IDENTIFYING THE EXERCISE OF MARKET POWER IN CALIFORNIA

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EXECUTIVE SUMMARY

The unexpected and suddenly high prices in the California electricity market, beginning in June 2000, precipitated a variety of responses with far-reaching consequences. One central issue requires identifying and analyzing the scope and significance of any exercise of market power. A complete analysis of this issue would be important, but has not been done. The nature of the California market and the highly stressed conditions of that period present significant complications in separating the exercise of market power from other activities that would have substantially different policy implications.

A full analysis of the exercise of market power would require use of data available to the California system operator but not available in the public domain. These data have not been disclosed, nor apparently used in any study of the California market. However, the importance of the matter has prompted use of the publicly available data to attempt to assess the relative importance of market power in the California crisis. Employing simulation models to estimate prices and other approaches to identify economic and physical withholding, a series of studies have been offered in support of a conclusion that there was substantial market power exercised in California.

By contrast, another series of sensitivity analyses have concluded that the simplifying assumptions of the simulation models and the other analyses with publicly available data were enough to introduce errors as large as the effect that was to be estimated. In other words, the publicly available data were not up to the task of detecting a substantial exercise of market power.

The present paper stands in this series of analyses with conflicting conclusions. Here we go further into the sensitivity analyses in response to previous comments and critiques. The principal purpose is to clarify and bolster the analysis of what is at issue and why the impacts of the simplifications are not on their face either negligible or irrelevant.

Our further sensitivity analyses reinforce the conclusion that we cannot demonstrate the existence or the absence of an exercise of market power. However, there is no ambiguity in the conclusion that there are other features of the California market design that are fundamentally flawed and need to be corrected as part of the unique situation in California and the larger discussion of the implementation of Regional Transmission Organizations. These market reforms would be important no matter what the resolution of the analysis of the exercise of market power.

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I. INTRODUCTION

The tumult of the California electricity market and high prices beginning in June of 2000 raised the specter of an exercise of market power. A complete analysis of this issue would be important, but has not been done. Given the importance of the issues, however, even incomplete data have been applied and spawned debates about the size and scope of the exercise of market power. A recent paper of ours discusses further some of the theoretical issues and explains why we conclude that this is an empirical question.[2] Ideally, we would wait until all the data were available to address the empirical matters, but the importance of the issue and the pace of events preclude this more deliberate approach. Here we continue the discussion of the empirical matters, carrying further the sensitivity analyses and using some additional information obtained from the Mirant Corporation, which sponsored this work. The conclusion remains that:

> "With the available data in the public domain, and the special complications introduced by the California market design, the margin of error in estimating the extent of the possible exercise of market power through strategic withholding of electric generation is of the same order of magnitude as the effect being measured. On balance, to date the publicly available data provides no reason for the Federal Energy Regulatory Commission to change its conclusion that there is no evidence of strategic withholding nor any proof that no strategic withholding has occurred.

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[2] Scott M. Harvey and William W. Hogan, "Further Analysis of The Exercise Of Market Power In The California Electricity Market," November 21, 2001, hereafter Harvey-Hogan (November).

> By contrast, there is general agreement that the California electricity market design is 'seriously flawed.' Furthermore, there is evidence that the policy responses that have been adopted in California have accelerated an already serious market collapse. Hence, without dismissing the possibility of the exercise of market power, the principal policy focus should be on fashioning workable solutions for the other more serious problems in market design that relate to the underlying causes of the market meltdown."[3]

The proximate motivation of the present paper is to continue the discussion extended in the July 2001 Joskow and Kahn paper[4] commenting on our April 2001 paper,[5] which raises four empirical issues affecting the analysis of the exercise of market power in California. First, Joskow-Kahn argues that if minimum load costs are taken into account, the units that actually operated in California during high priced hours in June 2000 were not losing money.[6] As discussed further below, this is not the issue we raised. Rather, we asked whether the units that did not actually operate in California during high-priced hours in 2000 could have operated profitably at the simulated prices and further suggested that one cannot answer this question without taking account of start-up and minimum load costs. Moreover, the data consistently show that these costs are sufficiently large in magnitude to materially impact the answer to this question.

Second, Joskow-Kahn states that after modifying the simulation model to take account of the issues we raised in our April paper, they still find that their simulated price of electricity in California is materially less than real-world prices during June 2000.[7] They interpret this as evidence that could best be explained as an exercise of market power through withholding of capacity. The new simulation model, however, largely does not address the problems we pointed out in April and introduces new problems that predictably underestimate competitive prices. Simulation models that leave out important real supply constraints will predictably calculate prices that are lower than real-world prices, but such a difference does not provide a basis for conclusions regarding the existence or exercise of market power.

Third, Joskow-Kahn repeats the withholding analysis for somewhat different combinations of hours than in their earlier paper and again find an output gap.[8] The calculations largely ignore the observations we made in our April paper and the limitations remain. That is, the output gap includes the capacity of unavailable units, excludes deratings or environmental output limitations, uses capacities that may overstate the sustainable output of the units, and ignores whether units were coming on-line or would have been changing their output in response to

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3 Harvey-Hogan (April), p. ii.

4 Paul Joskow and Edward Kahn, "Identifying the Exercise of Market Power: Refining the Estimates," July 5, 2001 (hereafter referred to as Joskow-Kahn (July)).

5 Scott M. Harvey and William W. Hogan, "On the Exercise of Market Power Through Strategic Withholding in California," April 24, 2001 (hereafter Harvey-Hogan (April)).

6 Joskow-Kahn (July), pp. 5, 14-17.

7 Joskow-Kahn (July), p. 13.

8 Joskow-Kahn (July), pp. 19-20, 27.

sudden price changes. The magnitude by which these calculations overstate the actual output gap can be seen by analyzing the output gap calculated using the methodology during the hours of stage 1 and stage 2 emergency in which it is known that there was a shortage of capacity at any price.

Fourth, they state that they find clear evidence of physical withholding,[9] but Joskow-Kahn provides no supporting evidence.

II. START-UP AND MINIMUM LOAD COSTS

A. What Is the Question?

The example of Alamitos 2 on June 17, 2000 was used in Harvey-Hogan (April) to make an analytical point. In particular, neglect of start-up, minimum load costs and operating limitations could result in material errors in an estimation of profitability, especially important for marginal units. The choice of Alamitos 2 was made because of its characteristics and because on June 17 we had real data for operations over a wide range of plant output conditions. The data showed that ignoring these complicating factors would result in material errors in calculating the profitability of this marginal unit, to the extent of the possibility that it lost money from operating.

Joskow-Kahn argues that the particular results for Alamitos 2 were rare or unique. Joskow-Kahn's discussion of the Alamitos 2 example misses the point of the example and our paper, and does not address the discussion of an important limitation of the simulation analysis. Joskow-Kahn suggests that we have argued that our calculations of the profitability of Alamitos 2 on June 17, 2000 demonstrate that other units actually operating on high priced days during June 2000 operated unprofitably.[10] This was not what we said and not the point of the example. Indeed, such a claim would be irrelevant to the issues we have raised. We discussed the Alamitos 2 example in the context of the Joskow-Kahn simulation analysis.[11] Our point was and is that because the simulation methodology does not take account of start-up costs, minimum load costs, and unit inflexibilities such as minimum down times and up times, the simulation methodology does not replicate the choices that would determine the competitive level of electricity prices.

Tables 7, 8, and 9 in our April paper focused on the material difference between the apparent profitability of operating Alamitos 2 in an economic evaluation based on incremental heat rates and units that can turn on and off, hour to hour, and the real-world profitability of Alamitos 2. The difference was large. The point of this example was and is that simulations that dispatch generation to meet load and estimate prices based on incremental heat rates, in non-chronological models that do not consider start-up and minimum load costs or unit inflexibilities, will meet

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9 Joskow-Kahn (July), p. 23.

10 Joskow-Kahn (July), pp. 14.

11 Harvey-Hogan (April), pp. 25-33.

load with resources that could not always have operated profitably at those prices in the real system. As a result, the simulated prices may not measure the competitive level of energy prices.

Given the complexity of the market, it is not surprising to find an example of a plant actually operating and losing money even though prices were high in some hours. However, the Joskow-Kahn withholding conclusion does not depend only on showing that this event is rare or unique. The Joskow-Kahn conclusion requires showing that at even lower prices, the errors in calculating profitability would be negligible and that plants that were not operating would have been profitable. Furthermore, given the evidence of Alamitos 2 of the magnitude of the difference between profitability evaluated hour by hour based on incremental energy costs and profitability, when evaluated taking account of actual heat rates and the constraints of minimum load and start-up costs, it would be surprising to find that all of the plants that were not operating in the real-system but were dispatched based on incremental energy costs in the simulation could actually have operated profitably at much lower prices if we account for all of the costs.

It is not responsive to this observation and example to state that other units actually operating on June 17, or even all other units actually operating on every other high priced day, were profitable to operate based on real-world output, real world prices and actual operating patterns. The issue is whether the resources that were not used to meet load in the real world but were used to meet load in the simulation could actually have operated profitably at the simulated prices.

In using Alamitos 2 as an illustration of the importance of actual generator cost functions and inflexibilities, we had in mind a set of 13 generators included in the Joskow-Kahn simulation study that have relatively high heat rates for the minimum load block, as portrayed in Table 1. It can be seen based on the Klein and CEMS data reported in Table 1 that all of these units have relatively high minimum-load heat rates and some also have relatively high emissions rates. Six of these units, Alamitos 1 and 2, El Segundo 1 and 2 and Redondo Beach 5 and 6 (the “Sickly Six?”) also have relatively high NOx emissions rates. In aggregate, these 13 units account for roughly 2,929 MW of capacity, so whether they are on line and operating would have a material impact on supply and prices.

Table 1 Characteristics of High Cost Units						
			Full Load			
	Minimum Load Heat Rate (A)	Emissions Rate (B)	Incremental Heat Rate (C)	Average Heat Rate (D)	Minimum Load Block (E)	Klein Capacity (F)
Alamitos 1	28,899	0.123	10,056	10,663	10	175
Alamitos 2	28,899	0.189	10,056	10,663	10	175
Alamitos 3	25,283	0.076	9,338	9,898	20	320
Alamitos 4	25,283	0.060	9,338	9,898	20	320
El Segundo 1	27,838	0.125	9,901	10,591	10	175
El Segundo 2	27,838	0.136	9,901	10,591	10	175
El Segundo 3	24,628	0.061	9,201	9,741	20	335
Etiwanda 1	24,848	0.081	10,724	11,072	10	132
Etiwanda 2	24,848	0.089	10,724	11,072	10	132
Etiwanda 3	22,980	0.047	9,292	9,731	20	320
Etiwanda 4	22,980	0.049	9,292	9,731	20	320
Redondo Beach 5	31,617	0.168	9,532	10,530	10	175
Redondo Beach 6	31,617	0.094	9,532	10,530	10	175

Sources:

Cols. A, C, D, E, F – Joel Klein, “The Use of Heat Rates in Production Cost Modeling and Market Modeling,” April 17, 1998 (hereafter Klein (April 1998)).

Col. B emissions 2Q, 2000 CEMS.

Asking whether there were many units that were actually operating in the real world on high priced days that would have lost money at actual PX day-ahead prices has little bearing on the issue we raised. One question that would be relevant would be to ask whether any of the units that were not operating in the real world, but were dispatched to operate in particular hours in the Joskow-Kahn simulation, would have been profitable or unprofitable to operate in those hours at real-world prices taking into account real-world minimum load costs and operating inflexibilities. A second question to ask would be whether the units that actually were operating in the real world, would have been able to operate profitably at the prices simulated by Joskow and Kahn. Joskow and Kahn did not address either question in their reply. Instead, they suggest that the units that actually operated in the real world, operated profitably in the real world, evaluated at real-world prices. Whether this claim is correct or not, it is largely irrelevant to the issues we have raised regarding their simulation methodology.

B. Is Alamitos 2 on June 17 Unique?

In discussing our example of Alamitos 2 on June 17, Joskow-Kahn suggests that our statement that our "calculations for Alamitos 2 are only illustrative and we have not repeated this calculation for every unit for every day of June. The point of these calculations is that the financial impact of minimum load costs and operating inflexibilities is not necessarily insignificant"[12] was misleading. They suggest that this statement was misleading because:

> "readers may gain the impression that the Alamitos 2 example is typical of other units on other days and that "unprofitability" is an important explanation for the withholding behavior that we identified. However, Harvey & Hogan do not actually display similar calculations for any other units or days. We have now performed profitability calculations for every day listed in Table 5: the days which have the high-price hours that we focus on in our analysis of withholding behavior. This task was not unduly onerous, and Harvey-Hogan could have performed it had they wished. We find that there was only one unit on one day in June which was unprofitable under the Harvey-Hogan criteria using hourly CEMS data to account for minimum-load costs."[13]

The Joskow-Kahn comments are misdirected on several matters. First, the point of our analysis was not that the units that actually operated on high priced days in the real world were operating unprofitably in the real world. Our point was that ignoring minimum load costs and physical unit characteristics materially changes the apparent profitability of supplying output, and analyses that ignore these costs are estimating a supply curve that may be materially different from the real supply curve. Not only did our quoted statement explicitly refer to the financial impact of minimum load costs and operating inflexibilities, but it followed six pages discussing how the apparent profitability of supplying incremental output *changed* when minimum load costs and inflexibilities were taken into account.[14] It is even more surprising to miss the point of our comment since it appeared directly below Table 9 in the April paper, reproduced as Table 2 below with one adjustment.

The Alamitos 2 example shows the potential for mistaken conclusions regarding the profitability of increased output that arises when these added costs are ignored. The problem would be compounded if in place of the actual prices observed in the market the profitability analysis were done at the lower prices in the Joskow-Kahn simulation.

Table 9 in our first paper used the same set of "profitable hours" whether allowance costs were added or not. The calculations in Table 2 only include as profitable those hours that were profitable with allowance costs included. Tables 3 through 6 follow this convention. Table 9 does not merely report that the operation of Alamitos 2 would have been unprofitable under certain assumptions. Instead, it portrays a series of comparisons illustrating how substantially the apparent profitability of operation could change, when account was taken of minimum load costs

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12 Harvey-Hogan (April), p. 32.

13 Joskow-Kahn (July), p. 15.

14 Harvey-Hogan (April), pp. 25-32.

and operating inflexibilities. This difference is important in assessing whether units that were *not operating* in the real world could have operated profitably in the real world in the hours the Joskow-Kahn simulation dispatches them based on their incremental costs. Moreover, this difference is also important in assessing whether units that did operate in the real world could have operated profitably *at the prices simulated by Joskow and Kahn,* rather than at real-world prices. Joskow-Kahn addresses neither of these issues in the reply.

Table 2
Alamitos 2 Profitability June 17, 2000
With and Without Emissions Allowance Costs

	All Hours		**Profitable Hours**	
	No Allowance Costs	**Allowance Costs**	**No Allowance Costs**	**Allowance Costs**
Actual Heat Rate	(1,724)	(36,382)	22,119	7,981
Incremental Heat Rate	45,573	25,027	47,870	30,906

Notes:

Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.189 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.
CEMS data are not adjusted for Daylight Savings Time.

Source:

Harvey-Hogan (April), Table 9, p. 32.

Instead, Joskow-Kahn addresses the implications of not calculating the profitability at real prices of the units that were actually operating on 14 high priced days. Joskow and Kahn indicate that they have made a similar calculation for every unit on these 14 days (not every day in June) and have found that Alamitos 2 is unique.[15] In fact, however, they did not repeat our calculations to show the *change* in apparent profitability when start-up costs, minimum-load costs and unit inflexibilities are taken into account for even a single unit on a single day, let alone for every unit on many days. The calculations in Table 9 of our April paper, reproduced as Table 2 above, calculated the apparent profitability of Alamitos 2 operation under a variety of assumptions regarding heat rates, allowances and inflexibilities to show the large differences in apparent profitability of operating Alamitos 2 in the real world and in the Joskow-Kahn simulation.[16]

15 Joskow-Kahn (July), p. 15.

16 The calculations based on the actual heat rate also used the actual SP-15 day-ahead price, while the calculations using the incremental heat rate used the hypothetical PX unconstrained price to which Joskow and Kahn (March) compared their simulation results (p. 14).

There is no such calculation in the Joskow-Kahn paper.[17] To make the point, we do not need repeat these calculations for every unit on every day. We have repeated them for Alamitos 3 and 4 on June 17 and 23, days on which the calculations show that the operation of these units would have been profitable at real-world PX prices (see Tables 3 to 6 below). Our comparisons again show, however, that the apparent profitability of operating these units is materially affected if the calculation does not take account of actual heat rates, minimum load costs and operating inflexibilities. We have now undertaken these calculations for five unit days, which reinforces the point that the changes matter.

On June 17, the difference between the apparent profitability of operating Alamitos 3 and 4 based on incremental heat rates for the profitable hours of the day was approximately $100,000 higher than the profitability evaluated at actual heat rates over the day as a whole. This is an even larger error than in the case of Alamitos 2 on June 17.

The impact on prices could be important. For instance, a 200 MW plant operating with 5 high-priced hours over the day would need a price increase of $1/MW to make up each $1,000 of cost difference.[18] Hence, a price increase of $100/MW would be required during these high-priced hours to make up a $100,000 difference in profits. How this would play out in the complex California market is far from certain, but the error does not appear on its face to be negligible.

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[17] The comparisons in the April paper would be slightly affected by adjusting the CEMS data for Daylight Savings Time, discussed in Section IV below. The adjusted comparison is:

Table 2 (Adjusted CEMS Data)
Alamitos 2 Profitability June 17, 2000
With and Without Emissions Allowance Costs

	All Hours		Profitable Hours	
	No Allowance Costs	**Allowance Costs**	**No Allowance Costs**	**Allowance Costs**
Actual Heat Rate	(43)	(34,585)	22,902	8,752
Incremental Heat Rate	46,710	26,279	48,530	31,324

Notes:
Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.189 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.

[18] The numbers are illustrative for simplicity. The Alamitos 2 plant has a Klein capacity of 175 MW.

Table 3 Alamitos 3 Profitability June 17,2000 With and Without Emissions Allowance Costs				
	All Hours		Profitable Hours	
	No Allowance Costs	Allowance Costs	No Allowance Costs	Allowance Costs
Actual Heat Rate	118,186	79,746	145,828	119,543
Incremental Heat Rate	201,993	168,503	205,636	176,116

Notes:
Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.076 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.
CEMS data, adjusted for Daylight Savings Time.

Table 4 Alamitos 4 Profitability June 17,2000 With and Without Emissions Allowance Costs				
	All Hours		Profitable Hours	
	No Allowance Costs	Allowance Costs	No Allowance Costs	Allowance Costs
Actual Heat Rate	114,489	83,242	143,262	122,033
Incremental Heat Rate	204,425	177,448	207,835	183,695

Notes:
Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.060 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.
CEMS data, adjusted for Daylight Savings Time.

On June 23, the difference between the profitability of operating evaluated based on incremental heat rates in the profitable hours and based on actual heat rates over the day was lower, but still exceeded $40,000 for both of these units.

Table 5 Alamitos 3 Profitability June 23,2000 With and Without Emissions Allowance Costs				
	All Hours		**Profitable Hours**	
	No Allowance Costs	**Allowance Costs**	**No Allowance Costs**	**Allowance Costs**
Actual Heat Rate	328,036	286,047	343,258	309,615
Incremental Heat Rate	361,020	323,981	362,068	328,876

Notes:
Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.076 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.
CEMS data, adjusted for Daylight Savings Time.

Table 6 Alamitos 4 Profitability June 23, 2000 With and Without Emissions Allowance Costs				
	All Hours		**Profitable Hours**	
	No Allowance Costs	**Allowance Costs**	**No Allowance Costs**	**Allowance Costs**
Actual Heat Rate	320,302	287,111	337,129	310,529
Incremental Heat Rate	357,976	329,233	358,934	332,575

Notes:
Actual heat rate calculations use the SP-15 PX price.
Incremental heat rate calculations use the unconstrained PX price.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions Rate = 0.060 lb./mmBtu per CEMS.
Calculated profitability does not include variable O&M or station costs.
CEMS data, adjusted for Daylight Savings Time.

Hence, the example of Alamitos 2 on June 17 was not unique, for the point it was offered to illustrate.

C. Was Operation Profitable at Real-World Prices?

Second, Joskow and Kahn's comment is also mistaken in suggesting that the operation of all of these units would have been profitable at PX prices for their real-time output during these relatively high priced days, taking into account minimum load costs and average heat rates. In reality, the six high cost units (Alamitos 1, 2; El Segundo 1, 2; Redondo Beach 5 and 6) were operating on the days of June 17, 21 and 23 in only nine instances and their operation would have been unprofitable at PX prices and actual output in six of these instances, when emission allowance costs are taken into account (see Table 7 below, and Table 7 in Joskow-Kahn (July)).[19]

Table 7
High Heat Rate Unit Operating Profitability
Day-Ahead PX Prices and Real-Time Schedules

	June 16, 2000	June 17, 2000	June 21, 2000	June 23, 2000
Alamitos 1	--	--	(13,144)	(3,991)
Alamitos 2	146,884	(34,585)	(20,502)	15,615
Alamitos 3	1,427,307	79,746	65,164	286,047
Alamitos 4	1,401,572	83,242	72,084	287,111
El Segundo 1	224,362	--	--	--
El Segundo 2	239,846	--	19,904	(12,230)
El Segundo 3	113,506	27,937	--	169,447
Etiwanda 1	358,102	--	--	--
Etiwanda 2	301,613	--	--	--
Etiwanda 3	1,021,846	66,865	(998)	260,470
Etiwanda 4	902,691	51,400	(315)	270,656
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(18,235)	4,921

Notes:
CEMS heat rates.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions rates per CEMS.
Price = SP-15 PX price.
Calculated profitability does not include variable O&M or station costs.
CEMS data, adjusted for Daylight Savings Time.

[19] See Joskow-Kahn (July) Table 7, p. 17.

Joskow and Kahn reach the conclusion that the operation of several of these units would have been profitable in the real world by apparently either omitting emissions costs[20] or adding to profits their assessment of ancillary service revenues. Emission costs were included in our earlier analysis and as seen in Table 7 (as well as Table 7 in the Joskow-Kahn reply), the operation of several additional units was unprofitable applying the criteria used in our April paper.

