ATTACHMENT A

TREATING RMR GENERATION AS MUST-RUN IN THE DAY-AHEAD MARKET

This attachment addresses issues related to pre-dispatch of RMR generation and how RMR generation should be accommodated into the competitive energy market. The attachment specifically focuses on key questions and concerns that have been raised by FERC staff, RMR unit owners, and other participants in RMR proceedings.

As an initial matter, it bears noting that RMR contracts are, in effect, call contracts under which the California consumers (through the ISO and transmission owner or "TO") pay all or a portion of the fixed costs of certain units, and, in return, are entitled to energy at variable cost from such units ("RMR units") for two limited purposes: to ensure local transmission stability, and to provide additional Ancillary Services (AS) capacity and energy when the supply of AS offered through the market is insufficient to meet quantities required to ensure system reliability. Although the ISO is the purchaser of these RMR services, it purchases these services on behalf of the TO and its customers. Thus, when an RMR unit is dispatched for RMR it has made a sale at a pre-determined price, and the TO (through the ISO) has made a purchase. This fact is reflected in the market crediting rules that credit market revenues from energy provided under RMR contract calls to the ISO and, ultimately, the TO. This perspective is important as it helps focus on the fact that any rules about how the RMR energy is accommodated into the ISO schedules are in reality rules on how RMR generation that has *already been purchased by TO's* is *used*, not on how any other generation resources of RMR owners is *sold* in the market. Thus, any rules for how RMR generation should be accommodated into the market should treat RMR energy in the same manner that any rational purchaser would utilize energy they had already pre-purchased to adjust how much energy they would purchase in subsequent spot markets.

This perspective — that RMR energy has been pre-purchased by the TO's — leads to the conclusion that once RMR energy is dispatched, the TO should decrease how much energy they purchase in subsequent spot markets based on the fact that they had already pre-purchased by "calling" upon RMR. One approach would be for the TO to reduce the amount of demand it schedules in the PX once the RMR energy is predispatched by the ISO. In effect, the TO (through the ISO) has a bilateral contract for the energy that operates outside of the PX Day-Ahead market. The ISO is obligated to pay the strike price (variable cost) when the energy is called. At that point, the energy called under the RMR contract has, in effect, already been purchased by the TO. An alternative is for the RMR owner to schedule the RMR energy into the PX as a "price taker" – essentially making it equivalent to other regulatory must-take energy such as QF purchases and nuclear energy. Either alternative produces the same result.

This paper discusses the polar views of the RMR owners and those in the buyer group on market rules related to pre-dispatch of RMR generation and how RMR generation should be accommodated into the competitive energy market.

1. How would bidding RMR as must-run versus at variable cost affect the market clearing price in the Day Ahead PX market? Which approach results in the "correct" price signal?

Owners of RMR units contend that treating RMR as must-run in the PX Day-Ahead Market artificially reduces the market clearing price (MCP), and sends an improper price signal to market participants. For sake of discussion, Figures 1 and 2 replicate a specific example which has been presented by RMR unit owners to illustrate this point. As shown in Figure 1, this example assumes by bidding RMR at variable cost, the market would clear at a price of $30. As shown in Figure 2, the market would clear at a price of $25 if RMR were bid in the Day-Ahead Market at a zero price.

Bidding RMR generation at variable cost in the hours and amounts subject to an RMR energy dispatch ignores the fact that this generation must run and ultimately will be used to meet demand. As shown in Figure 2, this results in excess supply being purchased in the Day-Ahead Market. Purchasing this excess supply increases the PX price. In other words, the MCP would be lower if demand in the Day-Ahead Market was not artificially inflated by the inclusion of demand that must ultimately be met by RMR generation. This requires that consumers pay twice for the local reliability provided by RMR units: once through direct fixed cost payments to generators, and again through higher PX prices. Under current ISO protocols, this excess supply "spills over" into the real time imbalance market, where supplier D (whose $30 bid set the MCP) may be decremented to balance supply and demand in real time.

