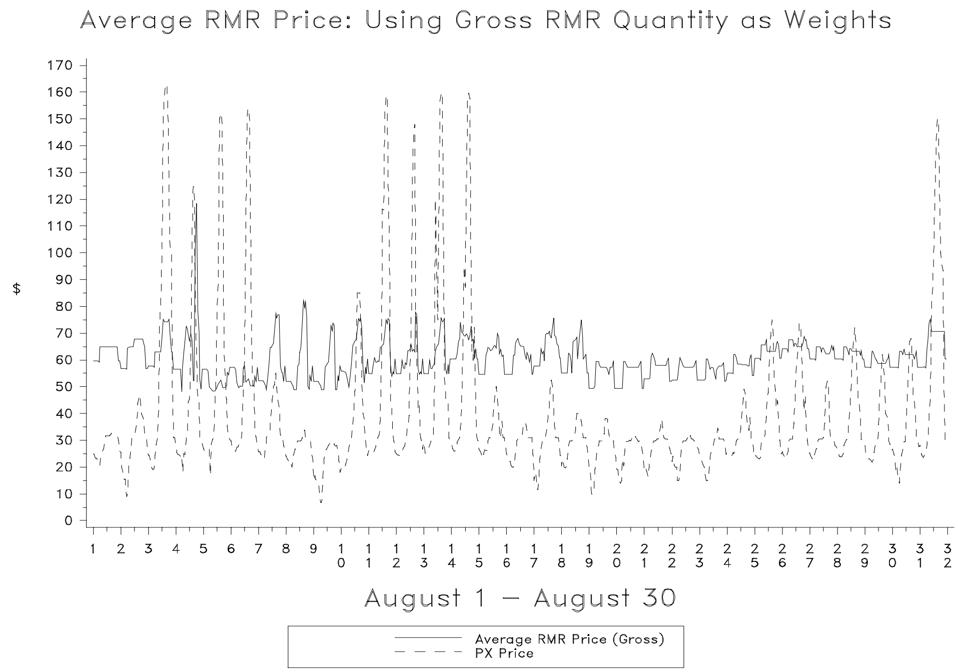


FIGURE 22

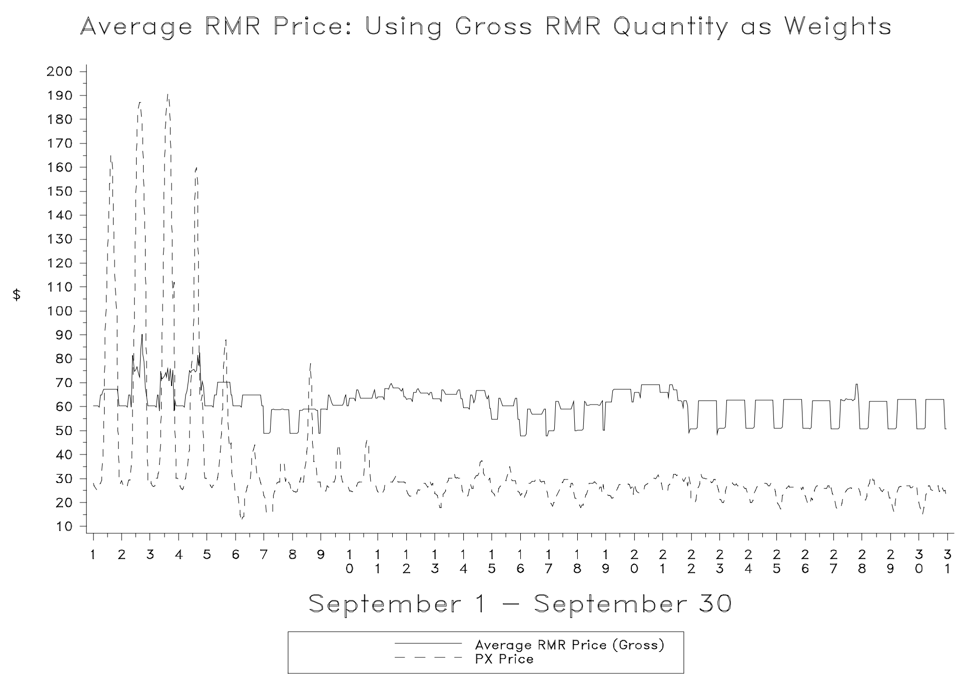