The Joskow-Kahn conclusion that the operation of all of these units would have been profitable at real-world prices may be based on calculations that include additional revenues that Joskow and Kahn attribute to the supply of ancillary services,[21] a revenue source not included in our original illustration.[22] It could be appropriate to include estimated ancillary service costs in an assessment of the profitability of unit operation. Recall, however, that the point of our original analysis was to illustrate the impact of alternative assumptions regarding minimum load costs and operating inflexibilities on apparent profitability. If one were interested in the absolute profitability of these units, rather than the change in apparent profitability, it would be necessary to take account of variable O&M costs (not included in the Joskow-Kahn profitability calculations) and to calculate revenues based on the net output available for sale, rather than gross output including electricity consumed at the plant.[23] Table 9 in our April paper noted that we were omitting both of these costs from our illustrative calculations, which as we have observed above, were intended to illustrate the error in profitability estimates if minimum load costs are nor taken into account. Moreover, the Joskow-Kahn estimates of ancillary service revenues have a number of problematic features.

The first limitation of the Joskow-Kahn assessment of ancillary service revenues is that the calculations appear to assume that the same ramping capacity could be used to simultaneously provide AGC, spinning reserve and non-spinning reserve.[24] In reality, the ten-minute ramping capability could be used only to provide ten minutes of ramping capability of spinning and non-

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20 Joskow-Kahn (July), p. 15-16.

21 Joskow-Kahn (July), p. 17.

22 This was pointed out in our paper in observing that our calculations did not reflect the actual day-ahead revenues. Harvey-Hogan (April), footnote 54, p. 28.

23 This was noted in Harvey-Hogan (April) (footnote 52, p. 26 and the notes for Tables 6, 7, 8 and 9). The CEMS data on which we, and Joskow and Kahn, have based these calculations measure the gross output of the units (which includes electricity consumed in operation of the units, i.e., station costs). Other factors not included in these calculations are the actual level of day-ahead sales (day-ahead sales could have been either greater or less than real-time output) and actual incremental emissions (the average emissions data may not reflect actual emissions for these particular dispatch patterns). Moreover, Alamitos 4 and Redondo Beach 5 and 6 were RMR units and may have opted to operate at contract rather than market rates because day-ahead prices were too low to recover their costs.

24 We have not been able to locate the "publicly available" RMR contracts between the generators and the ISOs on which Joskow and Kahn state they relied in their ancillary service analysis. We have, however, obtained similar data for a number of the units from the divestiture disclosure documents. See "Capacity Sale and Tolling Agreement by and among AES Alamitos, L.L.C., AES Huntington Beach, L.L.C., AES Redondo Beach, L.L.C., and Williams Energy Services Company," Schedule A, FERC Docket No. ER98-2184, -2185 and –2186, July 15, 1999. See also "Application for Authority to Sell Specific Ancillary Services at Market-based Rates and Request for Expedited Consideration," FERC Docket No. ER98-2977, May 13, 1998. The Etiwanda units are not included in the discussion below because we have not been able to locate data on their ramp rates.

spinning reserves in total.[25] This assumption serves to overstate ancillary service capacity and revenues. Second, they prorate down the amount of ancillary services any individual unit could hypothetically provide based on total ancillary services supplied. While this adjustment makes their revenue figures look more reasonable, it has no economic basis. If these units could economically supply the assumed amount of ancillary services, they could have bid all of it into the market, not merely a prorated share of it. Thus, this procedure tends to understate potential ancillary revenues and offset the first methodological problem. Third, the ancillary service profit calculations are based on the higher of day-ahead or real-time prices.[26] This approach unambiguously overstates the profits that real-world firms could derive from the sale of ancillary services. Fourth, much of the assumed ancillary service revenues derive from the supply of regulation, but no account is taken in these calculations of the increased operating costs in terms of higher heat rates that are associated with the provision of regulation. The provision of regulation by these steam units would indeed be highly profitable at these prices if it were costless, but it is not costless, which is why regulation prices are high.[27] Fifth, although Joskow and Kahn state that they used RMR data on AGC minimum operating levels,[28] the illustrative calculations they provide assign regulation to several units that appear to have been operating well below their AGC minimums.[29]

To provide a better reflection of plausible ancillary service revenues, we have estimated ancillary services revenues for the units and days in Table 7 above assuming that each unit sold capacity equal to its 10 minute ramp rate (up to total unit capacity) at the day-ahead spinning reserve price, or at the 50-50 weighted average of the day-ahead spinning reserve and non-spinning reserves prices. We have not added any allowance for AGC profits because the calculation of such a profit margin requires knowledge of the cost of providing AGC (in terms of the heat rate performance penalty) on these units. While the inclusion of estimated ancillary services revenues makes operation profitable for one unit on June 23, the operation of several units remains unprofitable on June 17 and 21.

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25 See Yenren Liu, Mark Rothleder, Ziad Alaywan, Mehdi Assadian, and Farrokh A. Rahimi, “Implementing Rational Buyer’s Algorithm at California ISO,” August 17, 2001. Joskow and Kahn “account for how much capacity has already been scheduled for the generator,” p. 33, but the capacity limit appears to have been the total capacity of the unit, rather than the ten-minute ramping capacity.

26 This is not stated in the Joskow-Kahn Reply and Joskow and Kahn did not identify the prices used in this calculation, but it is apparent that revenues reported in Table A2.2 Joskow-Kahn (July), p. 34 were based on hour-ahead ancillary service prices for June 21 as hour-ahead spin and non-spin prices were high while day-ahead prices were quite low. The revenues reported for June 23, however, must have been calculated based on day-ahead prices as non-spin prices were quite low in the hour-ahead market.

27 Although the cost of regulating may at the margin be set by steam units, most of California’s regulation was likely provided by hydro units which do not incur similar costs in providing regulation. The price of regulation would therefore likely be set by the costs of the steam units that could most efficiently provide this service, and the supply of regulation would likely have been uneconomic for run of the mill steam units.

28 Joskow-Kahn (July), p. 32.

29 Joskow-Kahn (July), p. 33. For example, Table A2.1 shows that, according to the CEMS data, in the first hour of June 21, 2000, Alamitos 1 generated 12 MW. Joskow and Kahn ascribe 105 MW of capacity available to provide regulation up. However, according to the “Capacity Sale and Tolling Agreement,” the unit is not AGC capable at this level of output, but needs to produce at 40 MW before it becomes AGC capable. Similarly, Huntington Beach 1 is shown with output of 21 MW, with 129 MW available for regulation up. According to the “Capacity Sale and Tolling Agreement,” this unit is not AGC capable in the 20-65 MW range.

Table 8 High Heat Rate Unit Operating Profitability with Spinning Reserve Revenues				
PX Profits	**June 16, 2000**	**June 17, 2000**	**June 21, 2000**	**June 23, 2000**
Alamitos 1	--	--	(6,066)	18,194
Alamitos 2	273,330	(31,351)	(13,526)	37,800
Alamitos 3	1,456,940	80,771	71,347	290,344
Alamitos 4	1,455,769	85,010	76,070	292,958
El Segundo 1	350,681	--	--	--
El Segundo 2	366,165	--	25,197	(11,273)
El Segundo 3	311,935	34,129	--	211,916
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(13,296)	27,106

Notes:
Ancillary services revenues are calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
CEMS data, adjusted for Daylight Savings Time.
Energy revenues from Table 7.
Calculations do not include variable O&M or station costs.
Day-ahead ancillary service prices were used.

Table 9 High Heat Rate Unit Operating Profitability with Ancillary Service Revenues 50% Spinning Reserve, 50% Non-Spinning Reserve				
PX Profits	**June 16, 2000**	**June 17, 2000**	**June 21, 2000**	**June 23, 2000**
Alamitos 1	--	--	(6,712)	79,657
Alamitos 2	247,884	(31,362)	(14,141)	99,262
Alamitos 3	1,447,841	81,013	70,737	296,573
Alamitos 4	1,442,668	85,090	75,683	302,681
El Segundo 1	325,264	--	--	--
El Segundo 2	340,748	--	24,806	(11,282)
El Segundo 3	281,804	34,107	--	329,572
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(13,343)	88,568

Notes:
Ancillary services revenues are calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
CEMS data, adjusted for Daylight Savings Time.
Energy revenues from Table 7.
Calculations do not include variable O&M or station costs.
Day-ahead ancillary service prices were used.

Moreover, it should be recognized that the profitability portrayed in Tables 8 and 9 is the profitability of generation able to bid into day-ahead markets such as those coordinated by PJM-ISO and the NYISO, in which the generator submits three part bids and its schedule is optimized over the day. California generators did not have the option of bidding into such a market. If such an option existed, perhaps market performance would have been different.[30]

Joskow-Kahn also suggests that real-time revenues could increase the profitability of operation on days with high–real-time prices.[31] This is correct on days on which real-time prices were higher than day-ahead prices, but output that is not sold at day-ahead prices may also be sold at real-time prices that are lower than day-ahead prices, as was the case on June 16, 17 and 23.

In fact, all but one of the nine high cost units we have discussed lost money by operating in real-time on June 16 and 17 (El Segundo 3 on June 16 under one measure of potential real-time ancillary service revenues). That is, with the benefit of perfect hindsight, they should have shut-down and covered their day-ahead positions (if any) at real-time spot prices.[32] This is true whether ancillary service revenues are calculated as 100 percent spinning prices or 50 percent spinning and 50 percent non-spinning prices and even though no account is taken of variable O&M costs or station costs (see Tables 10 and 11). Moreover, on June 23 the more efficient of these plants were profitable to operate at real-time prices, but every one of the high-cost six that was operating, was unprofitable to operate at real-time prices. Once again, with the benefit of 20-20 hindsight, the plants should have been taken off line.

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[30] This point is discussed below in Section F.

[31] Joskow-Kahn (July), p. 17.

[32] Alamitos 4 and Redondo 6 are RMR units and may have had RMR schedules requiring their operation on some or all of these days.

Table 10 High Heat Rate Unit Operating Profitability Actual Real-Time Energy and Spinning Reserve Prices				
	June 16, 2000	**June 17, 2000**	**June 21, 2000**	**June 23, 2000**
Alamitos 1	--	--	372,952	(21,163)
Alamitos 2	(51,046)	(60,799)	442,433	(26,965)
Alamitos 3	(64,412)	(48,602)	1,145,762	71,013
Alamitos 4	(67,557)	(42,219)	1,168,820	72,650
El Segundo 1	(22,822)	--	--	--
El Segundo 2	(19,400)	--	543,904	(12,544)
El Segundo 3	(5,178)	(7,859)	--	51,030
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	528,398	(46,255)

Notes:
Ancillary service revenues are only calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
CEMS data, adjusted for Daylight Savings Time.
Calculations do not include variable O&M or station costs.
Hour-ahead ancillary service prices were used.

Table 11 High Heat Rate Unit Operating Profitability Actual Real-Time Energy and Spinning/Non-Spinning Reserve Prices				
	June 16, 2000	**June 17, 2000**	**June 21, 2000**	**June 23, 2000**
Alamitos 1	--	--	368,233	(21,260)
Alamitos 2	(47,169)	(60,904)	437,788	(27,062)
Alamitos 3	(63,599)	(48,668)	1,123,977	70,534
Alamitos 4	(66,004)	(42,298)	1,167,511	72,187
El Segundo 1	(18,934)	--	--	--
El Segundo 2	(15,512)	--	539,829	(12,819)
El Segundo 3	4,774	(8,061)	--	50,844
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	518,212	(46,352)

Notes:
Ancillary services revenues are only calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
CEMS data, adjusted for Daylight Savings Time.
Calculations do not include variable O&M or station costs.
Hour-ahead ancillary service prices were used.

Overall, the data suggest that the magnitude of the difference between revenues calculated based on incremental heat rates without consideration of operating inflexibilities, and the profitability of real-world operation is sufficiently large for some units to turn apparent highly profitable operation in a simulation into unprofitable operation in the real system.

D. Would More Operation Have Been Profitable?

With this background, let us return to the issue that the Alamitos 2 example was intended to illustrate, that non-chronological simulations based on incremental heat rates have the potential to understate the competitive level of prices, and underestimate the slope of the competitive supply curve because they meet load by dispatching resources that did not operate in the real world and could not operate profitably in the real world.

Going beyond the errors in the calculation of profits, the next question in assessing the impact of this consideration on the Joskow-Kahn simulation results would be to ask whether there were units that were not operating in the real system that would be dispatched to operate in one or more hours on those days in the Joskow-Kahn simulation. And if so, would their operation have been profitable in the real system. We cannot fully address this issue because we do not have access to the actual Joskow-Kahn simulation analysis nor data on which units were dispatched in which hours in the simulation, nor the simulated hourly prices for the Joskow-Kahn results. Based on our understanding of their methodology, however, their analysis dispatched generators to meet load based on the assumed incremental heat rates and NO_x emissions. To approximate this dispatch, we have used the Klein incremental heat rates at full load and the second quarter 2000 average NO_x emissions rate for each unit to calculate incremental dispatch prices (see Table 12). These data are presumably not the precise figures that Joskow and Kahn utilized in their simulation analysis but should be sufficiently similar to illustrate the methodological issues.

Table 12 Incremental Dispatch Price Based on Full Load Incremental Heat Rates										
Unit	**Dispatch Price ($/MW)**	**Klein Full Load Capacity (MW)**	**Klein Full Load Incremental Heat Rate (Btu/kWh)**	**Gas Price ($/ mmBtu)**	**Gas Burned mmBtu**	**Gas Cost ($)**	**Emissions (lb./ mmBtu)**	**Emission Cost ($/lb.)**	**Allowance Cost**	**Total Cost**
	A	B	C	D	E	F	G	H	I	J
Alamitos 1	62.55	175	10,056	4.99	1,760	$8,781	0.123	10	$2,165	$10,946
Alamitos 2	69.19	175	10,056	4.99	1,760	8,781	0.189	10	3,326	12,107
Alamitos 3	53.69	320	9,338	4.99	2,988	14,911	0.076	10	2,271	17,182
Alamitos 4	52.20	320	9,338	4.99	2,988	14,911	0.060	10	1,793	16,704
El Segundo 1	61.78	175	9,901	4.99	1,733	8,646	0.125	10	2,166	10,812
El Segundo 2	62.87	175	9,901	4.99	1,733	8,646	0.136	10	2,356	11,002
El Segundo 3	51.53	335	9,201	4.99	3,082	15,381	0.061	10	1,880	17,261
Etiwanda 1	62.20	132	10,724	4.99	1,416	7,064	0.081	10	1,147	8,210
Etiwanda 2	63.06	132	10,724	4.99	1,416	7,064	0.089	10	1,260	8,324
Etiwanda 3	50.73	320	9,292	4.99	2,973	14,837	0.047	10	1,398	16,235
Etiwanda 4	50.92	320	9,292	4.99	2,973	14,837	0.049	10	1,457	16,294
Redondo Beach 5	63.58	175	9,532	4.99	1,668	8,324	0.168	10	2,802	11,126
Redondo Beach 6	56.52	175	9,532	4.99	1,668	8,324	0.094	10	1,568	9,892

Notes:
A = J/B.
B = Klein (April 1998).
C = Klein (April 1998).
D = Joskow-Kahn.
E = B * C/1,000.
F = (B*C*D)/1,000.
G = 2nd Quarter 2000 CEMS data.
H = Joskow-Kahn.
I = (E*G*H).
J = (F)+(I).

We have not analyzed every day in June, but have selected the period June 1-11 as illustrative of relatively low priced days in early June and the days of June 16, 17, 21 and 23, as illustrative of the higher priced days. We have developed approximations of the profits (based on day-ahead PX prices) of units that were off-line in the real world but would have been dispatched in the Joskow-Kahn simulation by assuming that these units would have been dispatched to operate at full load in all hours in which the real-world price exceeded their incremental dispatch price but further assumed that these units would have operated at minimum load in all other hours of that day. In practice, the units would have been dispatched up and down during some of the hours of the day and from hour to hour, would have been subject to a variety of other ISO instructions, and would have had to incur start-up costs if they were off-line.

It can be seen in Table 13 that under the Joskow-Kahn simulation methodology every one of the eight high cost units that were off-line at times during the June 1 to June 11 period in the real world would have been dispatched in a simulation based on incremental heat rates for at least one hour in every day during the period June 1-June 9 and a few would even be dispatched on

June 10 and 11. This dispatch of additional resources would depress the simulated prices relative to real-world prices, consistent with the findings of the Joskow-Kahn simulation study. The profitability calculations, however, indicate that the operation of a number of these units would have been unprofitable on many of these days, even ignoring start-up costs.

Leaving Alamitos 1 in operation after June 7 would have lost about $40,000 by June 9. The operation of El Segundo 1 would have been profitable on June 3 and 4, but cumulatively the decision to turn the unit off after June 2 had saved about $17,000 by June 11. El Segundo 2 would have made a little money had it turned on June 2 rather than June 5, but it would have lost over $40,000 had it remained on after June 7. El Segundo 3 would have lost almost $80,000 just remaining on for the two days of June 10 and 11. Etiwanda 1 and 2 were not operating and would have lost money had they operated over the June 1-9.[33] Redondo Beach 5 could have operated profitably only on a single day, and would have lost well over $100,000 had the unit operated over the period June 1-9, even ignoring start-up costs.[34]

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[33] Etiwanda 1 and 2 could have operated profitably had they been able to costlessly start on June 2 and shut down on June 4, but this pattern of operating would have required recovery of start-up costs as well as minimum load costs.

[34] It should be kept in mind that these units may have been unavailable in the real world due to forced outages, or maintenance outages needed to restore full capacity on derated units rather than economics.

Table 13
Hypothetical Profits for Off-Line Units Based on Average Heat Rates and SP-15 PX Prices

PX Profit	June 1, 2000	June 2, 2000	June 3, 2000	June 4, 2000	June 5, 2000	June 6, 2000	June 7, 2000	June 8, 2000	June 9, 2000	June 10, 2000	June 11, 2000
Alamitos 1	Running	Running	Running	Running	Running	Running	Running	(11,401)	(29,293)	Off	Off
El Segundo 1	Running	Running	34,356	7,337	(7,750)	(5,017)	(9,248)	(9,232)	(27,901)	Off	Off
El Segundo 2	(28,727)	1,985	31,369	4,523	Running	Running	Running	(12,224)	(29,155)	Off	Off
El Segundo 3	Running	Running	Running	Running	Running	Running	Running	Running	Running	(38,322)	(40,350)
Etiwanda 1	(20,333)	6,351	28,930	8,174	(3,690)	(2,771)	(6,003)	(5,336)	(20,679)	Off	Off
Etiwanda 2	(21,101)	4,710	27,191	5,978	(6,272)	(3,927)	(7,159)	(7,181)	(21,447)	Off	Off
Etiwanda 3	1,729	79,398	129,710	79,582	47,855	46,227	45,652	48,231	(519)	(27,753)	(32,437)
Redondo Beach 5	(37,457)	(8,372)	20,832	(6,047)	(20,896)	(16,819)	(21,058)	(21,858)	(38,123)	Off	Off

Notes:

(1) "Running" means unit was on-line for at least part of the day in the real world per the CEMS data, adjusted for Daylight Savings Time.
(2) "Off" means the unit was off-line in the real world and would not have been dispatched in any hour based on its incremental dispatch price and the SP-15 PX price in the simulation.
(3) Profit calculations:
If SP-15 PX Price ≥ Dispatch Price, then Full Load Revenues minus Full Load Costs (average heat rate).
If SP-15 PX Price < Dispatch Price, then Block 1 Revenue minus Block 1 Costs (average heat rate).
(4) Assumptions:
Max Capacity = Klein Block 5 Capacity.
Min Capacity = Klein Block 1 Capacity.
Average heat rates from Klein.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions rates per CEMS.
PX prices are SP-15 zonal PX prices.
(5) Alamitos 2, 3 and 4, Etiwanda 4 and Redondo Beach 6 were running throughout this period.

Overall, the dispatch of uneconomic units would have added over 1,000 MW of generation on every day other than June 3 over the period June 1-11. Furthermore, the dispatch of uneconomic generation would have exceeded 4,000 MW on every day between June 4 and June 10, as shown in Table 14.

Table 14
Simulated Output of Unprofitable Off-Line Units
Klein Capacity and Uncapped Prices

PX Profit	June 1, 2000	June 2, 2000	June 3, 2000	June 4, 2000	June 5, 2000	June 6, 2000	June 7, 2000	June 8, 2000	June 9, 2000	June 10, 2000	June 11, 2000
Alamitos 1	Running	Running	Running	Running	Running	Running	Running	1,400	525	Off	Off
El Segundo 1	Running	Running	--	--	1,925	1,400	1,400	1,750	525	Off	Off
El Segundo 2	525	--	--	--	Running	Running	Running	1,400	525	Off	Off
El Segundo 3	Running	Running	Running	Running	Running	Running	Running	Running	Running	2,680	670
Etiwanda 1	396	--	--	--	1,452	924	924	1,188	396	Off	Off
Etiwanda 2	396	--	--	--	1,188	924	924	1,056	396	Off	Off
Etiwanda 3	--	--	--	--	--	--	--	--	4,800	3,520	1,280
Redondo Beach 5	525	2,100	--	1,925	1,575	1,225	1,225	1,400	350	Off	Off
Total	1,842	2,100	0	1,925	6,140	4,473	4,473	8,194	7,517	6,200	1,950

Notes:
(1) "Running" means unit was on-line for at least part of the day in the real world per the CEMS data, adjusted for Daylight Savings Time.
(2) "Off" means the unit was off-line in the real world and would not have been dispatched in any hour based on its incremental dispatch price.
(3) "Simulated Output" is the total calculated output for hours in which the SP-15 PX Price >= Dispatch price on days on which operation would have been unprofitable over the day as a whole evaluated at day-ahead prices (per Table 13).

As before, the analysis of profitability we have undertaken is meant to be illustrative and does not provide a complete assessment of the profitability of operating these units in additional hours. First, the calculations overstate revenues because they are based on Klein capacities, which measure gross output, not the net output that was available for sale. Second, no account is taken of deratings that might have prevented some of these units from operating at capacity (or at all) during this period. Third, the calculations assume all of the output could have been sold at day-ahead prices, which would not have been feasible under the California market design for potentially marginal firms lacking perfect foresight.[35] Fourth, the calculations do not take account of ancillary service revenues.[36] Fifth, the calculations take no account of CAISO dispatch instructions, ramp rates, or environmental output limits. Sixth, the calculations do not include any allowance for variable O&M. Seventh, the Klein heat rates may differ from the actual heat rates under these operating conditions.

To be clear, the point here is not that we have demonstrated that these units would surely be unprofitable. The point is that there is reason to believe the simulation of electric output based on full load incremental heat rates without regard to minimum load costs, start-up costs, average heat rates or physical unit constraints has the potential to dispatch significant amounts of uneconomic generation and thereby systematically understate the competitive price level.

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[35] We address this point below.