Since the resulting MCP of $30 does not reflect the actual bid price of the marginal suppler ($25), an inefficient price signal is sent to potential buyers and suppliers.

- From the perspective of buyers, the $30 MCP discourages potential additional demand that may exist from entering the market at prices between the observed MCP of $30 and the $25 bid price of the marginal non-RMR supply actually needed to meet existing demand.

- From the perspective of suppliers, the $30 MCP provides an incentive for additional excess supply at this price range to enter the market, even though the bid price of the marginal non-RMR supply actually needed to meet demand is only $25.

Figure 3 illustrates how correct price signals can be sent to both suppliers and buyers by "netting out" the 500 MW of demand that must be met by RMR generation from the demand that must be met through the broader market. When the 500 MW of demand that must be met by RMR generation is subtracted from overall demand, the MCP of $25 reflects the actual cost (or bid) of the marginal supplier. No incentive is provided for additional suppliers to enter the broader market with bids between $25 to $30. Figure 4 illustrates how the same outcome can result from treating RMR as must-run generation through zero priced bids in the PX. This has exactly the same effect as "netting out" the amount of demand that must be met by the RMR unit from the overall market, but accomplishes this within the existing market structure more efficiently and with the least potential disruption.

Figure 1
Bidding RMR variable cost ignores that reality that RMR must be used to meet a portion of actual demand

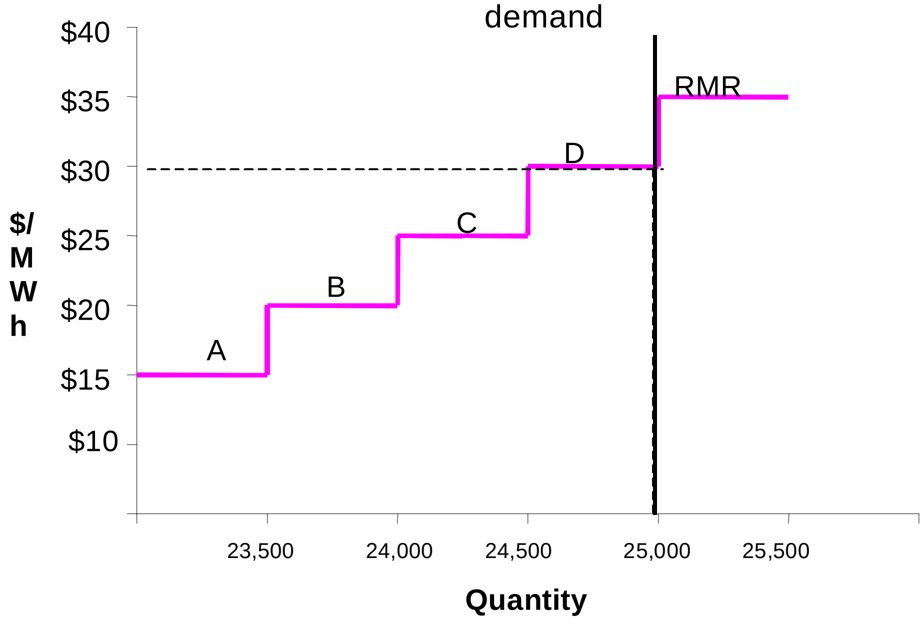


Figure 2
Bidding RMR at variable cost creates excess supply and sets MCP based on cost of excess supply that is not needed to meet demand