FIGURE 23

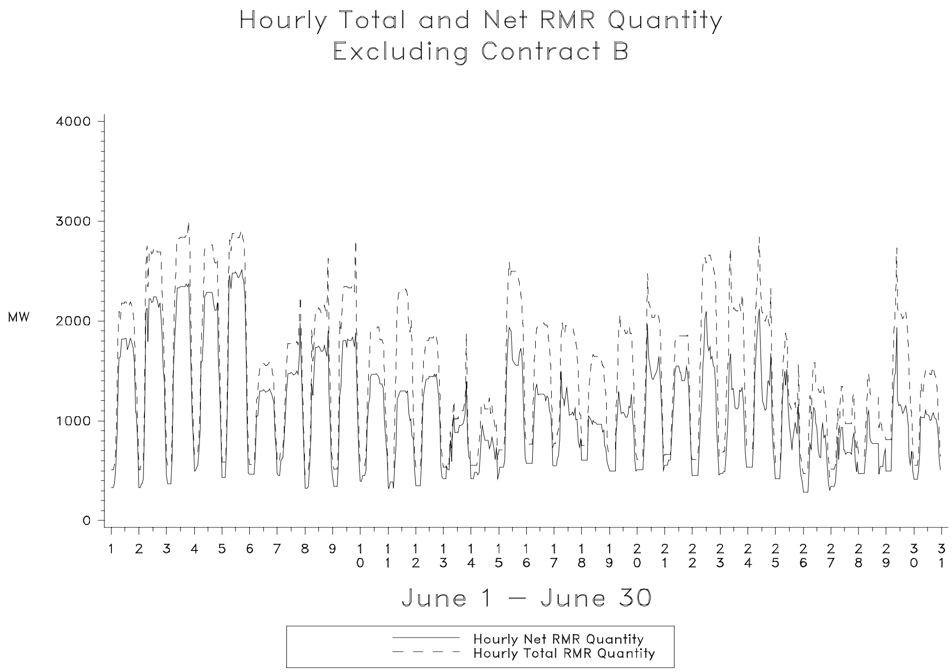
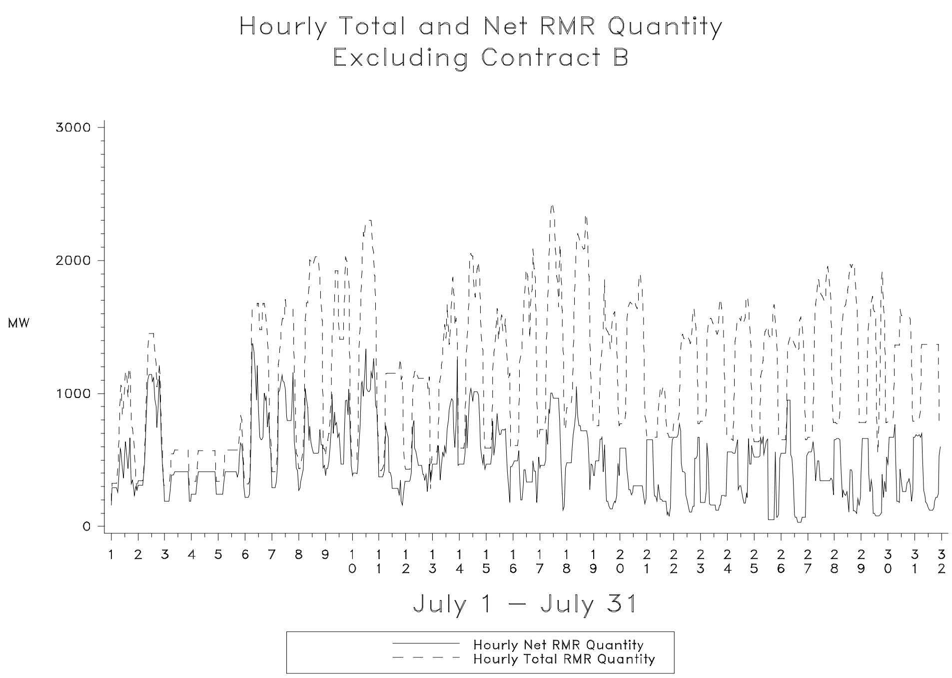