[36] We also discuss this point further below.

Table 15 includes in this calculation of profits for the days June 1-11 the estimated ancillary service revenues of each unit from selling capacity in the spinning reserve market at day-ahead prices. It is again seen that units that would have been dispatched based on their incremental heat rates would often have been unprofitable to operate taking minimum load costs into account.

Table 15

Hypothetical Profits for Off-Line Units Scheduled at SP-15 PX Prices Based on Incremental Heat Rates Including Spinning Reserve Revenues at Day-Ahead Prices

PX Profit	June 1, 2000	June 2, 2000	June 3, 2000	June 4, 2000	June 5, 2000	June 6, 2000	June 7, 2000	June 8, 2000	June 9, 2000	June 10, 2000	June 11, 2000
Alamitos 1	Running	Running	Running	Running	Running	Running	Running	(9,817)	(26,608)	Off	Off
El Segundo 1	Running	Running	35,377	8,636	(5,783)	(2,654)	(7,261)	(8,017)	(25,215)	Off	Off
El Segundo 2	(25,847)	5,750	32,390	5,822	Running	Running	Running	(10,641)	(26,470)	Off	Off
El Segundo 3	Running	Running	Running	Running	Running	Running	Running	Running	Running	(34,893)	(35,795)
Redondo Beach 5	(34,577)	(4,606)	21,853	(4,713)	(18,440)	(14,185)	(18,809)	(20,274)	(35,119)	Off	Off

Notes:
(1) "Running" means unit was on-line for at least part of the day in the real world per the CEMS data, adjusted for Daylight Savings Time.
(2) "Off" means the unit was off-line in the real world and would not have been dispatched in any hour based on its incremental dispatch price and the SP-15 PX price.
(3) Profit calculations, by hour, summed over the day:
If SP-15 PX Price ≥ Dispatch Price then Full Load Revenues minus Full Load Costs (average heat rate).
If SP-15 PX Price < Dispatch Price then Block 1 Revenue minus Block 1 Costs (average heat rate).
(4) Assumptions:
Max Capacity = Klein Block 5 Capacity.
Min Capacity = Klein Block 1 Capacity.
Average heat rates from Klein.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions rates per CEMS.
PX prices are SP-15 zonal PX prices.
Spinning reserve revenues equal ten-minute ramp rate * SP-15 day-ahead spinning reserve price.

We also undertook the same calculation including reserve revenues assuming that 50 percent of the unit's ramping capacity was sold as spinning reserve and 50 percent as non-spinning reserve. Once again, operation was often unprofitable if evaluated based on day-ahead prices and real-time schedules.

Table 16 Hypothetical Profits for Off-line Units Scheduled at SP-15 PX Prices Based on Incremental Heat Rates Includes Ancillary Service Revenues for 50% Spinning/50% Non-Spinning at Day-Ahead Prices											
PX Profit	**June 1, 2000**	**June 2, 2000**	**June 3, 2000**	**June 4, 2000**	**June 5, 2000**	**June 6, 2000**	**June 7, 2000**	**June 8, 2000**	**June 9, 2000**	**June 10, 2000**	**June 11, 2000**
Alamitos 1	Running	Running	Running	Running	Running	Running	Running	(10,465)	(27,562)	Off	Off
El Segundo 1	Running	Running	34,910	8,039	(6,709)	(3,585)	(7,974)	(8,563)	(26,169)	Off	Off
El Segundo 2	(26,999)	3,915	31,923	5,225	Running	Running	Running	(11,288)	(27,424)	Off	Off
El Segundo 3	Running	Running	Running	Running	Running	Running	Running	Running	Running	(36,162)	(37,617)
Redondo Beach 5	(35,728)	(6,442)	21,385	(5,319)	(19,494)	(15,197)	(19,588)	(20,922)	(36,198)	Off	Off

Notes:
(1) "Running" means unit was on-line for at least part of the day in the real world per the CEMS data, adjusted for Daylight Savings Time.
(2) "Off" means the unit was off-line in the real world and would not have been dispatched in any hour based on its incremental dispatch price and the SP-15 PX price.
(3) Profit calculations, by hour, summed over the day:
If SP-15 PX Price ≥ Dispatch Price then Full Load Revenues minus Full Load Costs (average heat rate).
If SP-15 PX Price < Dispatch Price then Block 1 Revenue minus Block 1 Costs (average heat rate).
(4) Assumptions:
Max Capacity = Klein Block 5 capacity.
Min Capacity = Klein Block 1 capacity.
Average heat rates from Klein.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions rates per CEMS.
PX prices are SP-15 zonal PX prices.
Spinning reserve revenues equal ten-minute ramp rate (.5 * SP-15 day-ahead spinning reserve price + .5 * SP-15 day-ahead non-spinning reserve price).

Although in a well designed electricity market an on-line generator would always find it most profitable to offer all of its ramping capacity as spinning reserve, this would not be rational in the California electricity market. The combination of sequential clearing of ancillary service markets and the "rational buyer protocol," makes it unprofitable for a competitive on-line generator to offer all of its ramping capacity in the spinning reserve market at cost, but instead requires that generators structure their bids to guess the market clearing price.

E. Would Operation Have Been Profitable at Simulated Prices?

Now we turn to another question, for the units that were operating on high priced days in June, would their operation still have been profitable at the prices simulated by Joskow and Kahn? Joskow-Kahn also does not address this issue in the reply, instead assessing whether it was profitable for the plants that were actually operating in the real world to operate at real-world day-ahead prices. The issue raised by their simulation results, however, is not the profitability of operating these plants at real-world prices, but whether these units would have been profitable to operate at the simulated prices. As above, we cannot provide a full answer to this question without the hourly prices simulated by Joskow and Kahn. We can, however, provide an indication of the answer by capping real-world energy prices at $142.96/MWh[37] and asking whether all of the units that were actually operating on some of the high priced days would still have been profitable to operate. Table 7 above portrayed the profitability of operating the 13 high cost units on June 16, 17, 21 and 23 excluding ancillary service revenues. There were six instances of days on which the six highest cost units operated but would have lost money based on real-world PX prices. This profitability calculation has then been repeated with PX prices capped at $142.96, approximating the price level simulated by Joskow and Kahn. It can be seen in Table 17 that there are an additional three instances (Alamitos 2 on June 16 and June 23; Redondo Beach 6 on June 23) of units that operated in the real world but would not have been profitable to operate at simulated prices.

Table 17
High Heat Rate Unit Operating Profitability
Day-Ahead SP-15 Prices Capped at $142.96

	June 16, 2000	June 17, 2000	June 21, 2000	June 23, 2000
Alamitos 1	--	--	(13,144)	(10,296)
Alamitos 2	(5,218)	(34,585)	(20,502)	(4,289)
Alamitos 3	348,634	79,746	65,164	193,455
Alamitos 4	348,084	83,242	72,084	194,953
El Segundo 1	33,396	--	--	--
El Segundo 2	38,911	--	19,904	(12,230)
El Segundo 3	17,505	27,937	--	117,004
Etiwanda 1	72,245	--	--	--
Etiwanda 2	56,070	--	--	--
Etiwanda 3	248,256	66,865	(998)	177,010
Etiwanda 4	215,765	51,400	(315)	183,192
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(18,235)	(19,370)

Notes:
CEMS heat rates.
Gas Price = $4.99.
Allowance Cost = $10/lb.
Emissions rates per CEMS.
Calculates are based on CEMS data, adjusted for Daylight Savings Time.
Calculations do not include variable O&M or station costs, or potential ancillary services revenues.

[37] If real-world PX prices were capped at $142.96/MWh, the average June PX price would be $74.03/MWh, which is equal to the figure reported by Joskow and Kahn for their simulation model. We realize that this is only a rough approximation of the prices they estimated, as our methodology likely reduces prices above $142.96 by more than they fell in the Joskow-Kahn simulation and reduces prices below $142.96 by less than they fell in the Joskow-Kahn simulation. Lacking access to the Joskow-Kahn simulation prices, this appears to be a reasonable approach to illustrating the underlying conceptual issue.

The impact of the lower prices in the simulation would have therefore been to reduce output by 2,298 MW on June 23, relative to the real world. (Redondo 6 is an RMR unit and, if constrained on for RMR, would have operated regardless of PX prices.)

The calculations in Table 17 do not include ancillary service revenues, but including estimates of these revenues does not change the conclusion that less output would have been available at the simulated prices than was available in the real world (see Table 18).[38] Thus, if ancillary service revenues are estimated based on spinning reserve prices, operation of Alamitos 1 would have been profitable on June 23 at actual prices (see Table 8) and unprofitable at capped prices. A shutdown of this unit would have reduced energy supply on June 23 by a total of 723 MW. Moreover, the operation of Alamitos 2 and Redondo Beach 6 is barely profitable at capped prices.

Table 18
High Heat Rate Unit Operating Profitability with Spinning Reserve Revenues
Energy Prices Capped at $142.96, Ancillary Services Prices Capped at $30

PX Profits	June 16, 2000	June 17, 2000	June 21, 2000	June 23, 2000
Alamitos 1	--	--	(8,258)	(305)
Alamitos 2	9,998	(31,351)	(15,719)	5,702
Alamitos 3	353,579	80,771	69,884	196,428
Alamitos 4	355,631	85,010	74,817	198,631
El Segundo 1	48,486	--	--	--
El Segundo 2	54,000	--	23,757	(11,273)
El Segundo 3	39,859	34,129	--	136,128
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(14,487)	2,815

Notes:
Ancillary revenues are only calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
Energy revenues from Table 17.
Calculations do not include variable O&M or station costs.

Similarly, the operation of El Segundo 2 would have been unprofitable on June 23 with real-time output priced at capped day-ahead prices and ancillary service revenues based on 50 percent spinning reserve price and 50 percent non-spinning reserve price, and the operation of Alamitos 1 and 2 would have been barely profitable.

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[38] Ancillary service prices have also been capped at $30, consistent with the conclusions of Joskow-Kahn (July), p. 9.

Table 19
High Heat Rate Unit Operating Profitability with Ancillary Service Revenues
50% Spinning Reserve/50% Non-Spinning Reserve
Day-Ahead Energy Prices Capped at $142.96, Ancillary Services Prices Capped at $30

PX Profits	June 16, 2000	June 17, 2000	June 21, 2000	June 23, 2000
Alamitos 1	--	--	(7,983)	63
Alamitos 2	7,552	(31,362)	(15,412)	6,070
Alamitos 3	352,285	81,013	69,950	196,396
Alamitos 4	354,043	85,090	75,007	198,722
El Segundo 1	46,068	--	--	--
El Segundo 2	51,583	--	23,971	(11,282)
El Segundo 3	37,005	34,107	--	136,834
Redondo Beach 5	--	--	--	--
Redondo Beach 6	--	--	(14,058)	64,277

Notes:
Ancillary revenues are only calculated for those hours in which the unit had positive generation.
Etiwanda units are not included because we lack ramp rates for those units.
Energy revenues from Table 17.
Calculations do not include variable O&M or station costs.

We reiterate that these calculations do not reflect the actual profitability of any of these units. These calculations do not reflect variable O&M costs, are based on gross, not net, output, value real-time output at day-ahead prices, and assume that unloaded capacity could have been fully scheduled to provide ancillary services. The point of these calculations is directional, taking account of minimum load costs and operating inflexibilities can materially impact the calculated profitability of operating units to meet load, and simulations that ignore these costs may not simulate the competitive equilibrium level of prices.

F. Does Market Design Matter?

A final point regarding these profitability assessments is that they illustrate the reality that the California market design is indeed an important issue in understanding generator bidding behavior. In particular, the lack of three-part bids in the PX day-ahead energy market, separation of the energy and ancillary service markets, sequential clearing of the ancillary service markets and lack of effective congestion management mechanisms either day-ahead or in real time, are all critical limitations of the California market design that have potentially substantial impacts on market outcomes. Joskow-Kahn asserts that market design is not part of the problem, stating that:

> "Finally, we may ask if the inefficient dispatch was somehow caused by the inefficiencies in the market design alleged by Harvey & Hogan. With the amount of daily capacity adjustment illustrated in Table 12, it seems difficult to argue that generators were somehow prevented by market rules from turning on their

> capacity when it was economic. The more plausible hypothesis is that generators were withholding at least some of the capacity listed in Table 13."[39]

We disagree. The issue is, of course, not whether generators were prevented from turning on their capacity, but whether the market design facilitated or hindered efficient unit commitment decisions. As discussed more fully below, Table 12 in Joskow-Kahn does not actually provide a good indication of how much capacity was generally being turned on and off on a daily basis. Even if it did, however, this would not support a conclusion that market design is unimportant. The more capacity is potentially turned on and off every day, the more important it will be to have an efficient market-based unit commitment process. This process must permit market participants to ensure that the right units are turned on and off and that an efficient tradeoff is made between the commitment of inflexible units with high start-up costs and low incremental costs and quick start units with higher incremental costs. Joskow-Kahn argues such problems are immaterial.

We believe that several elements of the California market design are important in understanding California market performance. As Joskow has observed for the early operation of the California market:

> "Flaws were identified in the congestion management system, with the contracts designed to mitigate local market power problems [footnote in original], the protocols for planning and investment in transmission and the interconnection of new generating plants, the real time balancing markets, the ancillary services markets, under-scheduling before real time operations, and other areas. These market design flaws increased the costs of ancillary services far above projections, led to scheduling and dispatch inefficiencies, slowed down investment in new power plants, increased the costs of managing congestion, increase spot market price volatility, and increased wholesale market prices generally."[40]

It is unlikely that the analysis of the exercise of market power is immune from these general defects which continued in California through the period of study.

1. Three-Part Bids

First, the lack of three-part bids in the PX day-ahead market means that under the California market rules there is no bidding strategy (other than having perfect foresight) that would enable generators to bid in such a manner as to ensure that they are fully scheduled in the day-ahead energy market when it is economic for them to operate, without risking being scheduled to operate when it is not economic for them to operate. In the day-ahead markets coordinated by the PJM and New York ISOs, a generator could submit cost-based three-part bids that would enable its unit to be fully scheduled, based on its bids, without risking uneconomic commitment.

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[39] Joskow-Kahn (July), p. 25.

[40] Paul M. Joskow, "California's Electricity Crisis," MIT Working Paper, November 2001, (forthcoming *Oxford Review of Economic Policy*), pp. 21-22.

It is an explicit design feature of the CAISO market to make it impossible for generators to bid in this manner.

As a practical matter, therefore, while a generator in PJM or New York lacking perfect foresight can readily submit cost-based bids that ensure that their units would be fully scheduled at day-ahead prices and would sell additional output at real-time prices if real-time energy prices exceeded day-ahead energy prices, this is not the case in California. The California market design makes it likely that the marginal generators will not be economically scheduled in the day-ahead PX market and will potentially sell additional output in real time at prices that may be lower than day-ahead prices. Thus, in calculating energy revenues in the examples above, we assumed for illustrative purposes that all of the real-time output had been sold at day-ahead prices or that all of the output that would have been profitable to sell at day-ahead prices could have been sold at day-ahead prices. While units that know they will be infra-marginal can accomplish this by bidding their incremental costs into the PX market, there is no bidding strategy that would permit marginal generators, such as those we have attempted to analyze above, to accomplish this, without risking being uneconomically committed at prices that do not recover their costs.[41] Moreover, one cannot assess the importance of this consideration by analyzing the profitability of units committed on days on which the PX prices turned out to be high, because part of the uncertainty is whether day-ahead prices will on average be high enough over the day to recover the costs of operating or high only in a single hour.

2. Market Separation

A second and related problem is that this lack of any bidding strategy that would enable a generator to offer capacity in a manner that ensures that it is scheduled to operate if it is profitable but that it is not scheduled to operate unprofitably is further aggravated by the separation of the energy and ancillary service markets. Like the New York electricity market, the California market has explicit ancillary service markets. Unlike the markets coordinated by the New York ISO, however, the California energy and ancillary service markets are cleared sequentially. Marginal generators submitting bids into the California day-ahead energy markets must therefore also factor into their energy market bids a guess as to their likely ancillary service revenues. Failure to guess correctly that ancillary service prices would be high, could cause a potentially marginal generator to submit one part energy bids in the PX that cause it not to clear in the day-ahead market, despite day-ahead prices for energy and ancillary services that in retrospect would have made it profitable to operate.

3. Sequential Ancillary Service Markets

Even worse, the California day-ahead market design has a related third problem, that the ancillary service markets themselves are cleared sequentially, and there is no cost-based bidding strategy, and no bidding strategy at all other than perfect foresight, that would enable an on-line generator to bid so as to ensure that it is paid the market price of spinning reserves. The problem

[41] Even units whose output has been fully sold in forward markets need to make a daily evaluation of whether it would be lower cost to cover their forward sales by operating, purchasing power in bilateral markets or buying power in the spot market.

is illustrated by the spinning and non-spinning reserve prices for June 23 in our discussion above. Despite the fact that all spinning reserves satisfy the requirement for non-spinning reserves, capacity scheduled to provide spinning reserves was paid a substantially lower price day ahead than capacity scheduled to provide non-spinning reserves on June 23. In order to capture the high non-spinning reserve prices that could have made it economic to keep a unit on line, a generator had to hold capacity out of the energy market, and out of the spinning reserve market. Such a bidding strategy, of course, risks forgoing high prices in these markets in return for low prices in the ten-minute market if there is no shortage in the ten-minute reserve market.[42]

In bidding into the day-ahead PX energy market, a generator would need to not only make an assessment of how to bid energy to avoid being uneconomically committed based on its one part bid, but also guess whether it should hold some capacity back to sell in the ancillary service markets at higher prices, and then decide which ancillary service market it should offer its capacity at what reservation price.

4. Congestion Management

Fourth, the CAISO market is confounded with inefficiencies and inconsistencies because of the lack of an effective congestion management system. Unlike electricity markets in PJM and the NYISO, the CAISO market design is intended to separate congestion management from the energy dispatch. The effects of this poor market design have plagued the California market since start-up, and led the CAISO to increasingly rely on command and control, rather than markets, to manage the system. These deficiencies had caused the FERC to find the CAISO's congestion management system to be "fundamentally flawed," and direct reform, well prior to the summer of 2000.[43]

The lack of locational marginal pricing (LMP) led to amendment 19, that although ultimately rejected by the FERC, likely deterred the construction of the new generating capacity California needed in 2001.[44] Moreover, the zonal pricing system precluded development of an effective real-time congestion management system and produced a system in which California generators were being dispatched by both the Gen desk (zonal markets) and an RMR desk (intra-zonal congestion management) leading to inconsistencies in both real-time dispatch and real-time pricing.

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[42] Moreover, such a strategy would require that the generator submit bids that would not be directly related to its costs, making it at best difficult and possibly impossible to determine whether the generator was seeking to exercise market power or merely to be paid the market price. Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000 (hereafter Harvey-Hogan (October)), pp. 4-14.

[43] FERC Docket No. ER00-555-000, January 7, 2000.

[44] Amendment 19 proposed to impose discriminatory charges and pricing systems on new generation built in California in order to reduce "intra-zonal" congestion and avoid the need for LMP pricing. Amendment 19 was dropped in January 2000 in response to FERC opposition, only a few months before the shortages began.

5. Bid Production Cost Guarantee

The bid production cost guarantee is a fundamental element of the electricity markets coordinated by PJM and the NYISO but absent in California. The bid production cost guarantee ensures a generator that if it is dispatched or otherwise instructed by the system operator to generate electricity, it will recover at least its as-bid costs, even if that generation turns out for some reason to be uneconomic evaluated at settlement prices. This concept is applied to units scheduled to operate in the day-ahead market in the circumstance in which LMP market revenues are insufficient to recover the units start-up, minimum load and incremental energy costs over the day (which can be the case for units committed at the margin to provide reserves, to meet forecast load, or occasionally as a result of unit lumpiness). This concept is also applied to units instructed to operate in real-time, in particular quick start units which, once started, must remain in operation for a period of time, even if electricity prices quickly fall below the units offer price.

The reasoning underlying the PJM and NYISO bid production cost guarantee is reliability driven. If the system operator directs a generator to increase output, that generator should not be put in the position of needing to assess the likely profitability of following that dispatch instruction and then deciding how to respond to the dispatch instruction. The lack of a similar bid production cost guarantee in California, and related elements of the CAISO overall real-time settlements rules may have market as well as reliability impacts by at times reducing the supply response to CAISO dispatch instructions and making the supply response in general less predictable by the CAISO.

6. Materiality of Market Design

Joskow-Kahn suggests that market design concerns are not material because they found that the operation of the merchant units that actually operated was always profitable based upon day-ahead prices.[45] But the argument does not support the conclusion. First, as discussed above, the operation of these units would not always have been profitable even on the days that turned out to be high priced, if evaluated based on these hypothetical revenues.

Second, as noted above, part of the problem is that there is no bidding strategy that would enable generators to realize these hypothetical revenues. Both our calculations and those of Joskow and Kahn illustrate what the generators would have realized had they been able to bid so as to sell their output at day-ahead prices without being uneconomically committed (i.e., with perfect foresight). Their calculations do not show what the generators actually earned. The impact of the California market design would be seen precisely in the extent to which actual generator net revenues are lower than calculated based on day-ahead prices. On days when real-time prices are lower than day-ahead prices, our calculations could understate the profitability of generators that operated but sold more in the day-ahead market than they generated in real time, but would overstate the profitability of generators that sold less in the day-ahead market than they generated in real time. Conversely, when real-time prices are higher than day-ahead prices, our calculations would understate the profitability of generators that sold less in the day-ahead market than they produced in real time, but would overstate the profitability of those that

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[45] Joskow-Kahn (July), p. 18.

operated but generated less in real time than they sold day ahead (as would be the case for generators that decided to close out unprofitable positions in the day-ahead market by purchasing power in the real-time market).

Table 20 portrays the day-ahead energy and ancillary service prices for SP-15 during the on-peak hours of June 13. This is a day in which the day-ahead PX prices were relatively low but the real-time prices were higher. The high real-time prices might simply reflect unexpected changes in weather conditions and have been unavoidable under any market design. The lack of centralized unit commitment and sequential markets for energy and ancillary services might also have contributed to the high real time price. It can be seen in Table 20 that while the PX prices, determined early in the day on June 12, averaged 114.24 for the 16 on peak hours, the price of spinning reserve greatly exceeded the PX energy price in hours ending 11, 19, 20 and 21 and averaged $109.48 for the on-peak hours. Furthermore, the price of non-spinning reserve greatly exceeded the price of both energy and spinning reserve in hours ending 11-12 and 15-21, averaging $338.96 for the on-peak hours. This pattern suggests to us that the PX energy prices cleared at too low a price, possibly causing some units not to offer capacity for ancillary services or to offer capacity only at very high prices, with the capacity shortage showing up in non-spinning reserves. While it may be that every available unit was in fact committed on June 13, this is one type of situation in which the California market design may lead to inefficient outcomes and inefficiently high prices.