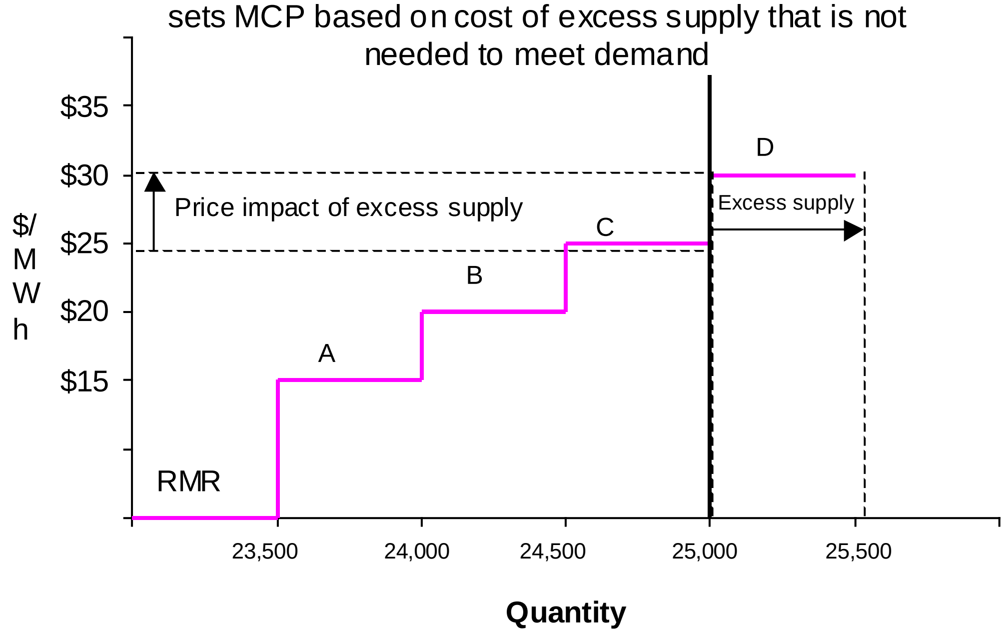


Figure 3
With RMR generation netted out of Day Ahead demand, MCP equals the bid price of the marginal supplier needed to meet demand

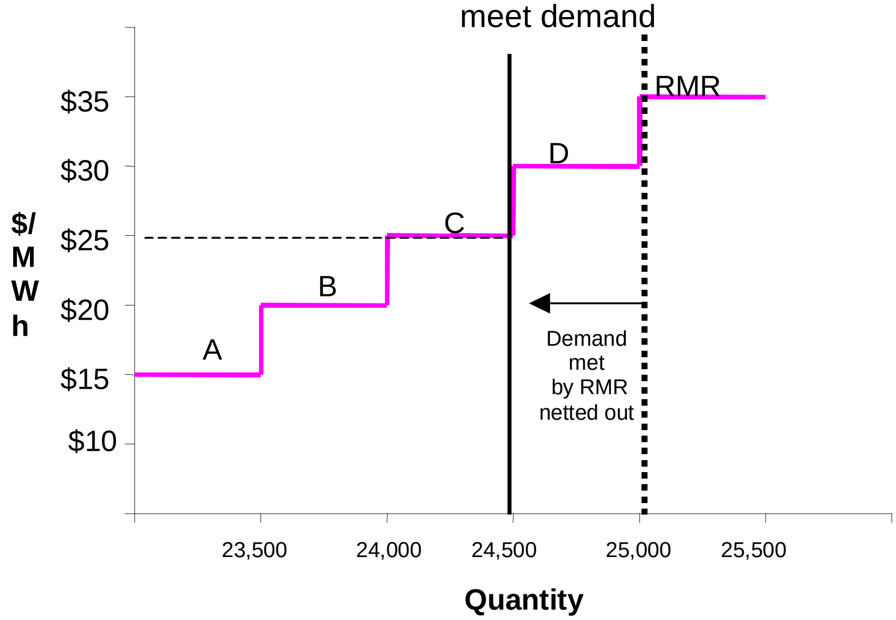
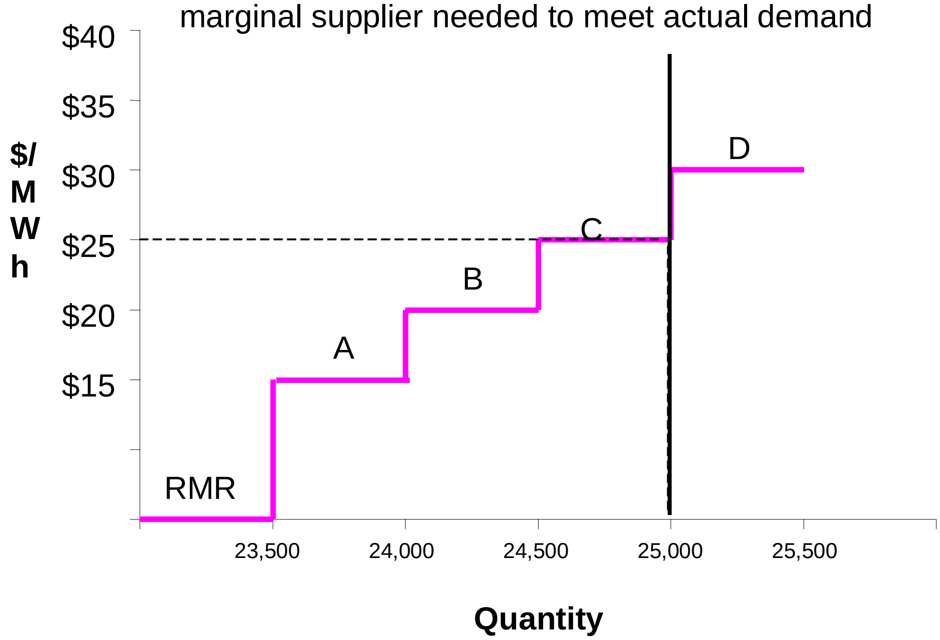