FIGURE 24



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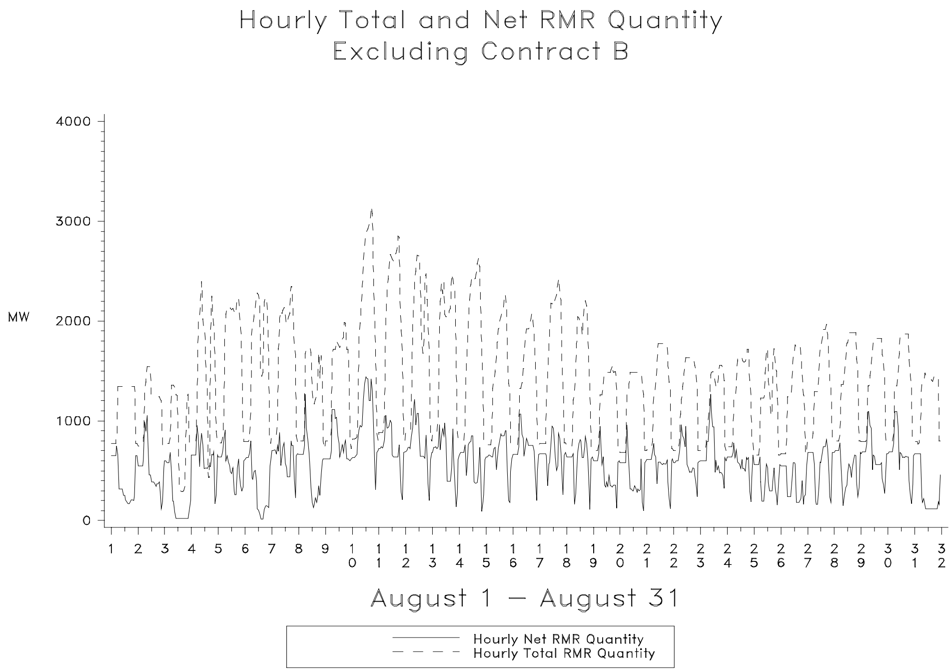