Table 20 Day-Ahead Energy and Ancillary Services Prices, On-Peak Hours							
Date	**Hour Ending**	**SP-15 PX Price**	**Regulation Down Price**	**Regulation Up Price**	**Spin Price**	**Non-Spin Price**	**Replace-ment Reserve Price**
6/13/00	8	46.26	59.00	14.25	4.00	0.99	1.12
6/13/00	9	50.00	41.00	14.25	7.01	1.29	25.00
6/13/00	10	56.20	41.00	33.16	5.10	55.00	745.11
6/13/00	11	74.85	38.74	651.11	250.00	749.00	749.00
6/13/00	12	82.28	39.64	721.11	35.00	749.00	747.47
6/13/00	13	129.02	60.01	82.00	46.31	33.00	749.11
6/13/00	14	177.11	79.25	155.00	99.00	33.00	749.11
6/13/00	15	204.01	60.00	155.00	99.00	250.00	749.11
6/13/00	16	222.17	65.45	155.00	99.00	400.00	749.11
6/13/00	17	205.41	60.42	155.00	99.00	449.00	749.11
6/13/00	18	157.01	45.90	155.00	99.00	449.00	749.11
6/13/00	19	110.82	37.00	451.11	300.00	749.11	748.11
6/13/00	20	83.55	37.00	551.11	300.00	749.00	749.00
6/13/00	21	79.27	37.00	451.11	300.00	749.00	749.00
6/13/00	22	79.14	31.24	39.58	8.18	6.00	150.00
6/13/00	23	70.70	28.71	21.78	1.00	0.98	0.01
Average		114.24	47.59	237.85	109.48	338.96	572.40
Source: Price data from CAISO website.							

Third, Joskow and Kahn's profitability calculations were limited to days that turned out after the fact to have high day-ahead prices. As we showed in Table 13 there were also many units that would have been unprofitable had they operated on days on which there were no high priced hours. Part of the bidding problem for generators in the California market is how they can bid so as to ensure that they are committed on days on which day-ahead prices are high enough to cover operation while not being committed on days in which day-ahead prices were not high enough to cover operation. Thus there are, in fact, numerous examples of generators whose operation appears unprofitable at day-ahead prices.

It is particularly important that the California market design inevitably causes generators to become financially committed to day-ahead schedules that they cannot profitably cover through operation. This is inevitable because, absent perfect foresight, there is no way for generators to bid so that they are only committed if their revenues over the day exceed their start-up, minimum load and incremental energy costs over the day. Our analysis, as well as that of Joskow and Kahn, has been limited to evaluating the profitability at day-ahead prices of generators that actually operated in real time. Generators that inadvertently become uneconomically committed at day-ahead prices in the PX will not necessarily operate in real time but may instead close out their position financially by buying power in the real-time market. The magnitude of the losses they incur relative to their schedule cannot be determined from publicly available data.

Fourth, apparently uneconomic commitment decisions at day-ahead prices may not always even reflect generator decisions, as some of these units may have been committed by the CAISO under RMR contracts. As noted above, Alamitos 4 and Redondo Beach 5 and 6 were all RMR units and may have been committed on some days based on contract rather than market prices.

In fact, therefore, the Joskow-Kahn analysis provides no further information on whether the design of the California market led to inefficient commitment decisions.

G. Summary on Alamitos 2 and Similar Examples

Overall, rather than the Alamitos 2 example being in some sense artificial or misleading, it provides a reasonable illustration of the principle that simulation studies that fail to account for start-up costs, minimum load costs, and operating inflexibilities will meet load with generation resources that may not have operated profitably in the real world. As a result, such studies do not provide sufficient information regarding the competitive level of electricity prices. The Joskow-Kahn simulations fall in this category. The simulations are suggestive of areas that need further analysis. But the simple simulation results do not dispose of the difficult empirical problems in analyzing the possible exercise of market power.

III. REVISED PRICE SIMULATION ANALYSES

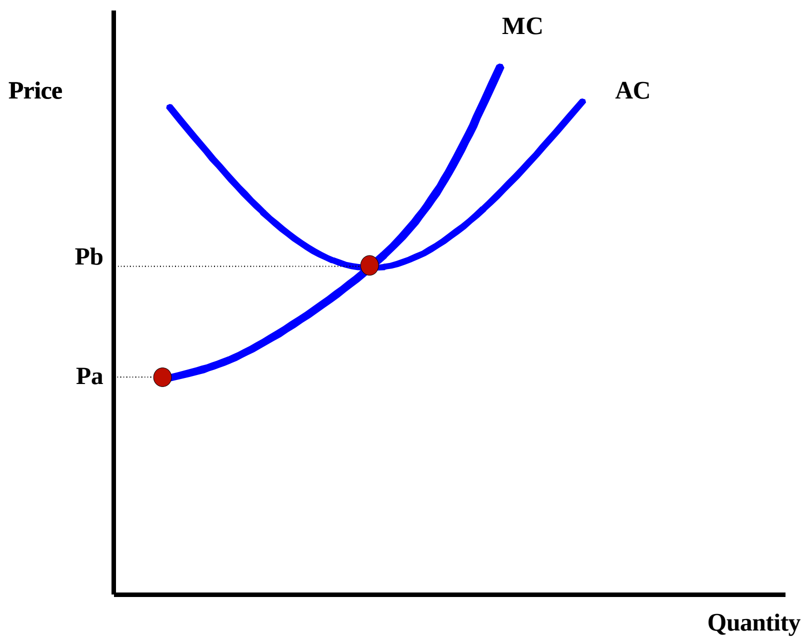
Joskow and Kahn revise their simulation analysis and find that their conclusions are unchanged. While the revised paper addresses a few of the issues we have identified with simulation studies of this type, the paper bypasses several of the major concerns we have previously identified and exacerbates, rather than addresses, others. In particular, Joskow-Kahn's revised simulation analysis does not take any account of start-up and no-load costs (and related unit inflexibilities), environmental output limits (other than emission allowance costs), models outages as uniform capacity deratings and makes no allowance for the impact of deratings or similar output limitations. Moreover, the new simulations have new limitations arising from a material understatement of real-world operating reserve requirements.

A. Start-Up and Minimum-Load Costs

Omitting start-up and minimum-load costs and operating inflexibilities from a simulation of the California or any other electricity market will tend to overstate the supply available at a given price in the high price hours (the simulated supply curve will be too flat) and will cause the simulated prices to understate the competitive price level. As discussed above, Joskow-Kahn considers in the reply the profitability of the units that actually operated in the real world, but never provide any theoretical or empirical response to the limitation we identify with prices simulated assuming the absence of start-up and minimum costs and unit inflexibilities. In particular, they do not demonstrate or explain why the units dispatched to meet load in their simulation model that were not operating in the real world, i.e., the incremental supply that serves to reduce the simulated prices, would have been profitable to operate in the real world. The examples discussed above for June 1-11 and June 16, 17, 21 and 23 suggest the reverse.

The difference can be illustrated in terms of a conventional economic construct, the U-shaped firm average cost curve (AC) portrayed in Figure 21. Having entered, the firm portrayed in Figure 21 might operate anywhere along its marginal cost curve (MC) in a particular period. Now suppose that this firm has not yet entered the industry, or in the metaphor of the electric industry it has not started up. Is the minimum price at which it will supply output Pa or Pb? The Joskow-Kahn approach assumes that the equilibrium price would be at Pa or below, as firms like this would enter whenever the price rose above Pa, their lowest marginal cost. We assume that the equilibrium price could be as high as Pb, because firms would not enter (i.e., start–up) unless they expect to recover their average costs.

Figure 21



Although Joskow and Kahn state that "We agree with the spirit of chronological analysis that Harvey & Hogan introduced with their Alamitos 2 example. We present a more complete version of our previous findings in this style."[46] But in the event, the simulation analysis is entirely non-chronological and ignores operating inflexibilities. In the Joskow-Kahn simulation, steam units

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46 Joskow-Kahn (July), p. 21.

can start up at zero cost to serve load during a single high priced hour, then shut down, units that have shut down can immediately restart, pumped storage units do not have to pump in the hours before they use their water, hydro units can use their water in the highest load hours of the month without regard to pondage constraints. All of these features reduce the cost of meeting load in the simulation relative to the real world, but the difference does not reflect the absence of market power, only the absence of real-world operating inflexibilities.

The importance of start-up and minimum load costs were magnified during June 2000 by changes in RMR contracts between 1999 and 2000. During 1999, 12,011 MW (based on Klein capacities) of the units analyzed by Joskow and Kahn were designated as RMR units. During the summer of 2000 this fell to 6,103 MW. We have seen indications that during 1999 the CAISO was not only using the RMR contracts to manage intra-zonal congestion but was also using these contracts to put otherwise uneconomic units on at minimum load, thereby making their capacity available at incremental cost when needed during the day. The substantial reduction in the amount of RMR capacity available to the CAISO during the summer of 2000 would have limited the ability of the CAISO to manage prices by putting uneconomic units on line. Moreover, the drop in RMR status was proportionately larger among the high cost units in the south discussed above, with the RMR capacity falling from 2,929 in 1999 to 670 MW in 2000.

In addition, June 2000 was also the date at which the CAISO implemented pre-scheduling of RMR units. Prior to June 2000, the CAISO determined RMR schedules after the PX cleared and the CAISO cleared its day-ahead schedules, potentially leading to an inefficient unit commitment but permitting the CAISO to schedule additional RMR generation at minimum load to manage the real-time market based on the amount of energy that cleared in the PX or day-ahead bilateral markets. Beginning in June 2000, the CAISO determined day-ahead RMR schedules prior to the PX market and generators with RMR schedules were required to scheduled their energy in the day-ahead market, and could choose to be compensated at either contract or market (i.e., PX or bilateral) prices.[47]

B. Environmental Restrictions

Joskow and Kahn agree with our comment that cumulative environmental restrictions must be taken into account in analyzing CAISO prices and output, but suggest that these restrictions did not impact the CAISO market until July or August and that environmental limits need not be taken into account in analyzing June prices. We agree that cumulative output limits were likely less important in June than they became in later months but this is not the same as having no impact. Units that had exhausted their annual hours of operation by July would very likely have been impacted by late June. Similarly, given the extremity of the constraints that AES hit later in the year when AES was forced to shut down much of its generation because if cumulative environmental limits, it is not obvious that those constraints did not begin to influence behavior by late June. Reliable conclusions cannot be drawn from simulation models regarding the

[47] Day-ahead LMP markets such as those coordinated by PJM and NYISO clear “intra-zonal” congestion neither before nor after the energy market but simultaneously with the energy market. The CAISO was unwilling to do this because it would have entailed adopting LMP pricing mechanisms. California loads and generators bore the costs of the resulting inefficiency.

exercise of market power as opposed to the impact of environmental limits if the environmental limits are simply ignored in the simulation models. As we stated in our April paper:

> "There is more than one way to model these environmental limits, and reasonable people will likely differ on the most appropriate approach. It may in fact be desirable to simulate prices using a range of approaches to understand the sensitivity of the simulation results to these assumptions. It does seem clear, however, that it is not sufficient to simulate electricity prices for California in 2000 under the assumption that none of these environmental limits existed."[48]

More importantly, Joskow-Kahn does not address the impact on prices and output of environmental limitations other than cumulative output restrictions. In particular we noted that the Delta Dispatch restrictions are in effect on the Mirant steam units other than Potrero 3 and Pittsburgh 7 specifically during the late May to early July period. Mirant can exceed the 86 degree limit on outlet water temperatures only when directed to do so by the ISO, either in response to a state of emergency or local area security (i.e., to operate at the level directed by the ISO under Mirant's RMR contract). It is noteworthy that a number of the moderately high priced June days such as June 12, 15, 16, 17, 21, 22, 23, and 30 did not have any hours of Stage 1 or higher level emergency. We have obtained the Mirant real-time dispatch logs for several of these days (June 15, 21, 22, 23 and 30). Although not all CAISO delta dispatch instructions are recorded in the logs, it can be seen in the logs that even during some of the high priced hours Mirant received permission to exceed the 86 degree limit only for its day-ahead RMR output and was not permitted to operate at full output in many high-priced hours. For example, despite real-time prices that reached $618.27 on June 22, Mirant appears to have been allowed to exceed the 86 degree limit only for its day-ahead RMR schedule.

Prices would indeed have been lower in June 2000 if Mirant did not have to obey the 86 degree limit, but that price impact reflects the environmental costs of operating at higher levels, not strategic withholding by generators.[49] Moreover, although little information appears to be publicly available on other environmental limits, as we pointed out in the earlier paper, Mirant was not the only generator subject to outlet water temperature restrictions.[50]

C. Reserves

A third major limitation of the Joskow-Kahn price simulations is a new one. In their prior simulations, they described their simulation methodology as dispatching generation resources to meet load and required reserves. We acknowledged in our April paper that this approach was superior to the BB&W/MSC[51] simulation approach which does not account for real-world

48 Harvey-Hogan (April), p. 20.

49 California PUC Decision No. 99-04-026, dated April 1, 1999. 1999 Cal. PUC Lexis 224.

50 Harvey-Hogan (April), p. 22.

51 See Severin Borenstein, James Bushnell and Frank Wolak, "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," August 2000 (hereafter BB&W) and Frank Wolak, Robert Nordhaus, and Carl Shapiro, "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Service Markets," September 6, 2000 (hereafter MSC).

reserve requirements. We noted, however, that the simplified approach to reserve modeling taken by Joskow and Kahn (i.e., treating reserves as load) could overstate market prices during non-shortage conditions.[52]

This methodology is radically changed, however, in simulations described in Joskow-Kahn (July). In the reply, Joskow-Kahn states that their new simulation takes account of only the 3 percent regulation up requirement and assumes that the CAISO would not need to meet WSCC criteria for minimum operating reserves.[53] The justification of this approach appears to rest on three grounds. First, that there was sufficient capacity available on unloaded hydro and GTs to provide the required reserves.[54] Second, that it is not necessary for the CAISO to maintain reserves in excess of its upward regulation margin. Third, that there was more than adequate capacity outside California to cover CAISO reserve requirements. We discuss this reasoning in detail below. The bottom line is that because of this assumption Joskow-Kahn simulated a market that is substantially different than that in which the CAISO operated. Market prices would have been lower in such a market, but the lower prices would have nothing to do with the conduct of generators. This is symptomatic of a problem in using the differences between simulated and real-world prices to draw conclusions about competition. Unless the simulation is very carefully calibrated against the real world, the differences between simulated and real-world prices will simply reflect the differences between the simulation and the real world, not differences in competitive conditions.[55]

Consider the first of the rationales Joskow-Kahn offer for the new approach, that there was sufficient capacity available on unloaded hydro and GTs to provide reserves, without backing down generation.[56] If this proposition could be shown to be factually correct, then it would indeed be the case that it would have been unnecessary to carry reserves on steam units and reserve prices would have been determined by the bids of the hydro suppliers and GT units. Joskow-Kahn does not establish the validity of this proposition, but merely assert it. We would be surprised if this were true. We know from the Mirant data that spinning and non-spinning

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[52] Harvey-Hogan (April), pp. 16-17.

[53] Joskow-Kahn (July), p. 7. They also state that "In our previous estimate, we followed Hildebrandt (2000) by adding 10% to the observed demand to satisfy AS requirements. Harvey and Hogan agree with our current view that this is too high (pp. 16-17)." What we actually said was that the Joskow-Kahn procedure:

> "should correct for the considerations discussed above [downward biases in other studies], permitting the analysis to identify capacity shortage hours and avoid the potential understatement of the market price of energy. In fact, this approach would have the potential to cause the simulation to overstate the competitive market price of energy because it would implicitly assume that all reserves are provided by infra-marginal generation which would also be an inaccurate assumption." Harvey-Hogan (April), p. 16.

[54] "We argue that unloaded hydro and extra-marginal peaking units are sufficient to meet the demand for other ancillary services." Joskow-Kahn (July), p. 7. "We argue instead that most AS demand can and should be provided by unloaded hydro capacity," p. 8

[55] It was explained to us long ago that direct comparisons between simulated and real-world prices would not be meaningful, even using complex simulation tools that take account of start-up costs, no-load costs, unit inflexibilities, and transmission constraints, and even when the world being simulated is one based on regulated cost-based offers.

[56] "There is enough hydro in the California ISO control area to provide most of these services, both in reality and in our modeling of the energy market." Joskow-Kahn (July), p. 8.

reserves were at times scheduled for the Mirant units, so these other resources must not always be sufficient even in NP-15. Moreover, we understand that the GT capacity was assumed to be available to be dispatched to meet load as well as provide reserves in the Joskow-Kahn model. This assumption in effect therefore potentially double-counts capacity, by assuming that it is available to generate energy and to provide reserves. To the extent that the simulation dispatches these units to meet load in the same hours in which Joskow-Kahn are assuming that these units were unloaded to provide reserves, the simulation double-counts capacity.

Joskow and Kahn's second rational for ignoring reserve requirements is perhaps related and appears to us to reflect a misunderstanding of reliability criteria. Joskow and Kahn state that:

> "Our analysis adopts a de-rating approach to forced outages, meaning that the capacity we assign to all units is reduced by the assumed forced outage rate. When we stack up resources against demand, we are assuming that these resources meet not only the final demand, but also the 'outage loads' associated with the expected level of forced outages, to the extent that outages occur on-the-day and are unknown ahead of time. These forced outages are the reason that AS reserves other than Regulation exist in the first place. In our procedure, we are already including the effect of these 'dispatched' AS reserves on energy prices. Therefore, we add only 3% to demand for Regulation Up. This is similar in spirit to the arguments made by Borenstein, Bushnell and Wolak (BBW) for adjusting demands to reflect Regulation Up but not other ancillary services in this type of supply curve analysis."[57]

These are not the WSCC rules followed by the CAISO. WSCC rules require maintenance of 5-7 percent operating reserves, and if the reserves are used to meet load, they require that reserves be restored within 60 minutes.[58] In other words, under the WSCC rules for the idealized case with 1000 small 1 MW plants and an average outage rate of 10 percent, the 900 MW of available plant would be sufficient to meet approximately 810 MW of load, leaving 3 percent needed for up regulation and 7 percent for operating reserves. The Joskow-Kahn assumption implies that these same plants could meet 870 MW of load, needing only the 3 percent up regulation. In the less than idealized case with large and heterogeneous plant sizes, the difference between the WSCC rule and the Joskow-Kahn assumption could be even greater.

Joskow and Kahn's simulations, in effect, assume that the reserves must be maintained as long as it is costless, but not if it becomes expensive. This assumption will also reduce simulated electricity prices as 5-7 percent less capacity would be needed to meet load. This reduction in electricity prices would be appealing but it would have nothing to do with competition or the exercise of market power, and the grid is not operated in this manner for reliability reasons. We previously explained at length why this same methodology as adopted by BB&W and MSC was at odds with the actual CAISO and WSCC reliability standards.[59] The system operator needs to

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[57] Joskow-Kahn (July), pp. 7-8.

[58] WSCC Minimum Operating Reliability Criteria, p. 3 "Restoration of operating reserves. After the occurrence of any event necessitating the use of operating reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes."

[59] See Harvey-Hogan (October), pp. 20-25.

have enough capacity to meet WSCC/NERC reliability targets after sustaining normal overnight unit losses and will take actions in real time (including expensive energy purchases) to restore reserves used to meet unexpected load or respond to contingencies.

We do not question that WSCC and CAISO prices would be lower if it were necessary only to maintain sufficient reserves to account for load uncertainty, rather than to maintain reliability after loss of generation units. Indeed, we discussed in prior papers how the WSCC and CAISO reliability standards contributed to high prices, but this impact is not a result of the exercise of market power.[60] Joskow and Kahn are at best simulating the operation of the grid under an alternative set of reliability criteria. This is an exercise in simulating prices in a more benign environment in which units politely suffer proportionate outages on each day and it is not necessary to maintain reserves to cover the loss of large generating units (because they are not lost all at once but only in proportion to their fixed outage rate). These modeling results may have little to say about the existence or exercise of market power, but merely demonstrate that electricity prices would be lower in this more benign environment.

Joskow-Kahn's third reason for ignoring reserve requirements is the view that there are sufficient resources available outside the CAISO control area to meet CAISO reserve requirements. In particular, they note that "There are adequate resources in the region to meet these reserve needs. Resources available for reserves outside of the ISO control area include BPA, LADWP's Castaic pumped storage plant (1,200 MW), and out-of-state gas turbines. Since BPA has adequate capacity (if not energy) for the winter in the Northwest, then it should have had at least several thousand MW in the Summer to sell as AS reserves."[61]

The actual supply of reserves from outside the CAISO control area has not matched this characterization. If Joskow-Kahn were correct regarding the available supply of reserves from outside the CAISO control area, the limited supply of external reserves in the real world would suggest that the source of the high prices in California was withholding of reserves by BPA and other external suppliers, rather than the claimed withholding by California generation owners. Alternatively, perhaps the problem is that the Joskow-Kahn assertion that BPA and others should have had several thousand MW of excess reserves in the summer is inaccurate and fails to reflect 1) the use of capacity to supply energy to California, 2) the need for BPA and other external control areas to maintain their own reserves at WSCC levels, 3) the impact of low hydro conditions on available capacity. In addition, the CAISO market design which treats spinning reserves as just another energy source to be dispatched to meet load, rather than as capacity reserved to respond to contingencies, may have driven energy limited resources out of the California reserve market during the summer of 2000, reducing the supply of reserves.

This is illustrative of the difficulties with such simulations that are at odds with the actual operation of the electric system and introduce substantial differences between the simulated world and the real world that are unrelated to competitive behavior of thermal generators within the CAISO control area. Furthermore, it is noteworthy that no sensitivity analyses were undertaken of these important assumptions regarding reserve requirements that in effect increase the

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60 Harvey-Hogan (October), pp.25-26.

61 Joskow-Kahn (July), p. 8.

capacity available to the CAISO in shortage hours by between 5 and 7 percent, or a few thousand MW.

D. Outages

We pointed out in our April paper that the Joskow-Kahn treatment of generation outages as proportional deratings of capacity, rather than probabilistic outages, would tend to reduce the number of shortage hours and thus understate the competitive level of prices.[62] In addition, because their methodology is based on assumed theoretical outage rates, rather than the actual outage rates during the summer of 2000, the analysis cannot distinguish between "high prices due to the exercise of market power or to higher than assumed outage rates."[63] We also questioned whether their simulation analysis included various thermal units owned by PG&E that were not available during all or part of the summer due to outages. Joskow-Kahn states that they responded to our comments about the Hunters Point units by deleting the unavailable PG&E units from the simulation[64] but they do not appear to have addressed the more fundamental observations regarding the outage methodology employed in their simulation.