Figure 4
Bidding RMR as must-run in the Day-Ahead PX nets out RMR supply from demand, and results in MCP equal to bid price of marginal supplier needed to meet actual demand



2. What is the proper baseline, or starting frame of reference, for assessing whether bidding RMR generation as must-run in the Day-Ahead Market *distorts* or *corrects* the market clearing price?

The issue of whether treating RMR generation as must-run in the PX *distorts* or *corrects* the market price resulting from current ISO protocols depends on the baseline, or starting frame of reference, used to assess this impact. Compared to 1998 operating protocols, for instance, bidding RMR as must-take may result in a *lower* PX price during many hours. However, as depicted in Figure 2, not treating RMR as must-run in the Day-Ahead Market results in a price that is *higher* than would result if RMR generation that has been pre-purchased by TOs is netted out from their demand, as depicted in Figures 3 and 4. Thus, the issue of whether this *increases* or *decreases* the PX prices depends entirely on the baseline used to assess the impact.

From the perspective of both economic efficiency and equity, we believe that treating all RMR generation as must-take provides the proper baseline. As illustrated by the example provided in Question 1, treating RMR as must-run in the PX results in more efficient price signals than current protocols, or any proposals for bidding RMR into the PX at variable cost. Netting RMR out of demand in the Day-Ahead Market mitigates the potential market inefficiencies and price volatility that are associated with the supply/demand uncertainty. Netting out RMR from the PX market also results in a more equitable outcome, by preventing buyers from "paying twice" for local reliability: first, through fixed cost payments and reimbursement for the full variable operating costs of "non-economic" RMR, and, again through higher overall market prices.

Finally, when assessing what the "proper" baseline is for the PX market, it is important to note that the original design of California's energy markets called for RMR requirements to be treated as must run resources. For instance, studies of the state's electricity markets commissioned by state policymakers to address potential impacts of restructuring were based on the explicit assumption that "all bilateral contracts such as QFs, must-run units, must-take contracts and other regulatory resources are dispatched without any consideration of their costs and cannot set the market clearing price". [1]

Market protocols provided to market participants in the months prior to market start-up clearly outlined a market design in which the ISO, in accordance with its Scheduling Protocol, would provide schedules for RMR generation prior to the submission of bids for the Day-Ahead Market. [2] Protocols for managing overgeneration during periods "when participants' demand is less than the sum of regulatory must-take, regulatory must-run, and reliability must-run," provide that overgeneration be resolved by reducing schedules of regular market schedules first, followed by regulatory must-take units. Schedules for reliability must-run units were explicitly excluded from curtailment due to overgeneration.[3]

Shortly prior to market open, this market design was modified so that RMR energy requirements would be specified only after close of the DA market, in order to maximize the portion of RMR requirements that could be met through the PX DA market. However, operating experience indicates that this approach has resulted in significant distortions of the PX market, and that the ISO's "market first" principles can best be met by treating RMR requirements as must-take in the PX market.

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[1] *Modeling Competitive Energy Markets in California: Analysis of Restructuring*, prepared for the California Energy Commission by LCG Consulting, October 11, 1996, p.3-6

[2] *California's New Electricity Market, Seminar 2: Trading and Scheduling at the PX,* California Power Exchange, October 17, 1997, p.43

[3] Ibid, p.55.

3. If treating RMR as must-run results in a lower PX price, does this give the transmission owners and ISO an incentive to continue or even increase reliance on RMR, rather than other options for addressing local reliability problems?

First, it is important to note that any decrease in the PX costs relative to a "no-RMR" scenario that results from netting out RMR generation from the rest of the market would be offset by the total direct costs of RMR, which include fixed cost payments and reimbursement to generators for variable operating costs that exceed market prices.

More importantly, on a day-to-day basis, RMR dispatch notices are the product of standard protocols and system reliability requirements. The amount of RMR called each operating day represents the minimum level required to meet minimum reliability requirements. The rules are clear -- direct financial costs or indirect market impacts are not to be factored into these decisions by ISO operating staff in any way except when there are *two or more RMR options* to meet the reliability need, in which case, the least cost option is to be chosen.

With respect to longer term planning, the ISO Board has already commenced an aggressive plan to pursue alternatives to current RMR units through the Local Area Reliability Service ("LARS") process. In fact, one of the key reasons for proposed modifications to the current RMR contracts to make remuneration through an up front fixed option payment is to provide a clearer, stronger financial signal that can be used to attract and evaluate competitive alternatives to existing RMR units.

4. Does the proposed RMR interim relief provide proper locational price signals for new options for meeting local reliability requirements ?

Yes. The fixed cost payment is designed so that it may be used to attract and evaluate all options for meeting local reliability criteria, including both transmission, distributed generation, and demand side options.

In addition, as demonstrated in response to Question 1, treating RMR as must run generation resources results in a proper price signal for the broader market and the actual (potentially lower) cost of the marginal non-RMR supplier. In combination with fixed cost payments for RMR units, the price signals sent by treating RMR as must-run resources serve to provide more efficient market incentives for investment in the "right" type of new supply, transmission, and demand options.

5. How much more frequently will the PX market clear at zero if RMR generation is treated as must-run in the PX? What will be the impact on price during other hours?

RMR unit owners have expressed concern that treating RMR as must-run in the Day-Ahead Market will cause the PX market to clear at zero much more frequently.

The PX market clears at zero only when the sum of nuclear units, QFs, other regulatory must-run, and other capacity bid in through the market at zero exceeds the quantity of demand. During the 143 hours when the PX price cleared at zero during 1998, ISO records indicate that the amount of additional capacity from RMR units through *schedule changes* averaged less than 3.5% of the total amount purchased in the PX (581 MW of RMR, compared to an average PX MCQ of 16,773 MW). Thus, relative to actual 1998 market outcomes, we would expect a relatively small increase in the number of hours that the PX clears at zero if all RMR had been treated as must-run.

More importantly, however, the fact that this additional amount of RMR represents such a small percentage of the total amount of capacity bid in at zero (< 3.5%) illustrates that zero prices in the PX can only be caused by zero priced bids from these other generation sources, which include non-must run units. Without zero priced bids from the non-RMR resources, the PX would not clear at zero in any hour. As previously noted, original market protocols of the PX market explicitly required that overgeneration be resolved by reducing schedules of regular market schedules first, followed by regulatory must-take units, with schedules for reliability must-run units being explicitly excluded from curtailment due to overgeneration.[4] Thus, we believe that when this issue is viewed from the proper baseline – with demand that must be met by RMR resources netted out of the PX market – RMR by itself could never *cause* the PX market to clear at zero.

RMR unit owners contend that if treating RMR as must-run lowers prices in some hours, prices may need to be higher in other hours, particularly during peak periods. This illustrates the key point that treating RMR as must-take generation does not limit in any way what suppliers may bid for the non-RMR portion of their supply portfolio. Proposed bidding rules for RMR units do not require that generators simply "shift" their supply curves by adding an additional segment of capacity (priced at zero) that is equal to their RMR contract requirement. Thus, if simply shifting the supply curve in this manner would result in profits that are insufficient to cover fixed costs of current capacity and new supply required meet demand growth, market clearing prices could be expected to rise as suppliers increased bid prices for supply bids within the range of the supply curve at which market clearing prices are set.

To the extent that any increase in the numbers of hours the PX clears to zero requires that suppliers bid higher prices in the peak hours, improved price signals would be sent to buyers which reflect the difference in cost of supplying off-peak versus peak power. Any such increase in the price differential between peak and off-peak hours would help stimulate economically efficient investments in demand side options by making these more cost-effective from the perspective of end-users and the state's IOUs.

[4] Ibid, p.55.

6. Will treating RMR as must-run generation in the PX increase or decrease price volatility?

RMR unit owners contend that peak prices – as well as overall price volatility – will increase if RMR generation is treated as must-run in the Day-Ahead Market.

The ISO's current practice is to issue schedule changes after the Day Ahead energy schedules of each generating unit are finalized. If sufficient demand exists in the real time market, this excess supply is used to offset demand in real time. Otherwise, other supply units are decremented to "make room" for RMR in the real time market.

This creates a significant, unnecessary source of both supply and demand uncertainty, which is likely to decrease overall market efficiency and increase price volatility during peak periods. Individual buyers, for instance, may seek to take advantage of the extra supply of RMR that appears after close of the Day-Ahead Market by shifting a portion of demand from the PX to the ISO's real time imbalance market. However, due to lack of perfect information about the actions of other buyers and the actual amount of RMR appearing in real time, overall demand shifted to real time will often significantly exceed or fall short of extra supply available from RMR. Uncertainty about the balance between the amount of RMR supply and demand shifting to real time in anticipation of this supply creates greater price volatility in both the real time and Day-Ahead Markets.

Proposals which would require that RMR generation which is not scheduled in the Day-Ahead Market to be bid at zero in the Hour Ahead may create similar market uncertainties and inefficiencies. Such an approach would provide buyers with an incentive to try to take advantage of this supply by placing a portion of demand in the Hour Ahead market. However, due to imperfect information about the amount of RMR supply (as well as the amount of demand from other buyers that would appear in the Hour Ahead Market in anticipation of this supply), significant imbalances of supply and demand would likely occur in the Hour Ahead market during many hours, with excess supply or demand spilling over into the real time imbalance market.

Given that RMR requirements are already determined by the ISO prior to the Day-Ahead Market, pre-dispatching RMR units and treating this capacity as must-run in the Day-Ahead Market based on this information represents a very simple way to provide perfect market information regarding the actual impact of RMR on market demand and available supply. Market efficiency is likely to be increased by allowing this information to be incorporated into decisions regarding the commitment and management of both demand and non-RMR supply resources.

7. What are the potential impacts of bidding RMR generation at variable cost? How could bidding at variable operating costs increase PX costs?

Under the *contract path* it is proposed that RMR unit owners will be compensated based on the difference between their variable operating costs and the market price of energy. If RMR requirements are pre-dispatched, RMR unit owners will logically select the contract path for all time periods when PX prices are expected to be *lower* than the RMR unit's variable operating cost. Thus, if RMR generation selecting this new contract path is bid into the PX at variable cost – as proposed by RMR unit owners --- the bulk of RMR generation under this path will not clear the PX market.

However, as illustrated by the example presented in Table 1, pre-dispatch of RMR requirements – combined with the requirement that RMR generation under the contract path be bid into the PX at variable cost --- is likely to actually *increase* the PX price to some degree. This somewhat counterintuitive impact stems from the fact that generation is often scheduled through the PX market even when variable costs exceed the MCP through the Day Ahead. During these hours, units are often kept on-line due to longer term financial and operational factors such as start-up costs, start-times and minimum run times. Analysis of historical operating data supports the theoretical example presented in Table 1, in that both RMR and non-RMR units are often scheduled in the Day-Ahead Market even when their variable operating costs exceed market prices.

8. What is effect of different pre-dispatch and bidding options on direct payments between TOs and RMR unit owners?

Pre-dispatching RMR requirements, and allowing RMR unit owners to select either a *market path* or a *contract path* on an hour-by-hour basis is likely to result in an increase in payments by TOs under the contract path to reimburse generators for the difference between their variable operating costs and the market price of energy. This is illustrated by the example presented in Table 1, which shows how if given perfect certainty (or even a high probability) that a unit will be called under RMR, the operator's revenues are maximized by not scheduling any energy in the Day-Ahead Market during hours when the PX MCP is anticipated to be less than the unit's variable cost payment under its RMR contract. As discussed in the text accompanying Table 1, this is also likely to result in a decrease in the supply of generation bid into the Day Ahead PX market.

Table 1
Will Condition 1 of the New RMR Contract Eliminate the Impact of RMR Contracts on the Day Ahead PX Market?

The following example illustrates how the Day Ahead PX market may still be impacted by Condition 1 of the interim settlement. Without an RMR contract, the unit in this example would be likely to have its minimum operating capacity scheduled through the Day-Ahead Market even during hours when the PX price was lower than the unit's variable operating costs. Due to start-up costs and minimum run times of most RMR thermal units, overall revenues would be maximized by ramping units down to their minimal operating level and being a price taker in the Day-Ahead Market during these hours. In this example, if the unit's 20 MW RMR requirement can be predicted with a high level of certainty, operating revenues are maximized by not scheduling any energy in the Day-Ahead Market during hours when the PX MCP is lower than the unit's variable operating costs. This enables the RMR unit owner to get reimbursed for full operating costs, rather than the lower market energy price during these hours. In this example, being able to select this contract option increases net daily revenues from $3,040 to $5,000, but decreases the amount of RMR capacity that would be scheduled to meet demand in the PX market. The situation illustrated in this example can be avoided by pre-dispatching RMR requirements and treating this generation as must-run in the Day-Ahead Market. The example is presented graphically in Figures 6 through 7.

			Without RMR		With Condition 1 of Interim Settlement		
Hour	Unit VC	PX	PX Energy (MW)	Net Daily Revenue	PX Energy (MW)	Net Daily Revenue	Decrease in MW Bid < MCP
1	$40	$32	20	-$160			20
2	$40	$30	20	-$200			20
3	$40	$28	20	-$240			20
4	$40	$26	20	-$280			20
5	$40	$28	20	-$240			20
6	$40	$30	20	-$200			20
7	$40	$32	20	-$160			20
8	$40	$34	20	-$120			20
9	$40	$36	20	-$80			20
10	$40	$38	20	-$40			20
11	$40	$40	20	$0			20
12	$40	$42	100	$200	100	$200	
13	$40	$44	100	$400	100	$400	
14	$40	$46	100	$600	100	$600	
15	$40	$48	100	$800	100	$800	
16	$40	$50	100	$1,000	100	$1,000	
17	$40	$48	100	$800	100	$800	
18	$40	$46	100	$600	100	$600	
19	$40	$44	100	$400	100	$400	
20	$40	$42	100	$200	100	$200	
21	$40	$40	20	$0			20
22	$40	$38	20	-$40			20
23	$40	$36	20	-$80			20
24	$40	$34	20	-$120			20
				$3,040		$5,000	

Unit Capacity	= 100 MW	Minimum Operating Level	= 20 MW
Variable Operating Cost	= $40/MW	Minimum Operating Time	= 24 hours
RMR Requirement	= 20 MW		

Figure 6
Economic Operating Level (Without RMR Contract Option)

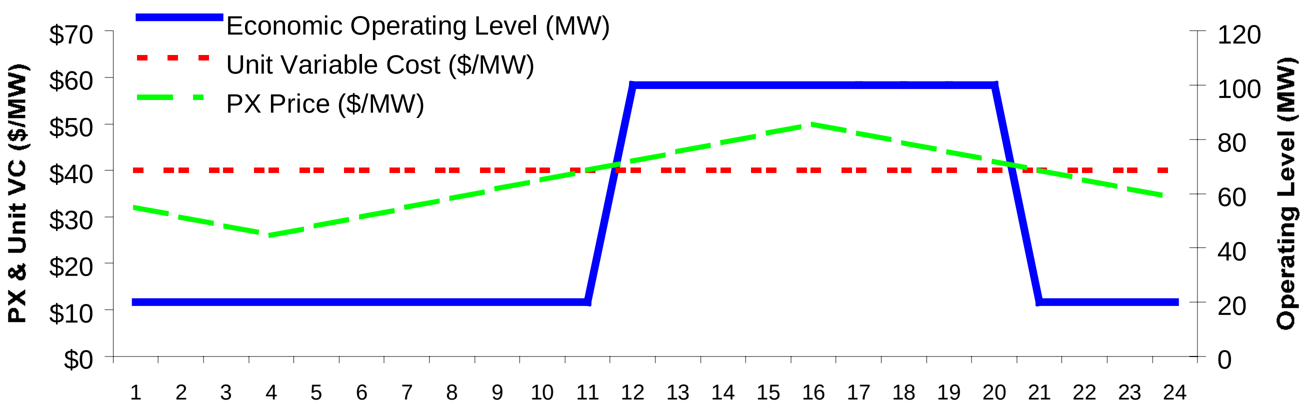

Figure 7
Net Operating Revenues (Without RMR Contract Option)

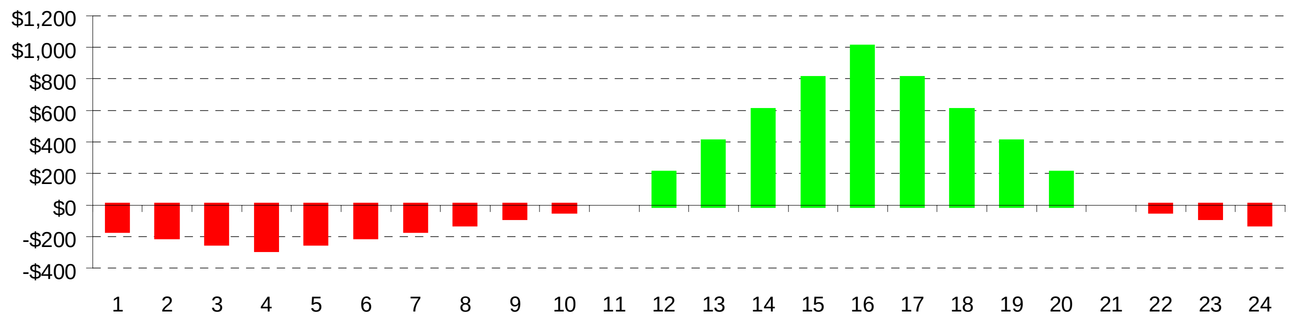

Figure 8
Net Daily Operating Revenue with RMR Contract