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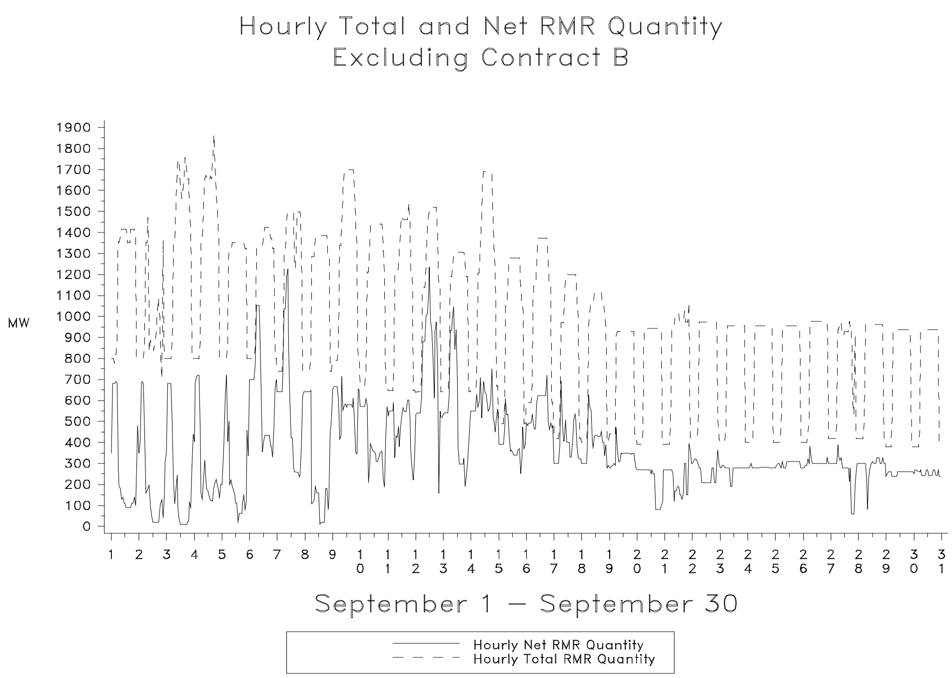
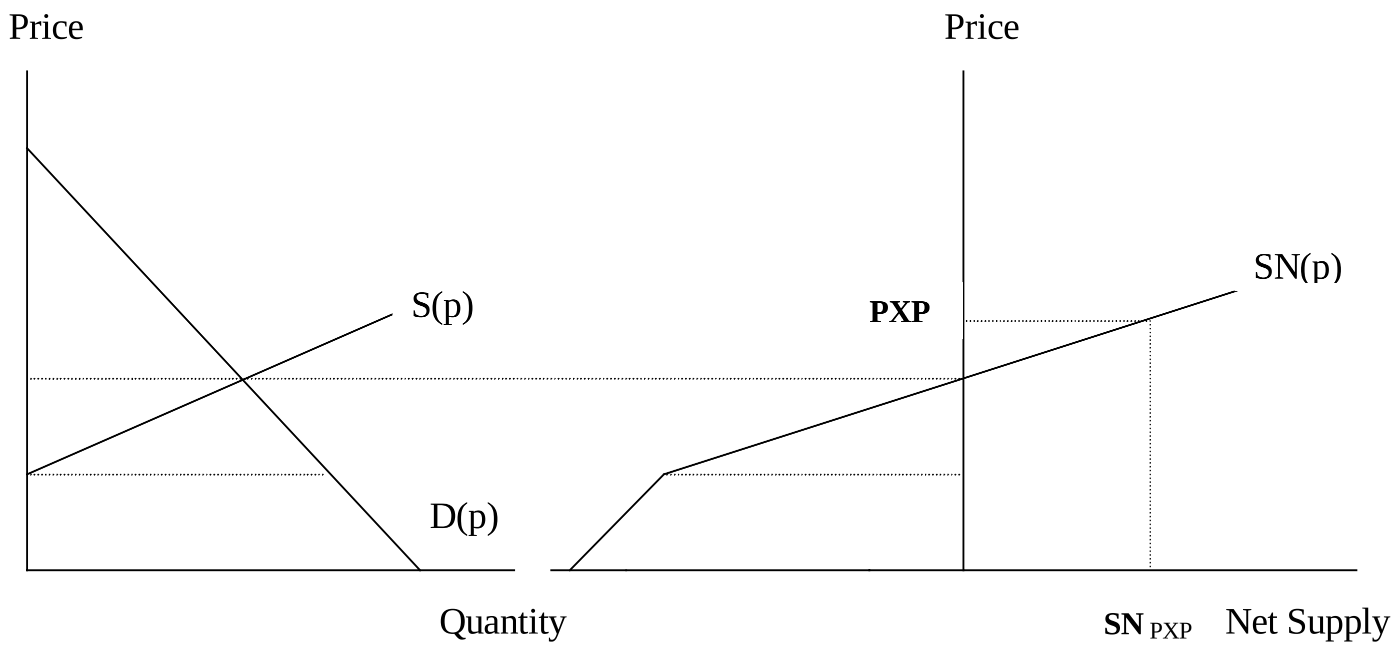


FIGURE 27:



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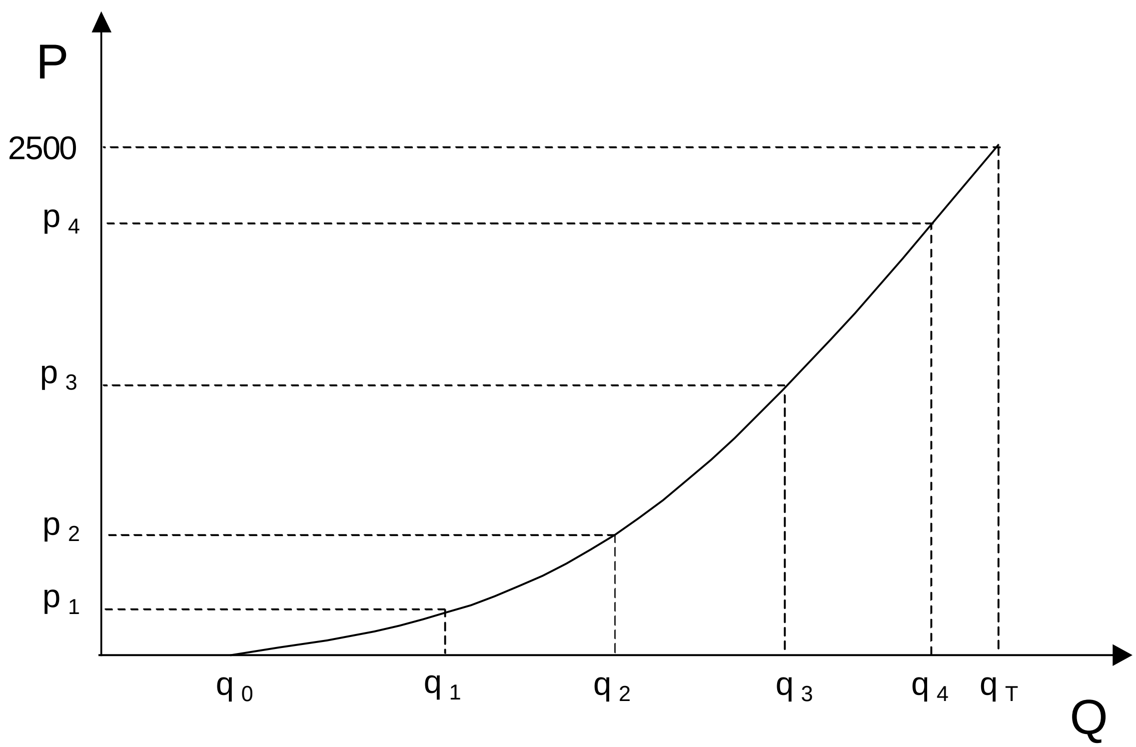