The treatment of outages as proportional deratings of capacity would be particularly likely to understate the competitive price level in periods of capacity shortage, when the market is likely to be clearing on a highly convex portion of the industry inverse supply curve, as was often the case in June 2000. Moreover, the impact of modeling of generation outages as proportionate deratings is unambiguously to understate prices.[65] The impact of the second limitation is ambiguous, because it is not know exactly what "historical outage rates" were used in the simulation or what actual outages were in June. Joskow and Kahn refer to "HESI data on forced outage rates,"[66] but it is not entirely clear which particular outage data are referenced.[67] The Henwood data also do not account for the minor operational problems that reduce real-world output but may not amount to deratings. For example, the output of Mirant's Potrero 3 unit had to be reduced at times because the hydrogen used to cool the generator windings exceeded its temperature limit, requiring a reduction in output to reduce the load on the cooling system. This could happen as a result of a variety of problems in the cooling system, including warm bay water temperature and low tides. This is neither a forced outage nor a derating, but output is reduced.

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62 Harvey-Hogan (April), p. 34.

63 Harvey-Hogan (April), p. 33.

64 Joskow-Kahn (July), p. 11.

65 Paul L. Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Electricity Market During Summer 2000," March 2001 (hereafter Joskow-Kahn (March)) , p. 13, states this procedure is "common" and "reflects standard industry practice." Our experience is that the standard industry practice in real production simulations is to use some random process to generate a set of outages, which is why the commercial production simulations, such as GE-MAPS, have such a feature.

66 Joskow-Kahn (March), p. 13.

67 Joskow-Kahn (December) refers to the used of GADS equivalent forced outage data, which includes an adjustment for deratings.

Joskow-Kahn suggests that its analysis of withholding somehow addresses whether the output gap is due to withholdings or outages:

> "In the absence of unbiased review of generators' operating decisions, our withholding analysis is designed to answer an indirect question: Is the amount of unavailable generation in the California market consistent with the amount we would expect to be unavailable for engineering and other known reasons? Our measures of the output gap show that these amounts are not consistent. As we have calculated it, the output gap shows the amount of unavailable generation above and beyond what would be expected if historical outage rates held true."[68]

This does not appear to be the case, however. As far as we can detect, and based on our replication of the withholding analysis, Tables 8 and 15 in the recent paper include no allowance for "historical outage rates," and no allowance for total expected deratings, under generation and forced outages based on historical data for these or similar units at similar utilization rates.

E. Other Features of the Model

1. Load Shape

We pointed out in our April paper that the Joskow-Kahn use of hourly deciles could potentially materially affect the estimated prices. In Joskow-Kahn (July) the new simulation uses 100 hourly intervals as well as 10.[69] It can be seen in Table 3 of Joskow-Kahn (July) that more accurately representing demand and capturing the peaks increased the average price in the simulation by nearly $20 in June 2000 at a $10/lb. NOx price. This appears to us to be a material effect and suggests that factors affecting the relative tightness of the market in the high priced hours can have material impacts on estimated prices.[70] The sensitivity results suggest that taking account of reserve requirements would materially change the simulated results.

2. Hydro and Geothermal

We pointed out in April that it was uncertain whether the 8,000 MW of hydro power assumed to be available in Joskow and Kahn's original simulation analysis were actually available in every hour of the four high load deciles, i.e., 40 percent of all June hours.[71] In the new simulation, Joskow-Kahn raises the amount of hydro assumed to be available in the four high load deciles to 8,500 MW based on their conclusion that 8,500 MW of hydro generation appears to have been

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[68] Joskow-Kahn (July), p. 6.

[69] This is the only sensitivity analysis presented in the study.

[70] As discussed below in Section III.E.3 below, some of the results based on the 100 hourly intervals are a bit "odd," suggesting that either the methodology is not quite as described or that there is something wrong with the simulation results.

[71] Harvey-Hogan (April), pp. 40-42, and Joskow-Kahn (March), pp.11-12, 34.

available on August 16, 2000.[72] The figure on which they base their conclusion is calibrated only to 2,000 MW, and hydro is the difference between two other regions, so it is hard to be sure what quantities are being reported.[73] It is not clear to us whether the actual peak hydro available on August 16, or in June, was 8,500 MW, 8,000 MW or 7,500 MW. Were all 8,500 MW of hydro available in all of the high-load decile hours in June (i.e., 40 percent of all hours)? Nine hours during August 16 were in the top load decile for the month and 14 hours were in the top four deciles. The non-chronological Joskow–Kahn simulation apparently assumed that 8,500 MW of hydro and pumped storage was available in all 14 of these high load hours. In practice, prices exceeded $155 during all 14 of the high load hours on August 16, yet the CAISO data to which Joskow-Kahn refers do not indicate, to us, that 8,500 MW of hydro was available in these 14 hours. Our point remains valid. Because the Joskow-Kahn simulation is based on assumed hydro output levels, it cannot provide evidence that market power was exercised, but only establish that the price levels are consistent with either the exercise of market power, or lower levels of hydro output than assumed in the simulation. Moreover, since there is no reported sensitivity analysis regarding the assumed hydro outputs, it is not known how sensitive the simulated prices are to variations in the level of available hydro power.[74]

There is a similar ambiguity in the level of geothermal output assumed in the simulation. Joskow-Kahn based geothermal output on derated output capacities in their new simulation, but it is still not known how this output level compares to actual output.[75] As above, we cannot tell from the analysis whether the simulated price levels are lower than real-world price levels because of market power, or because of incorrect assumptions regarding the availability of geothermal energy. There is a similar ambiguity regarding the output of non-wind qualifying facility (QF) plants whose output also varies dramatically day to day and hour to hour.[76]

We observed in both of our prior papers discussing California price simulations that treating energy limited hydro and geothermal resources as price taking, rather than price making could cause the simulation to estimate lower prices than prevailed in the real world, even if no market power were exercised and all thermal generation had been bid into the market at competitive offer levels and was fully dispatched.[77] Joskow-Kahn did not change this feature of the model, nor offer any rationale for the approach taken.

3. Dispatch Instructions

We also pointed out in prior papers that simulations are not impacted by real-world constraints such as ramping limits or the chaos of real-time events.[78] In the real world, electricity demand

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72 Joskow-Kahn (July), p. 9. We have been unable to confirm with CAISO that only California hydro is included in the shaded region referred to by Joskow and Kahn.

73 California ISO CAISO 2001 Summer Assessment, Figure I-A, p. 9.

74 It is also not known if the simulation took account of the need for pumped storage to consume energy off-peak.

75 Joskow-Kahn (July), p. 10.

76 California ISO CAISO 2001 Summer Assessment, p. 13 , and Figure II C, p. 14

77 Harvey-Hogan (October), p. 34-35; Hogan-Harvey (April), pp. 22-23.

78 Harvey-Hogan (October), p. 28 and Harvey-Hogan (April) pp. 60-64.

must be met on a short-term basis and system operators sometimes must meet load with high cost quick ramping generation at the same time that generation with lower bids is on-line, and slowly increasing its output. In the Joskow-Kahn non-chronological simulation, there are no ramping constraints and load can always be met with the cheapest available generation. Similarly, even if start-up and minimum load costs are taken into account in the determination of equilibrium prices, real-world prices are also impacted by the fact that the actual demand level is often different from the anticipated level, which can require that load be met with much more expensive than anticipated generation. If the inverse supply curve is convex, these errors will not cancel out and demand uncertainty will raise the equilibrium level of real-time prices.[79]

Moreover, Joskow and Kahn simulate the least cost dispatch of generation to meet load, rather than attempting to simulate the operation of a market with the CAISO rules. Any market inefficiency arising from California market design would therefore be classified as arising from the exercise of market power.[80] None of these considerations are addressed in the Joskow and Kahn's reply.

4. Transmission Congestion

We also pointed out in our prior paper that the Joskow-Kahn simulation assumed the absence of transmission constraints within California.[81] The new Joskow-Kahn simulations apparently continue to assume the absence of transmission constraints, and the comparisons between the simulated and PX prices continue to be based on the "unconstrained" PX price. The "unconstrained" PX price is a price calculated as if there is no inter-zonal congestion, based upon actual bids, which may have been submitted in a period in which there was inter-zonal congestion. It is not the actual settlement price. The importance of this assumption is not clear. However, it may be of less importance given that we are unaware of arguments that transmission constraints played a prominent role in high priced hours in California in 2000.

5. Imports

We previously expressed concern with the ambiguously described methodology for accounting for imports in the BB&W, MSC and Joskow-Kahn simulation studies.[82] This methodology has not been clarified. Moreover, we have separately pointed out that the import elasticity assumed by Joskow-Kahn implies a much lower price response for import supply than internal CAISO supply.[83] Our concern regarding the validity of the import modeling is exacerbated by the new Joskow-Kahn results and discussion. It can be seen in Table 3 in Joskow-Kahn (July) (reproduced below as Table 22) that the simulated price for June 2000 declines with increases in

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79 Harvey-Hogan (April), p. 38-40.

80 Harvey-Hogan (October), pp. 29, 31-34, and Harvey-Hogan (April), pp. 35-36.

81 Harvey-Hogan (April), p. 23-25.

82 Harvey-Hogan (October), p. 35-36; Harvey-Hogan (April), p. 21, and Harvey-Hogan (November), pp. 18-25.

83 See Harvey-Hogan (November) pp. 20-25, particularly Table 7. The assumed import elasticity will not bias the simulation results as long as simulated imports equal actual imports at the real-world price. The assumed import elasticity can, however, magnify the impact of other elements of the simulation that overstate supply.

NOx allowance costs above $10/lb. We do not find this plausible and it is tempting to assume that is just a typographical error. The Joskow-Kahn paper, however, notes the anomaly and explains:

> "The June results for the 100 load point estimate are somewhat counter-intuitive, with benchmark prices first rising as RTC prices go from $0/lb to $10/lb and then falling as these prices go from $10/lb up to $30/lb. The lower price at high RTC costs is due to the import elasticity effect, which brings in more resources as in-state fossil costs increase. These increased imports then reduce the effect of the $750/MWh price cap as well."[84]

If the anomalous results in Joskow-Kahn Table 3 are attributable to the supply of imports, this implies that the import supply curve underlying these simulation results makes more import supplies available at lower prices ($71.65 for example) than at higher prices ($74.03). This suggests to us that there is something else driving this simulation beyond what has been discussed above.[85]

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[84] Joskow-Kahn (July), p. 12, footnote 26.

[85] An alternative explanation might be that the prices in Joskow-Kahn Table 3 (p.13) are averages calculated using a set of weights that depends on the amount of thermal generation dispatched. If this is the case, they are not comparable to the PX prices to which they have been compared. A paper released just as we were completing this paper, Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," December 21, 2001, p. 17 (hereafter Joskow-Kahn (December)), contains simulation estimates that have the expected pattern, i.e. they increase with NOx costs and differ materially from those in Joskow-Kahn (July). There is no explanation for these differences.

Table 22 Joskow-Kahn Table 3 Summary of Benchmark Costs						
		Average MC ($/MWh)				
Month	**Average PX Price ($/MWh)**	**$0/lb**	**$10/lb**	**$20/lb**	**$30/lb**	**$35/lb**
100 Load Points						
May	47.23	55.78	59.38	60.54	62.20	62.85
June	120.20	70.81	74.03	71.65	62.66	64.16
July	105.72	56.23	54.80	56.69	58.26	59.04
August	166.24	64.88	69.58	72.75	75.59	78.13
September	114.87	68.96	72.47	75.35	78.26	79.67
10 Load Points						
May	47.23	44.01	45.81	48.49	50.37	51.34
June	120.20	52.01	53.98	56.70	58.04	59.24
July	105.72	48.31	50.30	51.91	53.90	54.38
August	166.24	60.86	64.46	68.47	72.79	74.74
September	114.87	66.41	70.77	74.06	76.58	77.51
Source: Joskow-Kahn (July), Table 3, p. 13.						

This highlights a general problem with the simulation. The simulation shows that high prices in real system were due to market power, or due to the simulation using lower reserve requirements than applied in the real system, and/or ignoring start-up and no-load costs, and/or treating forced outages as proportional deratings and ignoring maintenance outages and other operating output limitations, and/or ignoring environmental output limitations, and/or overstating hydro, QF, geothermal and/or import supply. This simulation comparison is not easy to make, and the arguments above suggest that with the available data we cannot assume that these differences do not matter enough to change the conclusion about the size and scope of the exercise of market power.

F. Simulations

It is not an easy matter to design an efficient market for an electricity system. Furthermore, it is not a simple matter to simulate a market as complex as the electricity system, especially one with badly designed market institutions. Some of the problems with the Joskow-Kahn simulations are normally avoidable, some perhaps avoidable with effort, and some are intractable. However, our experience has been that even answering simpler questions than that posed by Joskow-Kahn can be difficult and resource intensive.

The failures to take account of start-up costs, minimum load costs, unit inflexibilities, and transmission constraints are correctable. Because these considerations have such powerful effects on simulation results, standard industry simulation tools used for many years have been designed to address these problems. GE MAPS, for example, is a widely used simulation tool in the electricity industry.[86] MAPS is a chronological model; that is, it looks at each hour in sequence, and runs a unit commitment evaluation on a weekly basis and then dispatches generation to meet load given this unit commitment. MAPS has a 3-pass option for the unit commitment step, which takes longer to run but provides a more consistent unit commitment. Because MAPS is chronological, it can and does take account of inflexibilities such as minimum run times in its unit commitment. MAPS also takes account of transmission constraints in dispatching generation to meet load and even calculates LMP prices for each location specified. Most standard industry modeling tools, including GE MAPS, are also designed to take account of reserve requirements, although it is sometimes not possible to model all of the locational requirements applying to each category of reserves. Data on non-dispatchable generation by QFs, wind and other generation sources can readily be built into the model and the other generation dispatched based on start-up, minimum load, and incremental energy bids.[87]

Most simulation studies, however, are intended to simulate future prices and compare alternative modeling scenarios, rather than to replicate past prices. This focus on the differences in modeled scenarios necessarily controls for the other common features of the model and isolates the causes of the differences. By contrast, it is quite another matter to extend this simulation approach to compare the model to the real data, especially under highly stressed conditions. One could in principle build in hourly load patterns and unit outages (if one had the outage data) reflecting the actual historical outages. Alternatively, as noted, one could build in outage factors reflecting forced outages and deratings and let MAPS apply these factors on a random basis.[88]

It would be much more difficult to build in environmental limits, even if one had all of the required data. Monthly and annual energy limits are hard to model, and capacities that change hour to hour during a day and depend on the status of the system (such as the Delta Dispatch) would not be easy to model in MAPS. One could perhaps indirectly model the Delta Dispatch by including the capacity with a very high dispatch price to signify that it would only become available for dispatch during shortages in which the price was high, but this would not capture all of the complexities of the Delta Dispatch.

Price setting hydro, pumped storage and geothermal generation could also be modeled in MAPS, but if they are modeled as price setting, they cannot be modeled as energy limited, and if they are

[86] GE MAPS can be licensed from GE Power Systems Economic Consulting or GE will run MAPS simulations for the user. GE Power Systems Economic Consulting has existing transmission databases for all U.S. regions, including the WSCC, as well as generation data bases, based on publicly available data. There also a variety of specialized MAPS databases for various regions that included various confidential data that are available for use by certain entities. Many MAPS users begin with the GE databases and modify them based on their information.

[87] The bid curves in MAPS may have up to seven price points.

[88] This approach has the property that the results depend on the actual pattern of random outages. We have found that even average annual prices can be noticeably affected by the pattern of outages. For this reason, one usually uses the same random number seed in comparative MAPS runs.

modeled as energy limited, they cannot be modeled as price setting and the outcome of the simulation might depend to a considerable degree on the assumed bidding strategy of these entities.

Further, the existing structure of most simulation tools is not well suited to modeling the chaos of real-time. While MAPS and other simulation tools include unit ramp rates, there are no surprises in the current structure. The load shape on which the unit commitment is based is also the load shape against which the units are dispatched. Moreover, random outages all occur prior to unit commitment in MAPS. This is similar to the way Joskow and Kahn have treated outages but with such an approach there is no analogue to the forced outage occurring in real-time.

While people have talked of modifying this structure, it has not to our knowledge actually been done, and entities using simulation tools make other ad hoc adjustments to the simulated prices to reflect these elements of the real world.

Finally, it should be noted that MAPS dispatches generation to meet load at least cost and calculates LMP prices based on this dispatch. This is not the structure of the CAISO markets. A simulation model would need to be modified to account for the dispatch of RMR generation by the CAISO and intra-zonal congestion management. Moreover, a substantial effort might be required to translate the dispatch of generation to meet load in MAPS and the resulting LMP prices, into a set of zonal prices as they would be calculated by the CAISO. It is not apparent that there is a straight-forward way in which to reflect the structure and inefficiency of California electricity markets in a simulation.

IV. WITHHOLDING ANALYSIS

A. Introduction

In our April paper we replicated the Joskow-Kahn withholding analysis and observed that much of the apparent output gap was attributable to several factors:

1. The hours selected by Joskow-Kahn for the “output gap” analysis included hours with high day-ahead prices but low real-time prices. Competitive firms should be expected to operate below capacity when real-time prices are low, regardless of day-ahead prices.[89]

2. The data on ancillary services utilized by Joskow and Kahn measured ancillary services procurement from internal CAISO generation, not requirements, and did not include all of the zones included in the withholding analysis. In addition, ancillary service procurement from internal CAISO generation was higher in the high real-time priced hours.[90]

3. Some of the hours with high day-ahead and real-time prices were immediately before or after low priced hours or dispatch intervals or even included low-priced dispatch intervals. Competitive firms that were following the CAISO’s dispatch instructions should be expected

[89] See Table 17 Harvey-Hogan (April).

[90] See Tables 18, 19 and 20 Harvey-Hogan (April).

to be ramping up or down during part of such hours, reducing their average output and giving rise to an apparent output gap.[91]

4. The Joskow-Kahn output gap calculation made no allowance for unit deratings, short of complete outages, or other temporary output limitations.[92]

5. The Joskow-Kahn output gap calculation made no allowance for environmental output limits such as the Delta Dispatch.[93]

6. The Joskow-Kahn output gap calculation was based on capacity measured by the highest output achieved by the unit for a single hour and did not necessarily measure capacity under normal conditions or for sustained operation.[94]

The revised Joskow-Kahn paper includes an improved calculation of ancillary service procurement, including procurement of ancillary services from generation from all of the relevant internal zones, but does not address any of the other limitations of their analysis that were described in our April paper. As a result, the paper provides limited information as to whether there has been strategic economic withholding of capacity. Indeed, several of the tables are based on premises regarding what constitutes strategic withholding of capacity that appear widely inconsistent with conventional views of competitive behavior.

B. Daylight Savings Time

Before turning to a detailed discussion of the new Joskow-Kahn analysis, it is necessary to point out and correct an error underlying the empirical analysis of the CEMS data in our prior paper and in both of the Joskow-Kahn papers. In our earlier paper we were able to largely replicate the Joskow-Kahn output gap calculations based on the CEMS data and the ISO and PX price data. In comparing the CEMS output data to actual Mirant generation data, however, we identified occasional relatively large discrepancies (in addition to the relatively consistent differences arising from the fact that the CEMS data reports gross generation and Mirant's metered output reports net generation).[95] The pattern in the discrepancies enabled us to identify the source of the problem as that the CEMS data are recorded based on standard time, while the Mirant output data and ISO and PX price data for June 2000 are recorded on a daylight savings time basis.[96] As

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91 See Table 21 and 22 Harvey-Hogan (April).

92 Harvey-Hogan (April), pp. 51-52.

93 Harvey-Hogan (April), pp. 51-52.

94 Harvey-Hogan (April), pp. 64-66.

95 That is, the CEMS data include as output electricity that was consumed at the plant and thus not available for sale.

96 We have confirmed with Mirant that it reports its CEMS data on a standard basis with no adjustment for daylight savings time. The EPA website also indicates that the data are to be reported based on standard time. "Revised EDR Version 2.1 Reporting Instructions," Clean Air Markets Division, U.S. EPA, January 24, 2001. www.epa.gov/airmarkets/reporting/edr21/index.html. Finally, we verified that all of the generators included in the Joskow-Kahn analysis reported 720 hours of CEMS data for April 2000, while there are only 719 hours of ISO and PX price data.

a result of this difference, both we and they have not appropriately matched price and output data in the prior analyses. While this does not make much difference in practice during long periods of sustained high prices, it can produce large discrepancies during hours in which prices are rising or falling.

To avoid confusion and correct this error, we have recalculated the tables in our earlier paper based on an appropriate matching of prices and output. Table 23 below reproduces Table 14 in our earlier paper reporting the output gap for the hours with high prices in the day-ahead PX market. It can be seen that the correction does not greatly change the calculation of the average output gap.

Table 23
Output Gap, Not Adjusted for Outages
June 2000, PX Price > $120/MWh

Owner	Maximum Output (A)	Joskow-Kahn Calculation: Mean Output (B)	Joskow-Kahn Calculation: Output Gap (C)	Replication: Mean Output (D)	Replication: Output Gap (E)
NP-15, SF and Z-26					
Duke	2,563	2,422	141	2,426	137
Southern	2,932	2,090	842	2,110	822
Total	5,495	4,512	983	4,536	959
AS Procurement (excluding replacement)					1107
AS Procurement (including replacement)			1510		1610
SF and Humboldt					
PG&E	N/A	N/A	N/A	95	184
SP-15					
AES	3,681	2,542	1,139	2,561	1,120
Duke	733	643	90	652	81
Dynegy	2,000	1,014	986	1,060	940
Reliant	3,487	2,351	1,136	2,380	1,107
Total	9,901	6,550	3,351	6,653	3,248
AS Procurement (excluding replacement)					1048
AS Procurement (including replacement)			1672		1678

Sources:
(A) – (C): Joskow-Kahn, Table 8.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Col. (A) – Col. (D). Ancillary Service Procurement, Harvey-Hogan (April), Table 8.

Table 24 below reproduces Table 15 in our earlier paper, reporting the calculated output gap for the subset of the hours with both high day-ahead prices and real-time prices. Once again, the calculated output gap is not greatly different than that in our earlier paper.

Table 24
Output Gap (MW), Not Adjusted for Outages
June 2000

Owner	Maximum Output (A)	Joskow-Kahn PX Price > $120/MWh		PX and Real-Time Price > $120/MWh	
		Mean Output (B)	Output Gap (C)	Mean Output (D)	Output Gap (E)
NP-15, SF and Z-26					
Duke	2,563	2,422	141	2,414	149
Southern	2,932	2,090	842	2,313	619
Total	5,495	4,512	983	4,727	768
AS Procurement (excluding replacement)					1,125
AS Procurement (including replacement)			1,510		1,746
SF and Humboldt					
PG&E	279	93	186	102	177
SP-15					
AES	3,681	2,542	1,139	2,606	1,075
Duke	733	643	90	672	61
Dynegy	2,000	1,014	986	1,184	816
Reliant	3,487	2,351	1,136	2,451	1,036
Total	9,901	6,550	3,351	6,913	2,988
AS Procurement (excluding replacement)					1,100
AS Procurement (including replacement)			1,672		1,945

Sources:

(A) - (C): Joskow-Kahn, Table 8.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Col. (A) – Col. (D). Ancillary Service Procurement, Harvey-Hogan (April), Table 19.

Table 25 reproduces Table 17 in our earlier paper reporting the output gap calculated for on-line units (Joskow-Kahn Test 1) for the hours with high both high day-ahead prices and real-time prices. Once again, the correctly calculated output gap is slightly smaller than, but not greatly different from the figures reported in the earlier paper.

Table 25 Output Gap (MW), Adjusted for Outages (Test 1) June 2000						
	Joskow-Kahn PX Price > $120/MWh			PX and Real-Time Price > $120/MWh		
Owner	**Maximum Output (A)**	**Mean Output (B)**	**Output Gap (C)**	**Maximum Output (D)**	**Mean Output (E)**	**Output Gap (F)**
NP-15, SF and Z-26						
Duke	2,541	2,422	119	2,528	2,414	114
Southern	2,740	2,090	650	2,788	2,313	475
Total	5,281	4,512	769	5,316	4,727	589
AS Procurement (excluding replacement)						1125
AS Procurement (including replacement)			1510			1746
SF and Humboldt						
PG&E	NA	NA	NA	109	102	7
SP-15						
AES	2,945	2,542	403	2,942	2,606	336
Duke	723	643	80	722	672	50
Dynegy	1,611	1,014	597	1,592	1,184	408
Reliant	3,225	2,351	874	3,243	2,451	792
Total	8,504	6,550	1,954	8,499	6,913	1,586
AS Procurement (excluding replacement)						1,100
AS Procurement (including replacement)			1,672			1,945

Sources:
(A) - (C): Joskow-Kahn, Table10, as corrected in Harvey-Hogan (April), Table 16.
(D) – (E): CEMS data, adjusted for Daylight Savings Time.
(F): (D) – (E) Ancillary Service Procurement, Harvey-Hogan (April), Table 18.

Finally, Table 26 reproduces Table 21 in our earlier paper, reporting the calculated output gap for on-line units (Joskow-Kahn Test 1) for the non-ramping hours with high real-time prices. The correctly calculated output gap is slightly larger in NP-15 and slightly smaller in SP-15 but basically unchanged overall.

Table 26 Output Gap (MW), Adjusted for Outages and Ramping June 2000						
	High-Priced RT Hours			**High-Priced Non-Ramping RT Hours**		
Owner	**Maximum Output (A)**	**Mean Output (B)**	**Output Gap (C)**	**Maximum Output (D)**	**Mean Output (E)**	**Output Gap (F)**
NP-15, SF and Z-26						
Duke	2,528	2,414	114	2,537	2,428	109
Southern	2,788	2,313	475	2,812	2,478	334
Total North	5,316	4,727	589	5,349	4,906	443
AS Procurement (excluding replacement)			1,125			1,038
AS Procurement (including replacement)			1,746			1,796
SF and Humboldt						
PG&E	109	102	7	109	105	4
SP-15						
AES	2,942	2,606	336	2,977	2,660	317
Duke	722	672	50	725	693	32
Dynegy	1,592	1,184	408	1,598	1,273	325
Reliant	3,243	2,451	792	3,295	2,550	745
Total SP-15	8,499	6,913	1,586	8,595	7,176	1,419
AS Procurement (excluding replacement)			1,100			1,178
AS Procurement (including replacement)			1,945			2,273

Sources:
(A) – (C) Table 25.
(D) – (E) CEMS data, adjusted for Daylight Savings Time; note Williams units.
(F) = (D) – (E) Ancillary Service Procurement, Harvey-Hogan (April), Table 22.

Correcting the calculation of the output gap to reflect daylight savings time does not therefore fundamentally change the conclusion in our earlier paper that one cannot infer based on the CEMS data whether economic withholding occurred. The reported procurement of ancillary services is of the same magnitude or larger than the estimate of the output gap. Hence, it is possible that virtually all of the capacity not producing energy was producing required ancillary services.

C. Output Gaps on High-Priced Days

We now turn to the new analysis of the output gap offered by Joskow-Kahn. We begin with a consideration of Joskow-Kahn's Table 15, which reports the output gap during five high priced days during June 2000. Joskow-Kahn reasonably concludes that on these five high priced days "demand was so high that all available capacity should have been running."[97] For the selected hours on each of these days they calculate an output gap that greatly exceeds their calculation of undispatched ancillary services from generation. The output gap calculation, however, has the same limitations as the output gap calculations in their earlier paper, and if a few of these limitations are taken into account in the analysis, the output gap is substantially reduced. In particular, the output gap in Table 15 is calculated for hours in which real-time prices were low as well as high, but low output in low-priced hours does not indicate economic withholding. Second, the output gap calculated in Table 15 includes the capacity of off-line units. While we would expect "all available capacity to be running" in the high priced hours on these days, units that are not available due to forced outages would not be running but are not necessarily engaged in economic withholding. Third, even if the output gap calculation is restricted to hours with high real-time prices, the calculation includes ramping hours in which output may be less than capacity because the unit is ramping from a low output level to a high output level over some period of time. Fourth, the analysis does not account for capacity of on-line units that is not available due to derating of capacity (i.e., partial outages). Fifth, the analysis does not account for capacity that is not eligible for dispatch due to environmental limits. Sixth, the analysis of GT capacity makes no allowance for the impact of temperature on GT output. Each of these limitations is discussed in greater detail below.

Before turning to these points, we first note that correcting the Joskow-Kahn calculations to correct for Daylight Savings Time has a very minor impact on the overall output gap, as shown in Table 27.

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97 Joskow-Kahn (July), p. 26.

Table 27
Joskow-Kahn Table 15. Daily Output Gap Calculations
High Priced PX or RT Hours

	Joskow-Kahn			Replication		
Date	**Mean Output (A)**	**Klein Capacity (B)**	**Output Gap (C)**	**Mean Output (D)**	**Klein Capacity (E)**	**Output Gap (F)**
6-14-00	6,102	9,670	3,568	6,252	9,751	3,499
6-15-00	5,994	9,670	3,676	6,099	9,751	3,652
6-26-00	7,107	9,670	2,563	7,225	9,751	2,526
6-27-00	6,518	9,670	3,152	6,597	9,751	3,154
6-28-00	6,330	9,670	3,340	6,358	9,751	3,393
Average	6,410	9,670	3,260	6,506	9,751	3,245

Sources:
(A) – (C): Joskow-Kahn (July), Table 15.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Klein (April 1998).
(F): (E)-(D).

It should be noted, however, that we cannot exactly reproduce the Joskow-Kahn figure for capacity and our analysis is based on the higher figure we have calculated, which, other things equal, would tend to increase the calculated output gap.

It is important to recognize that the output gap calculated in Joskow-Kahn Table 15 is the difference between capacity and output in any hour in which *either* the day-ahead price or real-time price exceeded \$120.[98] This means that Joskow and Kahn consider it to be evidence of the exercise of market power if a generator does not operate at full capacity and the day-ahead price exceeded \$120, even if the real-time price were zero. In our view, this is an oversight. Moreover, this combination of high day-ahead prices and low real-time prices is not hypothetical. Some of the hours included in Joskow and Kahn's calculation of "economic withholding" in Table 15 include hour ending 9 on June 15, during which the SP-15 real-time price was -\$7 (with an "output gap" of 4,836 MW), and hour ending 23 on June 15 during which the SP-15 real-time price was \$2.20 (with an "output gap" of 5,660 MW). Not surprisingly, these output gaps are thousands of MW larger than the average gaps in Joskow-Kahn Table 15 and serve to pull the average up. While high day-ahead prices would affect the willingness of a competitive firm to commit a unit, and thus the likelihood that a unit would be operating at some level in real time, day-ahead prices have no bearing on whether the unit would operate above

98 "Table 15 shows the gap calculations for the high-priced hours (day ahead or real time) for these five days." Joskow-Kahn (July), p. 26.

minimum load in real-time. The real-time output of a competitive firm should be governed by real-time prices. Table 15 in Joskow-Kahn is therefore premised on a definition of output gap and economic withholding that is not based on competitive behavior and appears to ignore the basic profit maximizing choice.

The only rationale we have been able to identify in the Joskow-Kahn paper for this view of withholding is the statement that:

> "Harvey & Hogan claim that the only relevant hours to consider are those when *both* day ahead and real time prices are above a threshold level.[99] Since generators can make both start-up and dispatch decisions up until real time, we think that there are equally compelling arguments for examining hours in which only the real time price exceeds some threshold or – if at least some irreversible operational decisions are made day ahead – hours in which either the day ahead or the real time price is above some threshold. In what follows, we examine hours which meet this second criterion."[100]

This statement reflects confused reasoning. The irreversible operational decision made day ahead is whether to operate at all. There is no irreversible day-ahead decision to operate at full capacity even if prices are low, zero or even negative in real time. A competitive firm will be unable to respond to high prices in real time if day-ahead prices were low and its unit is off-line in real time, but even in the California markets it will be able to reduce output in real time if real-time prices are low. In our view, the only implication of high day-ahead prices for the real-time output of competitive firms is that more capacity would likely be on-line than if day-ahead prices were low. The real-time output of competitive firms would be governed by the level of real-time prices. This apparently reflects a very fundamental difference between us and Joskow-Kahn with respect to our view of competitive behavior, as they appear to argue that the real-time output decisions of competitive firms should be based on day-ahead prices, without regard to real-time prices.

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99 This claim does not cite any statement in our April paper and its not accurate. Instead, we stated

> "Importantly, Joskow and Kahn select the hours they analyze based on high day-ahead PX prices, but then test for withholding based on real-time output. This tends to bias the study towards finding evidence of withholding, even if none existed because the real-time output of a competitive firm depends on real-time prices, not just day-ahead prices. Even if output is sold forward at day-ahead prices, this is only a financial commitment. The ultimate opportunity cost for real-time production is the real-time price that would apply to any differences between day-ahead schedules and actual production.
>
> In particular, the selection of high-priced hours restricts attention to the supply region where Joskow and Kahn presume that competitively offered plants would all be at their maximum output. Higher real-time prices should not produce higher output, but lower real-time prices could result in lower output. The effects do not average out. Therefore, with any significant volatility in real-time prices relative to day-ahead prices, this asymmetry would tend to overstate the implied withholding of supply."

Harvey-Hogan (April), p. 44. We took as given the hours that Joskow and Kahn identified for analysis and observed that it does not make economic sense to include in a economic withholding analysis the output gap during hours with low real-time prices.

100 Joskow-Kahn (July), p. 20.

We have recalculated in Table 28 the output gap for the steam units (only) in Joskow-Kahn Table 15 restricting the analysis to the hours on these days during which the real-time price exceeded $120. This recalculation excludes from the calculated output gap capacity that was likely not used to produce electricity for the simple reason that the real-time price was low. It can be seen that real-time output averages about 200 MW higher on an hourly basis during the hours in which real-time prices were high, with larger and smaller differences from hour to hour and day-to-day.

Table 28
Joskow-Kahn Table 15. Daily Output Gap Calculations

	High Priced PX or RT Hours			High Priced RT Hours		
Date	**Joskow-Kahn Calc. Mean Output (A)**	**Joskow-Kahn Capacity (B)**	**Joskow-Kahn Calc. Gap (C)**	**Mean Output (D)**	**Klein Capacity (E)**	**Output Gap (F)**
6-14-00	6,102	9,670	3,568	6,351	9,751	3,400
6-15-00	5,994	9,670	3,676	6,544	9,751	3,207
6-26-00	7,107	9,670	2,563	7,196	9,751	2,555
6-27-00	6,518	9,670	3,152	6,597	9,751	3,154
6-28-00	6,330	9,670	3,340	6,363	9,751	3,388
Average	6,410	9,670	3,260	6,610	9,751	3,141

Sources:
(A) – (C): Joskow-Kahn (July), Table 15.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Klein (April 1998).
(F): (E)-(D).

As before, we have tested whether the output gap is statistically different in the hours in which day-ahead prices are high but real-time prices are low from the output gap in the hours in which real-time prices are high. The output gap is 766 MW smaller in the hours with high real-time prices than in the hours with low real-time prices and the difference is statistically significantly different from zero at the 90 percent level.

A second limitation of the calculation of the output gap in Table 15 is that it includes the capacity of off-line steam units. While we agree that it is unlikely that many units were off-line on these hot weather and high priced days due to economics (i.e., start-up and no-load costs), units could also have been off-line on these days due to forced outages, or in order to make repairs, rather than economic withholding. As Joskow and Kahn note in their reply, if the capacity of offline units is excluded, the size of the calculated output gap is further reduced.[101] In fact, it can be seen in Table 29 below that if the output gap is calculated for on line units based on real-time prices, the "output gap" is substantially reduced.

Table 29
Joskow-Kahn Table 15. Outage Adjusted Output Gap Calculations

	High Priced PX or RT Hours			High Priced RT Hours		
	Joskow-Kahn			Outage Adjusted		
Date	**Mean Output (A)**	**Klein Capacity (B)**	**Output Gap (C)**	**Mean Output (D)**	**Klein Capacity (E)**	**Output Gap (F)**
6-14-00	6,102	9,670	3,568	6,351	8,608	2,257
6-15-00	5,994	9,670	3,676	6,544	7,841	1,297
6-26-00	7,107	9,670	2,563	7,196	8,499	1,304
6-27-00	6,518	9,670	3,152	6,597	8,327	1,730
6-28-00	6,330	9,670	3,340	6,363	8,419	2,056
Average	6,410	9,670	3,260	6,610	8,339	1,729

Sources:
(A) – (C): Joskow-Kahn (July), Table 15.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Klein (April 1998).
(F): (E)-(D).

We also pointed out in our April paper that competitive units would produce at an average hourly rate that is less than their capacity during hours with high real-time prices if the units were ramping up their output during the hour as a result of low prices at the beginning of the hour or ramping down their output as a result of low prices at the end of the hour. Moreover, the statistical analysis indicated that one could reject at high confidence levels the proposition that the output gap for the ramping and non-ramping hours was drawn from the same distribution. It does not appear to us that Joskow-Kahn anywhere addresses this issue in the reply. The point is simply ignored. Moreover, this consideration is relevant even on the five high priced days they analyze in Table 15, because the real-time prices were in fact not uniformly high on these days and there were a number of significant swings in real-time prices, particularly on June 14 and 15. For example, the incremental price was zero in intervals 1-4 of hour ending 9 on June 14, just before the price spiked to $120 in hour ending 10. Similarly, the incremental price was zero in each interval of hour ending 23 on June 14, just before the price spiked to as high as $179 during

[101] Joskow-Kahn (July), p. 27.

hour ending 24. Indeed, the incremental price was zero in the first interval of hour ending 20 (as well as in the last 4 intervals of hour ending 19) on June 15, despite the high average price for the hour.

When large price swings like this occur, some generators may not be able to increase their output as rapidly as the price increases, giving rise to an apparent output gap that merely reflects ramp limits. Moreover, when price first falls dramatically, then rises dramatically, the output response may be further delayed, because some units may have begun to ramp their output down and, once started, it may take a while to reverse direction and increase output. This would also show up as an output gap. These physical limitations could be exacerbated by CAISO market and settlement rules. In particular, hourly settlements would tend to cause market participants to adjust their output in response to the average hourly price rather than to respond to dispatch instructions. Low prices at the beginning of an hour could deter market participants from responding to high prices at the end of the hour (because the average hourly price would be low), potentially leaving the CAISO very short at the beginning of the next hour. This again is not the result of the exercise of market power, but merely a consequence of market and settlement rules.

Overall, if hours in which the preceding or following hour had an overall price less than $120 are excluded from Table 15, the output gap falls as shown in Table 30. The output gap is 1,493 MW smaller in the non-ramping hours than in the ramping hours and the difference is statistically significantly different from zero at the 99.9 percent confidence level.

Table 30 Joskow-Kahn Table 15. Daily Output Gap Calculations							
		High Priced PX or RT Hours			High Priced Non-Ramping RT Hours		
		Joskow-Kahn			Outage Adjusted		
Date	**Unit Category**	**Mean Output (A)**	**Klein Capacity (B)**	**Output Gap (C)**	**Mean Output (D)**	**Klein Capacity (E)**	**Output Gap (F)**
6-14-00	Big GTs	202	476	274	N/A	N/A	N/A
	Unadjusted CEMS	6,102	9,670	3,568	6,932	8,650	1,718
	Long Beach	291	560	269	N/A	N/A	N/A
	Small GTs	102	271	169	N/A	N/A	N/A
	Total	6,697	10,977	4,280	N/A	N/A	N/A
Total AS Procurement (excl. replacement)							1,519
Undispatched AS Procurement				1460			2,012
6-15-00	Big GTs	63	476	413	N/A	N/A	N/A
	Unadjusted CEMS	5,994	9,670	3,676	6,771	7,871	1,100
	Long Beach	413	560	147	N/A	N/A	N/A
	Small GTs	54	271	217	N/A	N/A	N/A
	Total	6,524	10,977	4,453	N/A	N/A	N/A
Total AS Procurement (excl. replacement)							1,015
Undispatched AS Procurement				1800			1,353
6-26-00	Big GTs	174	476	302	N/A	N/A	N/A
	Unadjusted CEMS	7,107	9,670	2,563	7,664	8,573	909
	Long Beach	90	560	470	N/A	N/A	N/A
	Small GTs	131	271	140	N/A	N/A	N/A
	Total	7,502	10,977	3,475	N/A	N/A	N/A
Total AS Procurement (excl. replacement)							1,107
Undispatched AS Procurement				1041			1,199
6-27-00	Big GTs	293	476	183	N/A	N/A	N/A
	Unadjusted CEMS	6,518	9,670	3,152	7,383	8,413	1,030
	Long Beach	311	560	249	N/A	N/A	N/A
	Small GTs	113	271	158	N/A	N/A	N/A
	Total	7,235	10,977	3,742	N/A	N/A	N/A
Total AS Procurement (excl. replacement)							1,229
Undispatched AS Procurement				1,321			1,599
6-28-00	Big GTs	172	476	304	N/A	N/A	N/A
	Unadjusted CEMS	6,330	9,670	3,340	6,943	8,448	1,505
	Long Beach	276	560	284	N/A	N/A	N/A
	Small GTs	71	271	200	N/A	N/A	N/A
	Total	6,849	10,977	4,128	N/A	N/A	N/A
Total AS Procurement (excl. replacement)							1,023
Undispatched AS Procurement				1195			1,470

Sources:
(A) – (C): Joskow-Kahn, Table 15.
(D): CEMS data, adjusted for Daylight Savings Time.
(E): Klein (April 1998).
(F): (E)-(D). Ancillary Service Data from CAISO website.

If the cause of high prices were economic withholding of output, this withholding should show up in periods of sustained high prices. If there is no apparent economic withholding during periods of sustained high prices, then there is little basis for assuming that any output gap during ramping hours reflects economic withholding rather than ramping constraints.

Finally, it appears that Joskow and Kahn's use of BEEP stack dispatch data to draw inferences about the amount of generation procured to provide ancillary services that was dispatched provides useful information and we have adopted it in Table 30.[102] Nevertheless, a few qualifications ought to be attached to these data. First, the BEEP dispatch was not always operational in June 2000 and instructions were at times relayed by phone. It is not clear that the posted BEEP data are accurate for all of these hours. Second, we have identified hours in which units supposedly providing spinning or non-spinning reserves were generating energy rather than providing reserves, the BEEP was operating and the dispatch of these units is not reported in the published BEEP dispatch data. One circumstance that can produce this outcome would be an RMR unit that is instructed to increase output in real time and chooses to be paid the market rather than the contract price. The unit's real-time output in excess of day-ahead schedules would apparently be treated by the CAISO as uninstructed output and no BEEP instruction would be recorded. A RMR unit could apparently be instructed to go to the top in the morning, run at capacity all day, and never show up as dispatched in the BEEP stack.[103] While the Joskow-Kahn approach is useful, we should all keep in mind that it provides only an approximate measure of the undispatched capacity providing reserves.

The output gap on the steam units portrayed in Table 30 is much reduced from that portrayed in Joskow-Kahn Table 15 and is less than estimated undispatched ancillary services capacity on the 14th, 15th, 26th and 27th. Joskow-Kahn provides calculations indicating a further output gap on units not included in the CEMS data, as shown on the left hand side of Table 30. We have not attempted to replicate those calculations. However, the output gap Joskow-Kahn calculates for units not included in the CEMS data includes the capacity of GTs that were not available to provide reserves or capacity due to outages; does not account for GT capacity deratings due to high ambient temperatures; or other operating problems and is calculated for hours with low real-time prices as well as high real-time prices. Similarly, the output gap calculated for units in the CEMS database does not account for deratings of steam unit capacity due to operational problems or environmental restrictions; may not be based on sustainable capacities, and includes ramp-constrained capacity of steam units coming on-line.[104]

We lack the data necessary to directly resolve all of these ambiguities. It is, however, possible to gain considerable insight into the significance of economic withholding and the reliability of the

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[102] Joskow and Kahn take us to task because "Harvey & Hogan appear to accept that Replacement Reserve was dispatched, but continue the unfortunate practice of focusing mainly on the total AS in each zone and fail to include dispatched AS capacity in their withholding analysis." p. 21. We merely reproduced their ancillary service calculations and corrected them to include data for zones omitted from the Joskow-Kahn calculation.

[103] In this circumstance, the measure Joskow-Kahn (July) introduce of capacity providing ancillary services would be conservative.

[104] For example, El Segundo 1 and 2 came on-line during the day on June 27, and 82 MW of the overall output gap is due to those units. El Segundo 3 and Redondo 5 came on line during the day on June 28 and accounted for 147 MW of the overall output gap. Alta 3-1 and 3-2 came on-line during the day on June 26. South Bay 4 also came on-line during the day on June 28 but its capacity is so understated by Klein that its negative output gap after it comes on-line more than compensates for the positive output gap as the unit is coming on-line.

Joskow-Kahn simulation methodology by approaching the question from another direction. A number of the hours on these days were hours of declared stage 1 or higher emergency. This is significant in assessing the supply and demand calculations because the declaration of a stage 1 emergency implies that the CAISO has inadequate capacity to meet its reserve requirements, at any price. Thus, although Joskow and Kahn have attempted to demonstrate through an indirect analysis that the available capacity exceeded ancillary service requirements, we know directly from other CAISO data there was inadequate capacity available during many of the high priced real-time hours, regardless of the results of Joskow and Kahn's hypothetical analysis. Table 31 portrays the output gap for the high priced non-ramping hours on these days in total, broken down by emergency and non-emergency hours, as well as ancillary service requirements and undispatched capacity calculated using the Joskow and Kahn methodology.

Table 31 suggests several conclusions. First, the rather large average output gap relative to calculated ancillary service requirements in Table 31 during emergency hours in which it is known that there was in fact a capacity shortage in real-time, suggests that the limitations we have previously noted regarding some of the data used in the Joskow-Kahn output gap analysis (i.e., overstated maximum capacities, no account taken of deratings and operating problems, no account taken of environmental output restrictions)[105] are material in practice.

[105] Harvey-Hogan (April), pp. 51-52, 64-66.

Table 31 Capacity and Output During Non-Ramping Emergency and Non-Emergency Hours									
					AS Procurement				
Date	CAISO State (A)	On-Line Capacity (MW) (B)	Mean Output (MW) (C)	Output Gap (MW) (D)	Incl. Replace-ment (MW) (E)	Excl. Replace-ment (MW) (F)	Un-Dispatched AS (MW) (G)	SP-15 Time Average Price ($/MW) (H)	Hours (I)
6/14	Emergency	8,650	6,884	1,767	2,799	1,513	1,923	$668.64	8
	Non-Emergency	8,650	7,061	1,589	3,100	1,536	2,250	$585.72	3
6/15	Emergency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Non-Emergency	7,871	6,771	1,100	2,328	1,015	1,353	$602.53	4
6/26	Emergency	8,590	8,050	540	2,476	995	1,310	$750.00	3
	Non-Emergency	8,560	7,375	1,185	1,665	1,191	1,117	$547.34	4
6/27	Emergency	8,413	7,383	1,030	2,172	1,229	1,599	$699.48	11
	Non-Emergency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6/28	Emergency	8,486	7,031	1,455	2,176	1,176	1,762	$674.40	8
	Non-Emergency	8,373	6,768	1,605	935	720	889	$499.72	4

Sources:
(A): Emergency hour designation from CAISO website.
(B): Klein (April 1998).
(B)-(D): CEMS data, adjusted for Daylight Savings Time.
(E)-(G): Ancillary service data from CAISO website.
(H): Price data from CAISO website.

Second, three of the days (June 14, 26 and 28) have high priced non-ramping hours that fall into both categories, emergency and non-emergency. The non-emergency hours were not hours of capacity shortage,[106] thus the high prices during these hours could, in principle, be attributable to economic withholding rather than shortage.

Third, the average output gap calculated in this manner for the non-emergency hours is not substantially different than the gap during the emergency hours during which it is known that there was a shortage. Moreover, the average output gap during emergency hours reflects the impact of hours of rather extreme shortage. It can be seen in Table 32 that the range of output gap levels during non-emergency high-priced hours is little different than the level that would trigger an emergency, suggesting that these are also hours of short supply, rather than the high prices being the product of economic withholding during non-shortage hours. Thus, the output gap calculated using the Joskow-Kahn methodology ranged from 1,397 to 2,434 during the emergency hours on June 14, with gaps exceeding 1,683 in four hours and exceeding 1,625 in five of the eight hours. The calculated gap ranged from 1,459 to 1,683 in the non-emergency hours with gaps of 1,625 or less in two of the three hours. This does not suggest a major difference in the degree of supply tightness between the emergency and non-emergency hours.

[106] Although, it should be kept in mind they may have been expected to have been hours of shortage, at least by some market participants, just as some of the actual shortage hours may not have been anticipated, at least by all market participants.

Table 32
Capacity and Output During Non-Ramping Emergency and Non-Emergency Hours

Date	Hour Ending (A)	On-Line Capacity (B)	Mean Output (C)	Output Gap (B-C)	Incl. Replacement (D)	Excl. Replacement (E)	Undispatched AS (F)	SP-15 Real-Time Avg. Price (G)
CAISO Emergency Hours								
14 June	14	8,650.00	6,814.00	1,836.00	3,353.95	1,713.10	2,040.70	$750.00
	15	8,650.00	6,992.00	1,658.00	3,376.59	1,669.71	1,658.53	750.00
	16	8,650.00	7,041.00	1,609.00	3,341.83	1,531.32	1,549.15	750.00
	17	8,650.00	7,224.00	1,426.00	3,367.81	1,506.76	3,188.42	750.00
	18	8,650.00	7,253.00	1,397.00	3,183.72	1,403.32	1,704.91	750.00
	19	8,650.00	6,958.00	1,692.00	2,940.06	1,766.99	2,580.26	491.09
	20	8,650.00	6,570.00	2,080.00	1,993.91	1,786.91	1,934.21	637.47
	21	8,650.00	6,216.00	2,434.00	830.82	723.31	726.51	470.56
15 June	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26 June	16	8,590.00	7,997.00	593.00	2,488.91	1,000.80	1,020.50	750.00
	17	8,590.00	8,223.00	367.00	2,551.52	1,016.80	941.87	750.00
	18	8,590.00	7,931.00	659.00	2,388.28	967.76	1,966.84	750.00
27 June	11	8,014.00	6,987.00	1,027.00	2,133.61	2,065.01	1,686.69	337.04
	12	8,255.00	7,320.00	935.00	1,383.68	1,330.08	939.07	679.83
	13	8,255.00	7,050.00	1,205.00	2,240.93	1,140.76	1,662.20	750.00
	14	8,435.00	7,303.00	1,132.00	2,309.41	1,320.10	1,663.82	750.00
	15	8,435.00	7,743.00	692.00	2,223.71	1,147.41	1,403.83	750.00
	16	8,435.00	7,957.00	478.00	2,286.43	1,191.83	1,447.75	750.00
	17	8,435.00	7,914.00	521.00	2,632.91	1,378.31	1,779.63	750.00
	18	8,435.00	7,510.00	925.00	2,694.75	1,095.66	2,090.01	750.00
	19	8,615.00	7,458.00	1,157.00	2,311.57	1,124.94	1,587.52	750.00
	20	8,615.00	7,084.00	1,531.00	2,025.28	974.28	1,733.14	750.00
	21	8,615.00	6,883.00	1,732.00	1,652.54	754.91	1,419.61	677.45
28 June	13	8,105.00	6,426.00	1,679.00	1,569.11	737.11	1,430.34	750.00
	14	8,440.00	6,769.00	1,671.00	2,083.73	1,208.73	1,977.07	750.00
	15	8,440.00	7,289.00	1,151.00	2,535.48	1,133.49	1,573.04	750.00
	16	8,440.00	7,378.00	1,062.00	2,661.19	1,149.20	1,990.02	750.00
	17	8,615.00	7,581.00	1,034.00	2,612.60	1,177.50	1,772.73	750.00
	18	8,615.00	7,157.00	1,458.00	2,601.22	1,532.72	2,104.44	750.00
	19	8,615.00	6,897.00	1,718.00	1,698.89	1,354.89	1,607.19	749.00
	20	8,615.00	6,750.00	1,865.00	1,648.53	1,112.53	1,638.02	146.18
CAISO Non-Emergency Hours								
14 June	11	8,650.00	6,967.00	1,683.00	2,748.46	1,579.67	2,224.70	738.47
	12	8,650.00	7,191.00	1,459.00	3,187.96	978.94	2,052.02	269.34
	13	8,650.00	7,025.00	1,625.00	3,364.29	2,049.38	2,471.81	749.35
15 June	15	7,931.00	7,098.00	833.00	3,015.59	1,272.10	1,617.88	716.30
	16	7,931.00	7,102.00	829.00	2,951.51	1,250.01	1,778.39	750.00
	17	7,810.50	6,845.00	965.50	2,989.30	1,298.80	1,682.79	706.19
	21	7,810.50	6,039.00	1,771.50	356.90	239.90	330.98	237.61
26 June	12	8,469.50	7,076.00	1,393.50	1,385.78	980.60	1,145.07	229.83
	13	8,590.00	7,301.00	1,289.00	1,158.68	1,053.08	901.06	459.52
	14	8,590.00	7,534.00	1,056.00	1,760.09	1,406.79	1,187.25	750.00
	15	8,590.00	7,587.00	1,003.00	2,356.37	1,324.37	1,233.14	750.00
27 June	N/A	N/A	NA	NA	N/A	N/A	N/A	N/A
28 June	11	8,130.00	6,434.00	1,696.00	822.01	708.01	798.83	213.44
	12	8,130.00	6,549.00	1,581.00	1,193.84	529.53	1,083.96	573.87
	21	8,615.00	7,077.00	1,538.00	1,155.91	1,074.91	1,105.65	667.22
	22	8,615.00	7,012.00	1,603.00	567.27	567.27	567.27	544.34

Notes:
(B): Klein (April 1998).
(C): CEMS data, adjusted for Daylight Savings Time.
(D) – (F): Ancillary service data from CAISO website.
(G): Price data from CAISO website.
Emergency hour designation from CAISO website.

Fourth, the output in particular hours can be materially impacted by units coming on-line as noted above.

This analysis does not demonstrate an absence of economic withholding, as it cannot rule out economic withholding during the non-emergency hours, but it does indicate that the true output gaps is actually not so large that it cannot be accounted for by ancillary service requirements. Moreover, the analysis does not demonstrate an absence of physical withholding during the emergency hours, it merely shows that given the units that were available at any price, there was a shortage. Thus, if the outages were real, the problem was shortage, not economic withholding.

D. Output Gaps in High-Priced Hours

The output gap calculations in Joskow-Kahn Table 8[107] also provide the basis for conclusions by Joskow-Kahn regarding economic withholding but have limitations similar to Joskow-Kahn Table 15. Table 8 only includes hours in which the real-time price exceeds $120,[108] so unlike Joskow-Kahn Table 15 it does not include hours in which rational competitive firms lacking market power would have reduced output in real time, but unlike Joskow-Kahn Table 15, Joskow-Kahn Table 8 is not limited to days on which it was very likely economic to operate all available units. Joskow-Kahn Table 8 includes every real-time price spike, even if the spike occurred on a day on which day-ahead prices were relatively low, and the calculated output gap includes the capacity of offline units.

The output gap in Joskow-Kahn Table 8 includes, for example, the output of units not operating in hour ending 22 of June 1 when real-time prices spiked to $125.70 before falling to $24.25. On June 6 there were two high priced hours (16 and 17) on a day with moderate to low day-ahead prices. Similarly, in hour ending 1 on June 16 the price spiked to $164.07 in the south from $61.88 the hour before ($2.20 the hour before that) before falling to $29.44 in the following hour. Similarly, prices spiked to $185.09 in hour ending 22 of June 23 after being $59.42, $35.26 and $71.63 in the preceding three hours. Simply assuming that units should be on line to respond to price spikes, even when the day-ahead price was low is not a meaningful test of strategic withholding, as units may have been off-line during these hours either as a result of outages, economics or simply a lack of perfect foresight. The failure of generators to operate could therefore reflect a lack of perfect foresight, poor economics or forced outages, as well as possible withholding. We have shown that the CEMS data suggest that it would likely have been unprofitable for a number of units to have operated on June 1-11, 16, 17, 21 and 23. Joskow-Kahn Table 8 includes hours with real-time price spikes on days with low prices, days not included in the set for which Joskow and Kahn analyzed the profitability of unit operation, such as hour 22 on June 1; hours 16 and 17 on June 6; hours 15 and 16 on June 20; and hours 17, 18, 19 and 20 on Sunday, June 25.

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107 Joskow-Kahn (July), p. 19.

108 It should be noted that the data for Duke and Mirant in NP-15 in Table 8 in Joskow-Kahn was apparently calculated based on SP-15 real-time prices rather than NP-15 real-time prices. This is corrected in Table 33 below, resulting in a slight increase in the calculated output gap in NP-15

It can be seen in Table 33 that if Joskow-Kahn Table 8 is revised to reflect the daylight savings time reporting of the CEMS data the calculated output gap rises by about 25 MW in NP-15 and falls by about 125 MW in SP-15. If the output gap calculation is further adjusted to exclude the output of off-line units, the calculated output gap falls by roughly 250 MW in NP15 and about 1,700 MW in SP-15.

Table 33
Output Gap (MW)
Real-Time Prices > $120/MWh

	Joskow-Kahn Calculation			Replication			Adjusted for Outages		
Owner	**Maximum Output (A)**	**Mean Output (B)**	**Output Gap (C)**	**Maximum Output (D)**	**Mean Output (E)**	**Output Gap (F)**	**Maximum Output (G)**	**Mean Output (H)**	**Output Gap (I)**
NP-15									
Duke	1,526	1,414	112	1,526	1,405	121	1,463	1,405	58
Mirant	2,719	1,936	783	2,719	1,921	798	2,527	1,921	605
Total	4,245	3,350	895	4,245	3,326	919	3,990	3,326	664
SF									
Mirant	213	155	58	213	157	56	208	157	51
Total	213	155	58	213	157	56	208	157	51
SP-15									
AES/ Williams	3,681	2,482	1,199	3,681	2,515	1,166	2,960	2,515	445
Duke	733	594	139	733	611	122	690	611	80
Dynegy	2,000	1,002	998	2,000	1,033	967	1,538	1,033	504
Reliant	3,487	2,221	1,266	3,487	2,267	1,220	3,107	2,267	840
Total	9,901	6,299	3,602	9,901	6,426	3,475	8,295	6,426	1,869
Z-26									
Duke	1,037	950	87	1,037	960	77	1,037	960	77
Total	1,037	950	87	1,037	960	77	1,037	960	77
CAISO Total	15,396	10,754	4,642	15,396	10,869	4,527	13,529	10,869	2,660

Note:
Joskow-Kahn used SP-15 prices in calculating the output gap for NP-15. The replication uses NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.

Sources:

(A) – (C): Joskow-Kahn (July), Table 8.
(D) – (G): CEMS data, adjusted for Daylight Savings Time.
(F): Col. (D) – Col. (E).
(I): Col. (G) – Col. (H).
(G): Excludes capacity of off-line units.

The calculated output gap in Table 33 includes the output gap attributable to the normal ramping of units from lower to higher output levels as prices rise. If the output gap is recalculated excluding high real-time price hours following or preceding hours with average prices below $120, then the gap falls by almost an additional 300 MW in NP-15 and more than 400 MW in SP-15 as shown in Table 34. The calculated output gap of 1,926 in Table 34 is basically the same as the output gap of 1,889 MW we reported in Table 21 of our earlier paper or 1,862 MW calculated on the same basis after adjustment for daylight savings time (Table 26 above).

Table 34 Output Gap for Non-Ramping Hours (MW) Real-Time Prices > $120/MWh (Excluding Capacity of Off-Line Units)						
	Joskow-Kahn Calculation			High-Priced Non-Ramping RT Hours, Adjusted for Outages		
Owner	Maximum Output (A)	Mean Output (B)	Output Gap (C)	Maximum Output (D)	Mean Output (E)	Output Gap (F)
NP-15						
Duke	1,526	1,414	112	1,441	1,378	63
Mirant	2,719	1,936	783	2,567	2,255	312
Total	4,245	3,350	895	4,009	3,634	375
AS Procurement (excl. replacement)			1,137			1,092
AS Procurement (incl. replacement)			1,553			1,649
Undispatched AS						1,197
SF						
Mirant	213	155	58	210	160	50
Total	213	155	58	210	160	50
AS Procurement (excl. replacement)			29			33
AS Procurement (incl. replacement)			46			61
Undispatched AS						28
SP-15						
AES/Williams	3,681	2,482	1,199	2,974	2,658	316
Duke	733	594	139	716	674	42
Dynegy	2,000	1,002	998	1,561	1,191	370
Reliant	3,487	2,221	1,266	3,178	2,446	733
Total	9,901	6,299	3,602	8,429	6,969	1,460
AS Procurement (excl. replacement)			986			1,164
AS Procurement (incl. replacement)			1,606			2,100
Undispatched AS						1,503
Z-26						
Duke	1,037	950	87	1,037	996	41
Total	1,037	950	87	1,037	996	41
AS Procurement (excl. replacement)			34			34
AS Procurement (incl. replacement)			67			78
Undispatched AS						31
CAISO Total	15,396	10,754	4,642	13,685	11,759	1,926
CAISO AS Procurement (incl. replacement)						2,323
CAISO AS Procurement (excl. replacement)						3,888
Undispatched AS						2,759

Note:
Joskow-Kahn uses SP-15 prices for their high priced hours for all zones. LECG calculation uses NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.
Sources:
(A) – (C): Joskow-Kahn (July), Table 8.
(D) – (E): CEMS data, adjusted for Daylight Savings Time.
(F): Col. (D) – Col. (E).
Ancillary service data from CAISO website.

The calculated output gap is 1,614 MW smaller in the high-priced, non-ramping hours than in the high-priced ramping hours and the difference is statistically significantly different from zero at the 99.9 percent confidence level.

The data in Table 34 indicate an "output gap," although the calculated output gap is less than ancillary service procurement from generation in NP-15 and for the CAISO overall, as well as less than the calculated undispatched ancillary service capacity. In other words, the capacity not used to generate energy could have been supplying required ancillary services. Moreover, as noted above, the output gap calculation makes no allowance for unit deratings, environmental limits, ISO dispatch decisions, or the output gap on units coming on-line, and may be calculated based on a capacity in excess of the units actual capacity under real-time conditions and therefore undispatched capacity not providing ancillary services may not actually reflect economic withholding. Joskow and Kahn, however, conclude based on the data in their Table 8 that "generators withheld capacity far in excess of what can be explained by historical outage rates or demand for ancillary services."[109] The data do not support such a conclusion. The Joskow-Kahn withholding analysis does not appear to contain any statistical analysis of historical outages rates and as seen above, the calculated output gap can in fact be largely accounted for, within the limitations of the publicly available data, by the demand for ancillary services, and the calculated output gap reflects several factors other than economic withholding (misstated capacity, environmental limits, deratings and operating problems, ISO dispatch instructions).

As discussed in connection with Table 30 above, the remaining output gap could be attributable to a variety of factors. First, the actual capacity bid in to the CAISO market may be less than the capacity assumed by Joskow and Kahn for several reasons. These considerations include Mirant capacity at Pittsburgh and Contra Costa that is not bid in because it would be above the expected 86 degree limit, capacity not bid in because of deratings, and any difference between the capacities assumed by Klein and actual operating capacity. Second, actual output could also differ from the capacity bid into the CAISO market for a variety of reasons. These considerations could include supplementary energy offered at high prices, environmental limits such as the 86 degree limit that bound at lower than expected output levels in real time, minor operational problems that prevented the unit from operating at full capacity, serious operating problems that required substantial output reductions, ISO dispatch instructions, as well as mismetering in the CEMS data.

Once again, we lack the data required to fully adjust the calculated output gap for these factors, but can provide a degree of insight into their magnitude by recalculating the output gap for the hours in which the CAISO was operating under a stage 1 or higher level emergency and for the non-emergency hours, as before. The significance of this distinction is that a stage 1 emergency declaration indicates that there was a shortage of capacity *at any price*. Table 35 reports the calculated output gap for the hours of stage 1 or higher emergency. It can be seen that the calculated output gap averages 218 MW in the North and 1,422 MW in the South during these hours in which it is known that there was not enough capacity available at any price, and thus that there was a shortage, not economic withholding.[110] The calculated output gap on the steam

[109] Joskow-Kahn (July), p. 18.

[110] The data we present do not exclude the possibility that the shortage conditions could have been a result of physical withholding. We comment on physical withholding issues in Section V.

units is generally lower than the calculated undispatched ancillary services, but not all of these ancillary services were being provided by units covered by the CEMS data, as Joskow and Kahn and we have noted.

Table 35
Output Gap (MW) Real-Time Prices > $120/MWh
June 2000

Owner	Joskow-Kahn Calculation: Maximum Output (A)	Joskow-Kahn Calculation: Mean Output (B)	Joskow-Kahn Calculation: Output Gap (C)	High-Priced Non-Ramping RT Emergency Hours, Adjusted for Outages: Maximum Output (D)	High-Priced Non-Ramping RT Emergency Hours, Adjusted for Outages: Mean Output (E)	High-Priced Non-Ramping RT Emergency Hours, Adjusted for Outages: Output Gap (F)
NP-15						
Duke	1,526	1,414	112	1,467	1,427	41
Mirant	2,719	1,936	783	2,626	2,449	177
Total	4,245	3,350	895	4,093	3,875	218
AS Procurement (excl. replacement)						943
AS Procurement (incl. replacement)						1,637
Undispatched AS						1,104
SF						
Mirant	213	155	58	213	141	72
Total	213	155	58	213	141	72
AS Procurement (excl. replacement)						26
AS Procurement (incl. replacement)						65
Undispatched AS						29
SP-15						
AES/Williams	3,681	2,482	1,199	3,023	2,699	324
Duke	733	594	139	733	704	29
Dynegy	2,000	1,002	998	1,602	1,268	335
Reliant	3,487	2,221	1,266	3,328	2,593	734
Total	9,901	6,299	3,602	8,686	7,265	1,422
AS Procurement (excl. replacement)						1,252
AS Procurement (incl. replacement)						2,359
Undispatched AS						1,671
ZP-26						
Duke	1,037	950	87	1,037	996	41
Total	1,037	950	87	1,037	996	41
AS Procurement (excl. replacement)						42
AS Procurement (incl. replacement)						92
Undispatched AS						39
CAISO Total Output Gap	15,396	10,754	4,642	14,029	12,277	1,752
CAISO AS Procurement (excl. replacement)						2,264
CAISO AS Procurement (incl. replacement)						4,153
CAISO Undispatched AS						2,844

Sources:
(A) - (C): Joskow-Kahn (July), Table 8. Joskow-Kahn uses SP-15 prices for all zones.
(D) – (E): CEMS data, adjusted for Daylight Savings Time. The replication uses NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.
(F): (D) – (E).
Ancillary services data from CAISO website.

The hours covered in Table 34 also included a number of hours with high real-time prices that were not stage 1 (or higher) emergencies. We have separately calculated the output gap for these hours, and report it in Table 36. It can be seen that the calculated output gap is somewhat larger in the non-emergency hours than in the emergency hours, particularly for Mirant. It should be kept in mind, however, that Mirant was released from Delta Dispatch restrictions during emergencies, but could be subject to these restrictions absent an emergency, thus creating an apparent output gap, during high priced non-emergency hours.

Table 36 Output Gap (MW) Real-Time Prices > $120/MWh June 2000						
	Joskow-Kahn Calculation			**High-Priced Non-Ramping RT Non-Emergency Hours, Adjusted for Outages**		
Owner	**Maximum Output (A)**	**Mean Output (B)**	**Output Gap (C)**	**Maximum Output (D)**	**Mean Output (E)**	**Output Gap (F)**
NP-15						
Duke	1,526	1,414	112	1,410	1,321	89
Mirant	2,719	1,936	783	2,498	2,026	472
Total	4,245	3,350	895	3,909	3,348	561
AS Procurement (excl. replacement)						1,268
AS Procurement (incl. replacement)						1,663
Undispatched AS						1,307
SF						
Mirant	213	155	58	207	184	23
Total	213	155	58	207	184	23
AS Procurement (excl. replacement)						41
AS Procurement (incl. replacement)						56
Undispatched AS						27
SP-15						
AES/Williams	3,681	2,482	1,199	2,910	2,605	305
Duke	733	594	139	693	634	59
Dynegy	2,000	1,002	998	1,507	1,091	416
Reliant	3,487	2,221	1,266	2,984	2,253	731
Total	9,901	6,299	3,602	8,095	6,584	1,511
AS Procurement (excl. replacement)						1,050
AS Procurement (incl. replacement)						1,763
Undispatched AS						1,284
ZP-26						
Duke	1,037	950	87	1,037	997	41
Total	1,037	950	87	1,037	997	41
AS Procurement (excl. replacement)						22
AS Procurement (incl. replacement)						60
Undispatched AS						16
CAISO Total Output Gap	15,396	10,754	4,642	13,247	11,111	2,136
CAISO AS Procurement (excl. replacement)						2,381
CAISO AS Procurement (incl. Replacement)						3,542
CAISO Undispatched AS						2,633

Sources:
(A) - (C): Joskow-Kahn (July), Table 8. Joskow-Kahn uses SP-15 prices for all zones.
(D) – (E): CEMS data, adjusted for day-light savings time. The replication uses NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.
(F): (D) – (E).
Ancillary services data from CAISO website.

Moreover, the average output gap inevitably conceals some of the underlying variation, as the degree of shortage was of course larger in some hours than in others.

V. PHYSICAL WITHHOLDING

Although Joskow and Kahn assert at several points in their paper that they provide evidence of physical withholding, the paper does not actually contain any evidence that operable capacity has been physically withheld from any market. They appear to simply assume that units that were not on-line during high priced hours were physically withheld.[111]

Joskow and Kahn draw strong conclusions regarding withholding from their Tables 12 (Table 37 below) and 13 (Table 38 below) that are inconsistent with the data and economic analysis. With respect to Joskow-Kahn Table 12, portraying the output of steam and GTs on June 12-17, 21-23 and 26-30, they state that:

> "The Steam Part Day capacity shows that many units were started daily but only ran for part of the day. The Big GT and Small GT entries reflect capacity that is running no more than seven or eight hours per day. Given the inefficiency and high emissions rates of the Big GT and Small GT units, in a competitive market we would expect to see them operating only on days when all generating units with lower costs and emissions were already supplying the market to the extent possible."[112]

These conclusions are based on several false premises. First, the statement that steam units operating part of the day indicates units that were started daily is not correct. While some of this capacity reflects units that are taken on and off line each day it also reflects units coming on line in response to high demand after several days of low load as well as units coming off line after sustained periods of high load, for repairs, or simply for a weekend. Thus, the large level of partial day operation on June 16 reflects units coming off line for the weekend (and much lower load) when the weather broke after having operated at high levels for several days. Similarly, the large level of partial day operation on June 13 reflects units coming on line on Tuesday in response to the hot weather, much higher load, and high real-time prices.

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[111] Joskow-Kahn (July), pp. 23.

[112] Joskow-Kahn (July), p. 24.

Table 37 Joskow-Kahn Table 12 Total SP-15 Capacity Committed On-Peak (MW)								
Date	**Steam All Day**	**Steam Part Day**	**Long Beach**	**Big GT**	**Small GT**	**Total Capacity**	**ISO Peak**	**Total Capacity/ ISO Peak**
June 12	6,271	734	560	0	19	7,584	37,132	0.204
June 13	6,855	1,330	560	476	271	9,492	42,288	0.224
June 14	7,902	763	560	476	271	9,972	43,447	0.230
June 15	7,422	356	560	236	260	8,833	43,146	0.205
June 16	6,727	2,273	560	0	0	9,560	39,823	0.240
June 17	7,520	480	0	0	0	8,000	33,800	0.237
June 21	6,101	603	560	476	223	7,963	41,414	0.192
June 22	6,491	906	560	350	260	8,566	40,089	0.214
June 23	7,506	283	560	0	0	8,349	37,228	0.224
June 26	7,568	952	560	476	271	9,826	42,672	0230
June 27	7,889	471	560	476	271	9,666	42,693	0.226
June 28	7,729	806	560	476	256	9,826	42,303	0.232
June 29	8,064	296	560	476	260	9,655	41,606	0.232
June 30	7,714	500	560	0	0	8,774	38,187	0.230
Source: Joskow-Kahn (July), Table 12.								

Second, the statement by Joskow and Kahn that GTs should only be operating on days when all other generating units were in operation supplying the market is incorrect. An important reason for having quick-start units such as GTs is to respond to unanticipated changes in demand or supply that cannot be met by slow starting steam units. Thus, GTs are sometimes running because of load forecasting mistakes or real-time outages. Joskow-Kahn Table 5 shows that average day-ahead prices were low on June 13 and June 21 ($87 and $63), reflecting expected supply and demand conditions, but real-time prices were much higher, reflecting higher than expected demand. Another reason for using GTs to meet load is to meet short lived demand peaks of an hour or so that would not justify starting up a steam unit that must run for several or many hours and incurs material start-up costs. A third reason for using GTs, rather than a lower cost steam unit, to meet load can be that energy is needed at the location of the GT. For example, in NP 15 the Potrero GTs were often started to meet demand inside the San Francisco constraint that could not have been met by steam units elsewhere in NP 15 since the PG&E Hunters Point units were off line throughout June 2000. Some of the Southern California GTs are also located in load pockets, such as San Diego and may have been started at times to manage congestion in these load pockets. Fourth, many GTs are not dispatchable but once started must run at capacity. As a result, they usually cannot provide spinning reserves that may therefore need to be provided by the ISO holding back generation on steam units with lower energy bids than the GTs.

All of these considerations are reasons why it can be efficient for GTs to be operating on real-world electric systems at the same time that steam units with lower incremental energy costs are off-line or not fully dispatched.

Joskow and Kahn also draw strong conclusions from their Table 13, replicated and expanded below as Table 38. They state that:

> "For each of the 14 high-price days, Table 13 lists steam units that did not run at all. Together with Table 12, this table shows that significant amounts of steam capacity did not operate on days when more costly and polluting capacity did run. Among the units listed in Table 13 are some with low emissions rates, such as Redondo Beach 8, Alamitos 5 & 6, and El Segundo 4. If the operators of these plants were acting like price-takers, they would have run as much low-cost and low-emissions capacity as possible before turning to the highest-cost units. Even if the units had minor operating problems, they would still have run at some level if the suppliers were behaving competitively."[113]

[113] Joskow-Kahn (July), p. 24.

Table 38
Joskow-Kahn Table 13
Full Outage Pattern for Uncommitted Steam Units

Date	AES/ Williams	Reliant	Dynegy	Average PX Price SP-15	Average RT Price SP-15
12 June	A1, A6, R5, R6	Et3, C1, 31-2	Ec3, Es1-4	67.21	70.77
13 June	A1, A6, R5, R6	C31-2	Es3	88.56	255.43
14 June	A1, R5, R6	C31	Es3	250.00	364.33
15 June	A1, R5, R6		Es3	324.44	163.83
16 June	A1, R5, R6	C31-2		243.46	56.10
17 June	A1, R5, R6	Et1-2, C1, 31-2	Es1, 2; Ec1-3	59.87	52.48
18 June	A1, R5, R6	Et1-2, C1, 31-2	Es1, 2; Ec1-3	46.12	38.42
19 June	R5	C1, C31-2	Es2; Ec1-3	60.89	93.06
20 June	R5, R8	Et1-2, C1, C31-2	Es2; Ec1-3	50.69	72.72
21 June	R5, R8	M1, Et1, 2, 4; C1-2	Es1, 3; Ec1-3	62.84	216.53
22 June	R5, R8	Et1-2; C1, 2, 32	Es1, Ec1-3	98.88	118.76
23 June	R5, R8	Et1-2, C1, 2, 31-2	Es1, Ec1-3	91.57	61.01
24 June	R5, R8	Et1-2, C1, 2, 31-2	Es1, 2, Ec1-3	60.61	66.02
25 June	R5, R8	Et1-2, C1, 2, 31-2	Es1, 2, Ec1-2	49.64	82.38
26 June	R5, R8	C1-2	Es1-2	122.62	296.18
27 June	R5, R8	C1-2	Es4	228.65	391.16
28 June	R8	C1-2	Es4	319.31	377.45
29 June	A1, R8	C1-2	Es4	364.49	260.12
30 June	A1, R5	C1, 2, 31-2	Es4	332.62	69.14

A= Alamitos; R = Redondo Beach; Ec = Encina; Et = Etiwanda; Es = El Segundo.
C = Coolwater; M = Mandalay.

Sources:
Joskow-Kahn (July), Table 13 and CEMS data.

Notes:
(1) Highlighted days denote days not included in Joskow-Kahn (July) Table 13.
(2) Highlighted days data based on CEMS data, adjusted for day-light savings time. Original data are not so adjusted.

Joskow-Kahn's Table 12 and 13, however, do not provide any evidence that the operators did not run as much low-cost and low-emissions capacity as possible, before turning to the highest cost units, nor do they indicate that the operators failed to continue operating units with minor operating problems. On the contrary, it is apparent from Table 38 that fewer units and less capacity were unavailable on the days with high day-ahead prices than on days with low day-ahead prices. This is consistent with competitive behavior. Joskow and Kahn's conclusions assume that it should be possible to always have all units available on high load days, but that is never the case. There always have been and will be forced outages, and units taken down for repairs when load declines may not yet be available when load rises again. There is no data in Joskow-Kahn Table 12 or Table 38 above that indicates that any of the unit outages reflected strategic physical withholding of capacity rather than forced outages or repair outages.[114] Conversely, our point is not that Table 27 demonstrates that there was no physical withholding of capacity. As we said before, these data do not permit one to determine whether there was physical withholding of capacity by all, some or none of the thermal generators.

The closest Joskow-Kahn comes to providing empirical evidence of physical withholding is to observe that Duke is reputed to have sold 90 percent of its output forward and also had relatively high availability for its units.[115] Joskow-Kahn does not provide comparable outage statistics for any other generators but suggest that the outage rates would be higher. We noted above that the output gap for the Duke units is understated because Klein uses a very low capacity for South Bay 4. The output gap Joskow-Kahn calculates for Duke is lower than the gap they calculate for other companies in part because the Duke output gap is understated by understated capacities and that of other suppliers overstated by overstated capacities. Moreover, we previously observed that the company with the highest level of forward sales was AES which sold all of its output forward. AES also described itself as having had unusually high forced outage rates during 2000.[116] The result of the high forced outage rates was that the company became a net buyer and actually lost money in California during 2000.[117] Similarly, we previously pointed out that another net buyer, PG&E, also had very poor unit availability during June 2000 as none of its Hunters Point units were available.[118]

Apparently the outage conditions were not so clear or simple. Furthermore, the FERC outage report indicates that a number of the units with outage problems during 2000 were not only old units, but they were units that were rarely used in prior years but heavily used during 2000 (e.g., El Segundo 1 and 2, and Etiwanda 1 and 2).[119]

Finally, the units listed in Joskow-Kahn Table 13 as being off line on these high priced days also share the characteristic that they were all previously owned and maintained by SCE and were

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[114] The FERC outage report specifically mentions June outages for installation of AGC at Coolwater (Alta) unit 1 and a catastrophic fan failure in June at unit 2 which kept that unit down for four weeks. The FERC Outage Report also discusses outages at Coolwater 3 beginning with a failure on May 26. FERC Outage report pp. 17-18. Joskow and Kahn may not find the FERC Outage Report to provide conclusive proof that there was no physical withholding but the information in the Outage Report is consistent with the forced outage explanation for non-availability. Other data might show that the non-availability of the units in Table 38 was not due to forced outages, but Joskow and Kahn do not provide any such evidence.

[115] Joskow-Kahn (July), pp. 25-26.

[116] See Stu Ryan, AES Pacific, February 1, 2001, Analyst Presentation.

[117] AES January 29, 2001, press release re: Annual Earnings, Aesc.com/investor/press/index.html.

[118] See Harvey-Hogan (April), p. 46. Joskow-Kahn (July) state that we asserted this, p. 11, but we relied on the same CEMS data that they used for their analysis. It can readily be determined from the CEMS data that the Hunters Points units were not operating during June 2000.

[119] See FERC Outage Report El Segundo 1 and 2, p. 40, Etiwanda 1 and 2, p. 20.

being maintained during June 2000 by SCE. The Duke units listed in Table 14 have all been maintained by PG&E and SDG&E. Perhaps, therefore, the difference in outage rates is attributable to the maintenance practices of SCE.[120] Alternatively, the difference in outage rates might be attributable to differences in the way the units have historically been utilized, with lower outage rates for units that run as base load units and higher outage rates on the units that frequently come on and off-line. These are empirical issues that neither we nor Joskow-Kahn have addressed. The only empirical analysis of outages and examination of individual unit outages is that of the FERC staff, which while not conclusive, did not identify any physical withholding.[121]

VI. MARKET POWER ANALYSIS

Joskow-Kahn addresses a difficult public policy question. With data currently available only to the CAISO and market participants, this question could be answered, although not easily. However, Joskow-Kahn does not have access to these data. Instead Joskow-Kahn uses publicly available data under two distinct approaches. Both of their approaches face the reality that the range of uncertainty in the publicly available data measuring available capacity, capacity used to provide ancillary services, capacity used to generate energy at the intra-hour peak and capacity dispatched down by the CAISO, could exceed the magnitude of any strategic anticompetitive withholding that might have occurred. The CAISO dispatch data would reveal the total available capacity of the on-line units (net of derations, i.e., the upper limit of the units bid in for supplemental energy), and the amount of this capacity that was either used to generate energy, provide ancillary services, or was backed down by the CAISO to manage congestion or balance generation and load. The CAISO dispatch data, moreover, would reveal whether capacity was being economically withheld (i.e., not used to provide energy or ancillary services) in real time during the shortage hours, based on the actual generator schedules and capacity available in each hour. A fundamental limitation of studies based on the CEMS data is that they must be based on very imperfect measures of things the CAISO dispatch data would reveal almost exactly.

The CAISO dispatch data, however, would not provide the information required to determine whether prices have been affected by physical, rather than economic, withholding. This would require the assessment of the causation of each forced outage or unit derating, assessing the impact of start-up and minimum-load costs on decisions to operate, assessing the impact of annual run restrictions on operating decisions. On this point, the FERC staff has examined outage data for a sample of units and concluded the outages they examined did not reflect physical withholding.

The point of the comments above is not that market power never exists, nor that it cannot be detected. Our point is that the methodologies employed by Joskow-Kahn, BB&W and the MSC are not capable of identifying the exercise of market power in stressed conditions. Absent some kind of large offsetting bias, these methodologies will likely always find that market power has been exercised, as real prices will always be higher than simulated prices and a lot higher in

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120 While the comments of the generation owners may be dismissed as self-serving, the FERC Outage Report describes many complaints regarding SCE maintenance practices. See FERC Outage Report, pp. 18, 27, 37.

121 See the FERC Outage Report.

shortage conditions. This outcome is virtually guaranteed by analyses based on simulation models that are non-chronological, omit start-up and minimum load costs, omit reserve requirements, omit environmental limits, omit energy limits, do not reflect actual outages and deratings, and make no allowance for the impact of real-time surprises. Additional error can arise if unit capacities are incorrectly specified and the import supply curve misstated and if the simulation does not reflect the actual market rules that determine prices.

Similarly, withholding analyses that do not take account of outages and deratings, ramping constraints, environmental limits and dispatch rules and procedures will inevitably find economic or physical withholding. Additional error can arise if unit capacities are incorrectly specified.

The first question to ask in assessing whether high prices are materially impacted by economic withholding would be to ask whether there was a shortage. That is, was there inadequate capacity available at any price to meet load and provide required ancillary services. If there was not a physical shortage, then the next step would be to determine whether economic withholding materially contributed to creating an economic shortage. This can be assessed by examining the capacity actually offered to the market for dispatch on each unit, accounting for capacity that was not-available due to ancillary reserve requirements, ramping limits, environmental restrictions or because the unit was not on-line, and examining the dispatch instructions and uninstructed output of the units.

This process could be combined with appropriate cost data to identify capacity that was being economically withheld from the market, but it would then be necessary to evaluate whether this economic withholding reflected the exercise of market power, or normal competitive processes, such as allocation of the output of an energy limited unit to the highest valued hours, the extra-ordinary costs that might be associated with operation at very high levels, or a result of pay-as-bid market features.

A third question would be to ask whether the physical withholding of capacity for the purpose of exercising market power materially contributed to the economic shortage. Determining whether on-line capacity was physically withheld from the market requires determining whether it was not available because of an outage, derating or performance problem (low tide, high ambient temperature, etc.). We see no easy short-cut. Higher than average forced outage rates and deratings will usually produce higher than average prices but it does not follow that all above average outage occurrences reflect the exercise of market power. Moreover, capacity may be physically withheld from the market for reasons unrelated to the exercise of market power, such as credit risk or compliance with laws, regulations and other restrictions.

Evaluation of withholding in day-ahead forward markets, and thus asking whether off-line capacity should have been on-line, is harder still, particularly in regions lacking day-ahead markets, or regions like California with very inefficiently structured day-ahead markets.[122] If day-ahead markets do not exist or are structured to make efficient day-ahead unit commitment impossible, market inefficiency and inefficient unit commitment outcomes should not be attributed solely to the exercise of market power.

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[122] The lack of multi-part bids, the inability to reflect operating inflexibilities in bids, the lack of simultaneous optimization of bids and schedules over the day and across energy and ancillary services.

Given the design of the California market, however, even the FERC may not be able to determine from the dispatch data in all instances whether capacity was economically withheld in order to exercise market power, or whether it was economically withheld because of mistaken bids arising from imperfect foresight, which are an inevitable by product of the California market design.

Ultimately, it is impossible to prove the absence of any withholding or any exercise of market power without analyzing the reasons for every outage, derating, and decision not to operate by every supplier, which has not been undertaken by any study. The available information, however, has several elements that suggest that the exercise of market power by California thermal generators was not the primary cause of the high prices in California during 2000-2001. First, electricity prices were consistently high both inside and outside California, which strongly suggests that the problem was not the exercise of locational market power inside California but a widespread shortage of energy and/or capacity in the WSCC. Indeed, prices have at times been higher outside of California than within California due to transmission constraints on exports. Second, if thermal unit owners were engaged in a simple withholding of generation, then they would not have exceeded the environmental limits on their output. With the benefit of hindsight, it appears indisputable that perfectly competitive thermal generator owners of constrained units blessed with perfect foresight would have offered less capacity into the market from a number of units in many hours during the spring and summer of 2000 than they actually did, not more capacity, and prices in such a perfectly competitive market would have been higher, not lower, than the actual prices in many of the hours in early 2000. Third, if the high prices in California were attributable to simple withholding by a few thermal generators in California, could these generators be exercising sufficient market power to raise prices off-peak as well as on-peak throughout the entire WSCC?

VII. CONCLUSION

While it is important that allegations of the exercise of market power be carefully investigated, the evidence to date that the high prices in California and the WSCC arise mainly from the exercise of market power by California thermal generators is far from compelling. As Joskow and Kahn have highlighted, many factors contributed to higher prices in California during 2000 and 2001, and the market power theme is only, at most, part of the story. The import of their analysis is not to prove that market power has been exercised but, rather, to suggest that it might be important. The import of the sensitivity analyses summarized here is not to prove that market power has not been exercised but, rather, to suggest that it is unlikely to be the dominant factor and may not even be significant. By contrast, there appears to be little disagreement that other problems of shortage and bad market design are at least large enough to dictate that the solution requires more than just market power mitigation devices.

We observed in April that analysis of the possible exercise of market power should not divert attention from the need for California to:

1. Pay its bills;
2. Raise retail rates, at least at the margin, to reflect the wholesale market price;
3. Assign the financial responsibility for paying electricity bills to someone;

4. Make it clear if and, if so, how, environmental regulations will be modified; and
5. Adopt LMP and reform the wholesale market design.

Steps 1 through 4 have subsequently been taken either by the state or the FERC. Step 5 remains.

The designed inefficiency of the California market has directly raised prices and also greatly complicated diagnosis of the cause of the high prices. The California ISO should shift immediately to a bid-based least-cost dispatch in real-time and bid-based least-cost congestion management in day-ahead markets.[123] Further, the FERC should recognize that directing the CAISO to maintain minimum WSCC reserve levels at any cost has an important impact on the cost of meeting load in a shortage situation. Rather drive out high-cost supply, it would be better public policy to recognize that every MW of the 3,000 or so MW of regulation and reserves that the CAISO seeks to schedule is not worth $1,000, $750, $500 or even $250/MW.[124]

These market reforms would be important no matter what the resolution of the analysis of the exercise of market power.

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[123] California Independent System Operator, "Proposed Market Stabilization Plan of the California Independent System Operator Corporation Provided in Response to Letter Order of March 30, 2001," Submission to Federal Energy Regulatory Commission, April 6, 2001. This plan includes some of the suggested reforms, but also introduces other features such as price discrimination between various sources of supply that would likely complicate market operations.

[124] This issue is discussed further in Harvey-Hogan, pp. 25-26. See also John D. Chandley, Scott M. Harvey, and William W. Hogan., “Electricity Market Reform in California,” Comments in FERC Docket EL00-95-000, Center for Business and Government, Harvard University, November 22, 2000.

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