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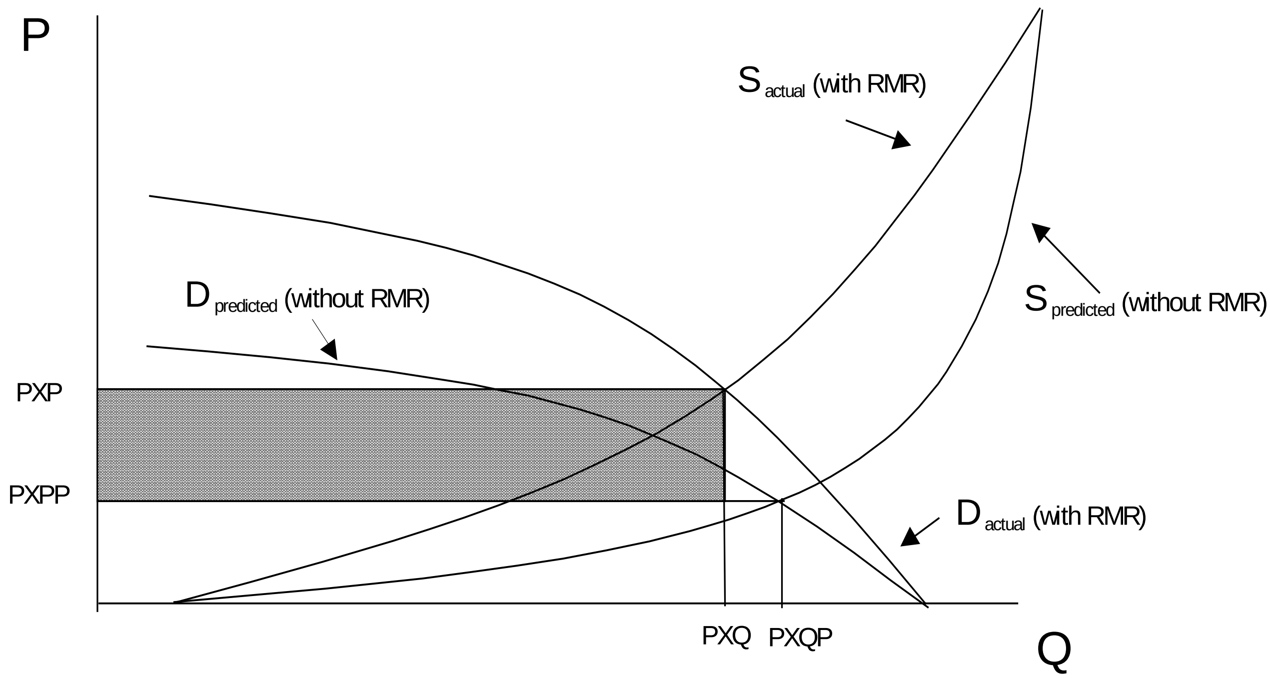

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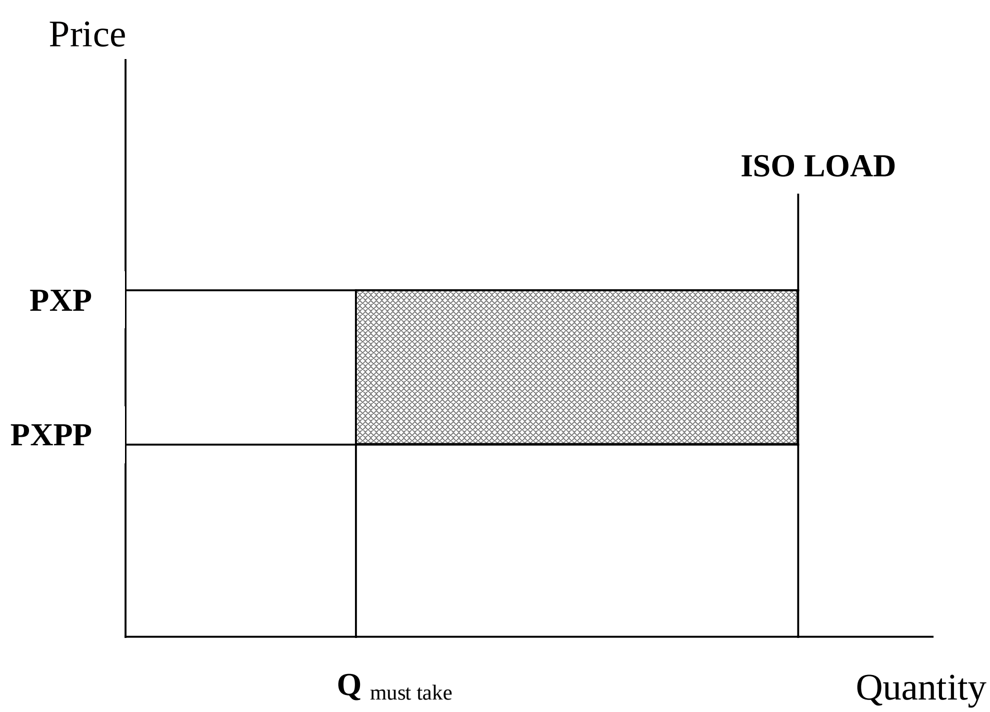

FIGURE 31: