MARKET POWER AND MARKET SIMULATIONS

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EXECUTIVE SUMMARY

Systematic exercise of market power could reduce or eliminate the consumer benefits of restructuring electricity generation markets. It is important, therefore, to understand and address the problem. However, high wholesale electricity prices, the most prominent symptom of an exercise of market power, could arise also from conditions of high cost and shortages. Since the major policy implications differ for different causes of high prices, it is essential to separate the effects. Confusing an exercise of market power with other conditions could result in costly decisions and a neglect of real problems in a way that would increase rather then mitigate problems of electricity restructuring.

Direct analysis of the behavior of individual generators requires detailed data not available in the public domain, although the key elements would be available to system operators. As a more indirect approach, many analyses of the exercise of market power in electricity markets focus on comparing actual market prices with simulated prices intended to reflect aggregate competitive conditions. Although appealing in principle, this indirect simulation approach imposes substantial burdens on the preparation of the simulation model to isolate the effect of an exercise of market power rather than higher costs, increased demand or capacity constraints.

It is inherently difficult to eliminate errors in a simulation model and isolate the effect of an exercise of market power. The usual argument for why market power presents a special problem in the case of electricity emphasizes the tendency of the supply curve to rise rapidly at high levels of output near the capacity of the system. In this range, a small level of supply withholding to exercise market power could produce a large price increase. Unfortunately, this same feature means that small errors in the simulation model could produce large changes in the simulated price in this same range.

This analytical problem inherent in simulation models compounds when the traditional tools for analyzing electricity markets give way to even more approximate models. This practice simplifies the simulation but expands further the possibility that errors in the model could obscure the separate effects that lead to differences between observed and simulated prices. Such use of simplified models has been prominent in many analyses that find a ubiquitous exercise of market power and has even been suggested as a trigger for automatic implementation of substantial market interventions to mitigate market power.

In addition to estimating the competitive price, therefore, it is equally important to identify the sensitivity of that estimate to changes in assumption that might reflect errors in the model. If the sensitivity analysis reveals relatively small changes in the simulated price, the errors may not be important. But if the sensitivity analysis produces a wide range of prices, a range large enough to include the observed prices, then the simplified model would not be able to distinguish between the exercise of market power or the errors in the simulation model.

The present study conducts such a detailed sensitivity study using the most prominent simulation analysis that relies solely on publicly available data. Given the problems of the simulation model, the purpose is not to produce a better estimate of the competitive prices. Rather, the focus is more on the degree of confidence that we can place on any particular estimate. As a first step, an attempt to independently replicate the simulated prices was not fully successful and this itself illustrates the difficulty of building a reliable model. Then with this baseline, various tests approximated the impact of simplifying assumptions.

The results produce a wide range of simulated prices, a range that includes observed market prices. This indicates that the sensitivity analysis of simulation results is essential in assessing any policy conclusions. Drawing inferences regarding competition based on comparisons between actual prices and those simulated in these simple models could produce substantial errors. The difference between the actual and simulated prices could arise from the real-world constraints omitted from the model in conjunction with purely competitive behavior, or the difference could arise from the exercise of market power by sellers that are able to raise prices because of constraints omitted from the model. One simply cannot tell from these simulations. The error is larger than the effect being estimated.

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I. INTRODUCTION

The potential for the exercise of market power can provide an important limitation on the ability of consumers to benefit from restructuring of electricity generation markets. It is therefore important to identify circumstances in which market power is being or has been exercised, to understand the reasons underlying the ability of market participants to exercise market power, and to address the market power policy implications.

At the same time, it is also important to recognize that high prices alone do not signify the exercise of market power as high prices could also arise either from high costs or capacity shortage conditions. Moreover, since many of the remedies for high prices arising from the exercise of market power (e.g., divestiture and mitigation) are quite different from the remedies for high prices arising from high costs or capacity shortage (e.g., more investment in low cost electric generating capacity), it is important to empirically distinguish among the various causes of high prices. One methodology that has been used in a number of papers to assess whether prices have been impacted by the exercise of market power is to simulate the competitive level of prices and then to compare the simulated prices with actual prices.

Several papers have discussed the methodological limitations of studies that attempt to make inferences regarding the exercise of market power by comparing actual market clearing prices to prices calculated by simulation models, particularly if those models do not include factors that

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can materially raise the cost of meeting load in actual operations, e.g., the need for operating reserves, start-up and minimum load costs of operating units, transmission congestion, generation ramping constraints, uncertain load, unit operating inflexibilities, environmental restrictions, and uncertain outages.[2] There is, however, a continuing series of studies that report finding pervasive exercise of market power in wholesale electricity markets based on comparisons of actual and simulated prices in California,[3] PJM,[4] and New England.[5]

While the potential exercise of market power in deregulated wholesale electricity markets is an important concern that deserves careful scrutiny, the methodology employed in these simulation studies appears likely to find that market power has been exercised regardless of the competitiveness of the market. The Bushnell and Saravia study of New England even finds a spread between actual and simulated prices in a region in which most observers, including the market monitor using different methods, have recognized that actual settlement prices have been artificially depressed by inefficient rules that give rise to substantial uplift costs.[6]

In view of the continuing series of papers that draw strong conclusions regarding the competitive level of prices based on models and assumptions that are inconsistent with the actual operation of the transmission system, it is appropriate to attempt to provide some sensitivity analyses that provide insight into the importance of these methods and assumptions. We decided to develop

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[2] Scott M. Harvey and William W. Hogan, “Issues in the Analysis of Market Power in California,” October 27, 2000 (hereafter Harvey-Hogan October 2000); 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 2001); Scott M. Harvey and William W. Hogan, “Identifying the Exercise of Market Power in California,” December 28, 2001 (hereafter Harvey-Hogan December 2001); and Rajesh Rajaraman and Fernando Alvarado, “[Dis]proving Market Power,” January 24, 2002 (revised March 2, 2002).

[3] Severin Borenstein, James Bushnell, and Frank Wolak, “Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market,” August 2000 (hereafter BB&W); Frank Wolak, R. Nordhuas and Carl Shapiro, “An Analysis of the June 2000 Price Spikes in the California ISO’s Energy and Ancillary Services Markets,” September 2000; Paul Joskow and Edward Kahn, “A Quantitative Analysis of Pricing behavior in California’s Wholesale Electricity Market During Summer 2000,” March 2001 (hereafter Joskow-Kahn March 2001); Paul Joskow and Edward Kahn, “Identifying the Exercise of Market Power: Refining the Estimates,” July 5, 2001 (hereafter Joskow-Kahn July 2001); Paul Joskow and Edward Kahn, “A Quantitative Analysis of Pricing Behavior in California’s Wholesale Electricity Market During Summer 2000: the Final Word,” February 4, 2002 (hereafter Joskow-Kahn February 2002); Severin Borenstein, James Bushnell and Frank Wolak, “Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market,” June 2002.

[4] E. T. Mansur, “Environmental Regulation in Oligopoly Markets: A Study of Electricity Restructuring,” November 2001, and Erin Mansur, “Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market,” April 2001. PJM covers a region in the Mid-Atlantic states.

[5] James Bushnell and Celeste Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” February 2002 (hereafter Bushnell and Saravia). Bushnell and Saravia find an average price markup that exceeds the threshold recently proposed by the California ISO as a trigger for automatic implementation of market power mitigation; California ISO MD02 proposal submitted to FERC, May 1, 2002.

[6] David B. Patton, “An Assessment of Peak Energy Pricing in New England During Summer 2001,” November 2001. Mario Depillis, ISO-NE, “Reserve Market Issues in Nepool,” September 13, 2000; Mario Depillis, ISO-NE, “Limitations of Bid Characteristics,” October 24, 2000; ISO New England, Inc., “Management Response to Summer 2001 Pricing,” March 2002; ISO New England, “Power Supply,” no date; and David Patton, Robert Sinclair and Pallas Van Schack, “Competitive Assessment of the Energy Market in New England,” May 2002.

these sensitivity analyses for some of the California simulations, but some or all of the same methodological difficulties exist in all of these studies: operating reserve requirements excluded; the impact of start-up and minimum load costs not considered; environmental restrictions missing; the chaos and uncertainty of real-time operations simplified to perfect dispatch decisions supported by perfect hindsight; and the variability of real-world unit performance and outages replaced with idealized assumptions. These sensitivity analyses are discussed in Section II. It is seen that these sensitivity analyses are necessary, addressing these other factors has a large impact on simulated prices for California during June 2000. If these factors are taken into account, the simulated prices are generally at or above the level of actual prices. Section III turns to a discussion of the New England Power Pool (NEPOOL) simulation results. These results include sensitivity cases that provide tests of ability of these simple simulation models to predict market-clearing prices. The tests indicate that the simulation model produces results that violate the simplifying assumptions of the model and reflect features of the real dispatch not reflected in the model.

In the end, it is seen that sensitivity analysis of simulation results is essential in assessing the conclusions that can be drawn. The approach of drawing inferences regarding competition based on comparisons between actual prices and those simulated in these simple models could produce substantial errors. The difference between the actual and simulated prices could arise from the real-world constraints omitted from the model in conjunction with purely competitive behavior, or the difference could arise from the exercise of market power by sellers that are able to raise prices because of constraints omitted from the model. The differences between the actual prices and those simulated by these kinds of models provides little information on the degree to which prices have been impacted by the exercise of market power, one simply cannot tell from these simulations. The error is larger than the effect being estimated.

II. CALIFORNIA SIMULATIONS

A. Simulation Methodology

A direct approach for identifying an exercise of market power would focus on the decisions of individual generators. Given observed market prices, known production capacities and costs, and actual production over a period of time, a significant exercise of market power would reveal repeated deviations from profit maximizing production schedules. Typically the deviations would appear as offering production that is below the profitable level given the prices, environmental restrictions, ramp rates, and output of ancillary services. With this necessary evidence, the analysis could turn to examination of particular explanations for these deviations, such as instructions from the system operator to deviate from the optimal production pattern, or would support the market power interpretation of the data.

A limitation of the direct approach from the standpoint of some market observers may be the need to acquire confidential data about production schedules, ramp rates, available capacity, and ancillary service supply and requirements that may not be found in public information. For example, absent complete information about the multi-product output of individual generating plants, it might be impossible to distinguish between reducing energy production to exercise market power versus supplying reserves to meet reliability requirements or comply with environmental laws or regulations.

If available, direct evaluation of the performance of generators would be the preferred approach. However, as an alternative, some observers have applied simulation models to indirectly test for the exercise of market power. If it were possible to obtain an adequate simulation of a competitive market outcome, without any exercise of market power but consistent with system resources and reliability requirements, the resulting simulated prices could be compared with the observed market prices. An exercise of market power would be consistent with a finding that market prices were significantly above the simulated competitive price. The simulation results would not in themselves identify who had exercised market power, but the price markup condition would support a finding that someone had exercised market power.

In order to apply the logic of the indirect simulation approach, it would be necessary to build a simulation model with enough of the essential detail of the electricity system to simulate the competitive level of prices given competitive bids. The detail would include network constraints, ramping rates, and many other characteristics within an optimization framework to replicate the decisions of economic dispatch.[7] The resulting effort would be data intensive. The simulation output would include different prices at different locations, with dynamic interactions among time periods. The result would be a dynamic multi-price simulation.

Experience with such models (e.g., GE-MAPS) indicates that the optimized output invariably ignores some of the constraints facing real system operators. Even with a good, or very good model, differences between simulated and real results arise because of simplifications in the model. Nevertheless, there is a long history of building and using such dynamic multi-price models to analyze a wide array of energy policy problems. In the typical application, the impact of simplifications in the model is addressed by comparing results between different simulation cases, thereby attempting to isolate the effects of the differences in the simulation cases and net out any bias in the simulation models. A different approach would be required in an application that compares a simulation case with real outcomes, for which the simplifications in the model could bias the results.

With the focus on market power problems, however, there has been a new approach to simulating the operations of the electricity system. This approach has been to go further in the direction of simplification of reality. This has resulted in the use of models that strip away most of the details of the electricity system. In particular, the new approach has been to ignore all the complications of the electric network to assume that all the market operates effectively at a single location. Further, these models ignore dynamics and assume that each electricity plant has complete flexibility to change its output in any hour based on the economics of price versus a variable cost in that hour, with no start up costs or minimum load effects.

With these simplifications, the resulting model views each hour as independent of all other hours of operation. Hence, there are no dynamic effects. The model is thus static and solved

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7 Rajesh Rajaraman and Fernando Alvarado, "[Dis]proving Market Power," January 24, 2002 (revised March 2, 2002)

separately for each hour. Furthermore, without separate treatment of different locations or products, the market outcome reduces to a single market price for energy. Hence, the resulting model is a static single-price simulation.

With these assumptions, the static single-price simulation requires data on plant capacities, incremental energy costs, and aggregate demand for energy and ancillary services. Given a rule for simulating outages and deratings either by randomly selecting available plants in each hour, or by derating the output of all plants using an average availability factor, the optimization model reduces to a single-stack analysis. The energy bids of the available plants are stacked from lowest to highest. Starting from the bottom with the cheapest, plants are dispatched until the combined output meets the aggregate load. The incremental cost of the most expensive plant dispatched determines the simulated competitive price. This analysis is repeated separately for each hour. Assuming that there is a single energy price in the real electricity market in each hour, this simulated price provides the competitive standard for comparison.

The argument for using a static single-price simulation stands on the premise that the errors induced by the simplifications are not significant compared to the price markups reflecting a difference between simulated competitive prices and the observed market prices. Given the long history of use of dynamic multi-price simulation models, applied with care and caution, this is a somewhat surprising assumption. Were it true, the industry must have some other explanation for the widespread practice over many years of investing in the more complicated models. Furthermore, the movement from comparison between different simulation cases to net out the modeling bias, to direct comparison of a simulation case with the real data, should raise a caution about the effect on the reliability of the estimates.

The purpose here is to address the assertion that the static single-price simulation model does not introduce errors as large or larger than the effect it is to estimate. Our previous papers have given many examples of the difficulty in accepting this position. Here we carry this work further by applying sensitivity analyses with a typical application of the static single-price methodology.

The resulting sensitivity analysis is especially important in trying to understand the nature of market power exercised in electricity systems. The usual argument for why the single stack optimization presents a special problem in the case of electricity emphasizes the tendency of the supply curve to rise rapidly at high levels of output near the capacity of the system. In this range, a small level of supply withholding to exercise market power could produce a large price increase. Unfortunately, this same feature means that small errors in the single stack model could produce large changes in the simulated price in this same range. To illustrate the significance of this fact, consider the supply curves shown in Figure 28.

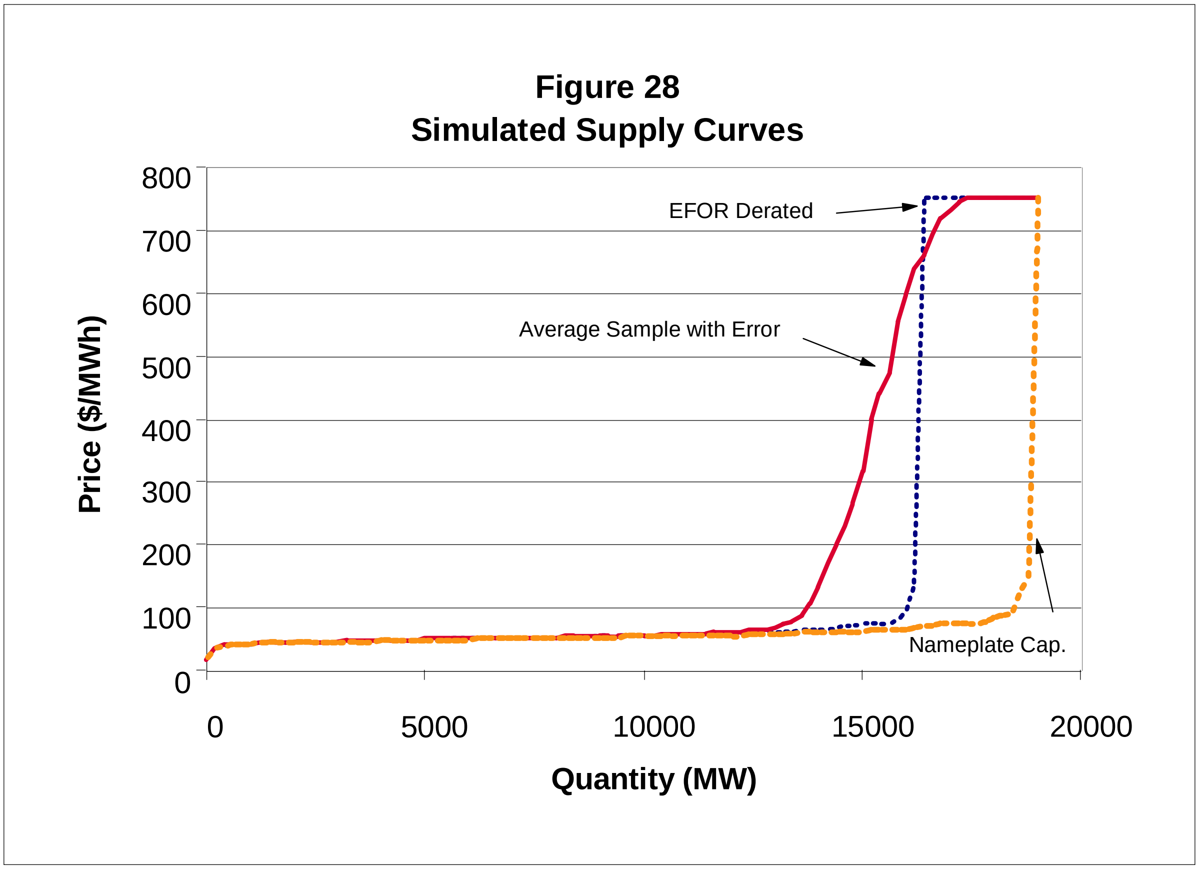

Figure 28 depicts the supply curves for thermal capacity for an illustrative case discussed below. The details of the particular case are not important for the illustration. The total nameplate capacity reduces to the derated supply curve to reflect equivalent forced outage rates (EFOR), in the same manner used in the Joskow-Kahn simulation model. Setting aside the difficulties in estimating costs and other elements, suppose that the simplifications in the static, single-price model that ignore dynamics, environmental limitations, greater stress on the plants, and so on, add a 5 percent chance that an individual plant is unavailable in any hour. This error could be addressed as an addition to the assumed outage rate. Using this higher effective rate, a Monte Carlo sampling produces an average supply curve subject to a $750 price cap. The result has the same properties often described as indicative of the exercise of market power. In particular, the markup between the average price curve and the "competitive" derated supply curve is virtually zero at low load levels, and the markup rises rapidly as load approaches the maximum of the derated supply curve. Using a dispatch profile from a June 2000 simulation, the average price is approximately $105 versus the "competitive" derated simulation of $59, for a markup of 44 percent. But we know that this difference is not a result of the exercise of market power, it is the result of competitive behavior but with a 5 percent difference in the real availability of plants compared to the static ideal. Concluding that this markup arises from an exercise of market power and not error in the model would require controlling for all the errors in the model well below this 5 percent level.

Hence, it is inherently difficult to separate the effect of errors in the model from the apparent exercise of market power. The illustration in Figure 28 suggests why this is true, and the detailed sensitivity analysis to follow examines the impact of several different changes in assumption that have similar effects.

B. Summary of Approach

Our previous examinations of the market power analyses for California addressed the many simplifications in the models used to simulate the competitive price level. Examples illustrated the potential impact of over-optimization by ignoring real constraints. However, the discussion did not go to the kind of systematic sensitivity analysis that would provide aggregate quantification of the magnitude of the problems. Since the force of our critique has been that a much more complicated dynamic simulation is required, with data that are not available in the public domain, it is not possible to substitute a better simulation with competing estimates of the competitive benchmark price. However, we have gone further here in doing sensitivity tests within the framework of the simplified methodology. The focus, therefore, is not on the best estimate of the competitive price but rather on the confidence interval for the best estimate and the extent to which the range includes or excludes the observed market prices.

Although studies have been undertaken of NEPOOL and PJM as well of California, we have chosen to undertake sensitivity analysis based on the California studies, in part because we are already familiar with a number of the data sources and because market prices reached much higher and more controversial levels in California. In particular we focus on the simulation results from Joskow and Kahn because they based their work on public information.[8] However, the results of Joskow and Kahn are qualitatively similar to those of other simulation studies of the California market. We attempted to provide a starting point for the sensitivity analysis by replicating the most recent Joskow and Kahn simulations, which use only publicly available data, and we have focused on June 2000 because of the large gap they found between actual and simulated prices during that month.[9] The Joskow-Kahn methodology has not always been fully described, however, and there are many important steps in the simulation for which their papers provide little guidance. In filling in these gaps we have attempted to utilize the data sources referred to by Joskow and Kahn, and to be conservative (choosing the alternative that would tend to result in lower simulated prices). This attempted replication of the Joskow-Kahn simulation yields an average June price of $85.28/MWh or $76.90/MWh if hourly prices are subjected to a $750/MW price cap.[10] These prices are noticeably higher than those reported by Joskow and

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8 Joskow and Kahn also provide a separate direct analysis addressing possible withholding by generating companies.

9 This analysis of a single month does not demonstrate that the prices prevailing in the WSCC during 2000 and 2001 can in all cases be explained by purely structural considerations. The purpose of the analysis is to demonstrate that the simplifications commonly made in simulating electricity prices with single-stack models introduce such a wide range of error in simulating market prices that the error is larger than the effect being estimated.

10 The simulation model used for this replication is or will be available at lecg.com (See practices/Electric Power, Oil & Gas/Research Papers & Testimony/California Electricity Markets). The posted model does not include proprietary Henwood data nor are the CEMS data appended.

Kahn ($67.23 with uncapped prices), but noticeably lower than actual prices. We have not explained the cause of the remaining differences, but they may arise from averaging across hours in the Joskow-Kahn simulation or differences in resolving the many methodological ambiguities that are described below. This discrepancy may be just a mistake on our part in understanding what was done in Joskow and Kahn, but it illustrates the importance of seemingly harmless approximations.

The second stage of the analysis is to use this replication to test the impact of alternative assumptions regarding reserve requirements, environmental constraints, start-up and minimum-load costs, outages, hydro power availability, and import elasticities. These start with the replication which serves as the basis of comparison. Hence, the sensitivity tests do not depend on the full resolution of the difficulties in repeating what Joskow and Kahn reported. This resulted in several hundred sensitivity cases**.** These cases are summarized in Section D. It is seen that essentially every case that accounts for actual California Independent System Operator (CAISO) reserve requirements produces simulated prices that are consistent with or above average actual prices.

C. Replication

The initial step in assessing the impact of alternative simulation methodology and assumptions is the replication of the Joskow-Kahn price simulations for the month of June 2000. This replication has three main elements: estimating CAISO load, estimating must-take generation, and dispatching imports and dispatchable generation to determine a simulated price.

1. Load

The starting point in the simulation of competitive prices is determination of the load that must be met by generation resources. Three aspects of the definition of load merit discussion: reserves, hourly aggregation and actual load.

First, Joskow and Kahn add 10 percent to actual load in Joskow-Kahn March 2001[11] to account for capacity required to provide reserves and regulation, but reduce this in Joskow-Kahn July 2001 and February 2002[12] to a 3 percent allowance for upward regulation only. Although the actual hour-by-hour ancillary service requirement depends on some factors that are not public, the 3 percent alternative is too low. The assumption in their recent papers is readily replicated, and the sensitivity analysis will examine the degree to which the results are sensitive to the assumption that it is not necessary for the CAISO to maintain contingency reserves or comply with North American Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) reliability standards.

Second, the Joskow-Kahn March 2001 simulation was based on 10 periods per month, while Joskow-Kahn July 2001 and Joskow-Kahn February 2002 were based on 100 periods per month.

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[11] Joskow-Kahn March 2001, p. 11.

[12] Joskow-Kahn July 2001, p. 7-8 and Joskow-Kahn February 2002, p. 13.

Disaggregation from 10 to100 hours in the Joskow-Kahn July 2001 study materially raised the simulated prices.[13] We have not attempted to aggregate the load data from 720 hours. There is no apparent benefit to such aggregation and no computational need to reduce the number of hours. Moreover, because aggregated load data cannot be chronological,[14] simulations based on load aggregated across hours are intrinsically problematic because they cannot reflect the operation of the actual generation and transmission system, which must operate chronologically. All of our simulations are therefore based on 720 hourly observations for June 2000, and this allows us to make some calculations that address the chronological pattern of output.

Third, Joskow and Kahn do not describe some of the details of how they measure load for their simulations.[15] The CAISO posts data on real-time system deliveries to the distribution system,[16] but this does not equal total transmission system load because it does not include transmission system losses.[17] Moreover, actual system deliveries to the distribution system do not include load that has been dispatched off in real-time on a price or reliability basis.[18] One method of approximating total actual system load is to add estimated hour ahead losses[19] to CAISO data for real-time deliveries to the distribution system. We assume that Joskow and Kahn included estimated losses in load in this manner, although as noted above their method of estimating real-time load is not clear from their papers. This methodology does not give a completely accurate measure of real-time load because differences in the level and location of assumed and actual load and generation would affect losses but we assume that these differences are second order effects and thus that this assumption provides a reasonable approximation of transmission system load.[20]

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[13] See Joskow-Kahn July 2001, pp. 12-13. It should be noted that the sensitivity results that were reported for load modeling in the July paper contained anomalies (see Harvey-Hogan December 2001, pp. 43-45). These anomalies have not been explained in subsequent papers and it may be that none of the simulated prices reported in Joskow-Kahn July 2001 are accurate.

[14] By chronological, we mean that in real operations, hour ending 24 on June 17 (real-time price of $84.42) followed hour ending 23 (real-time price of $3.20), which followed hour ending 22 (real-time price of $95.21).

[15] Joskow-Kahn February 2002, for example, refers to "hourly demand" and "mean load" without further explanation.

[16] Historical data through August 31, 2000 has been archived by the CAISO in the "Chronicles" section of its OASIS website. Real-time data on deliveries to the distribution system is found under the "ISO Actual System Load" variable at www.CAISO.com/marketops/OASIS/pubmkt2.html.

[17] Similarly, hour-ahead schedules do not include losses.

[18] Joskow-Kahn July 2001 contains a brief discussion of interruptible load (p. 10) but it does not clarify whether it is included in their measure of load.

[19] Historical data on estimated hour-ahead losses through August 31, 2000 , are found in the "Chronicles" section of the CAISO OASIS website under the "Hour Ahead Company Losses" variable at www.CAISO.com/marketops/OASIS/pubmkt2.html.

[20] An alternative approach to estimating load would be to measure it as the sum of hour ahead schedules plus BEEP stack dispatch instructions. Hour-ahead schedules may be either greater or less than actual output, however. This approach would not capture load met with real-time RMR dispatch instructions or out-of-market calls, or the impact of over- or undergeneration relative to these schedules.

This measure of demand would not include load that was dispatched down in real time. Load dispatched down in the Balancing Energy and Ex-Post Pricing (BEEP) stack appears to be of two types. First, pump storage units would be scheduled to operate, consuming energy, in off-peak periods and their consumption could be dispatched down in response to high real-time prices. Second, interruptible loads might be interrupted by the CAISO (through the individual utilities) in response to emergency conditions. It is not clear from the Joskow-Kahn papers how these loads were treated in their simulation.[21] In estimating the real-time demand against which generation is dispatched, we have not included in demand pumped storage load that was dispatched down in real-time (this load was interrupted at a price less than or equal to the actual real-time prices so excluding it from demand is conservative) but we have included in demand load that was interrupted by the distribution companies to maintain reliability (because this interruption reflected a supply shortage at the market-clearing price). For example, the highest hourly load during June was 44,417 MW on June 14, 2000, hour ending 16:00. This load was derived by adding transmission system withdrawals of 43,447 MW, plus estimated losses of 900 MW, plus real-time beep stack load curtailments of 70 MW. This total load was then increased by 3 percent to 45,750 MW to account for capacity required to provide up-regulation.

2. Must-Take Generation

The first type of generation scheduled to meet load in the Joskow-Kahn simulation is must take and other non-dispatchable generation including nuclear, wind, qualifying facility (QF), geothermal, hydro, solar, and biomass output.

Nuclear. Joskow-Kahn July 2001 and Joskow-Kahn January 2002 assume that all nuclear plants operated at capacity, which would be 4,358.4 MW during June 2000. This is virtually identical to the average output reported on the Energy Information Administration (EIA) form 759, of 4,387.96 MW. To be conservative, we have used the average EIA output of 4387.96 MW in the base case simulations.

Hydro. The second type of non-dispatchable generation included in the Joskow-Kahn simulations is hydro generation, including pumped storage. At least some of this generation is dispatched on a price basis in the real world, but it is all treated as price taking in the Joskow-Kahn simulations.[22] In determining the level of hydro output and allocating this output across hours, Joskow and Kahn state that they calculated an average hourly hydro energy available for each month based on the EIA-759 data for units dispatched by the CAISO,[23] and then assumed that hydro energy output was 60 percent of this average off peak and 8,000 MW on peak in Joskow-Kahn March 2000 and 8,500 on peak in the other simulations.[24]

We applied the methodology described by Joskow-Kahn to the EIA 759 data for June 2000, excluding the generation of the Los Angeles Department of Water and Power (LADWP),

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[21] See, for example, Joskow-Kahn February 2002, p. 13.

[22] Joskow-Kahn March 2001, pp. 11-12; Joskow-Kahn July 2001, p. 9; and Joskow-Kahn February 2002, p. 13.

[23] Joskow-Kahn March 2001, p. 11; and Joskow-Kahn February 2002, p. 13.

[24] Joskow-Kahn March 2001, p. 11; Joskow-Kahn July 2001, p. 9; and Joskow-Kahn February 2002, p. 13.

Imperial Irrigation District (IID), and PacifiCorp and dividing by 720.[25] The remaining hydro generation averaged 5,807 MW/hour.[26] The allocation of this output to hours by load level pursuant to the Joskow-Kahn methodology is shown in Table 1 below.

[25] We have been able to replicate the illustrative calculations they provide for July 2000 in Joskow-Kahn March 2001, by adding up the EIA 759 output for California generators other than LADWP, IID, PacifiCorp *and SMUD*, (Sacramento Municipal Utility District) and dividing by 720. It is not clear if and why the SMUD output was apparently excluded from the calculation of hydro supply as the SMUD units for which data is reported to the EIA are included in the list of CAISO units. SMUD is not mentioned as excluded in Joskow-Kahn July 2001, p. 9. In addition since there are 31 days in July, the data should have been divided by 744 hours, not 720. If these figures were used in the Joskow-Kahn simulation for July 2001, average hydro energy was understated by about 225 MW by the exclusion of SMUD and overstated by about 170 MW/hour by dividing by 720 hours. Joskow and Kahn do not repeat the illustrative calculation of hydro supply in the later versions of the paper, so it is unclear if there are similar anomalies in the hydro output assumed in later papers.

[26] The Joskow-Kahn methodology has several elements that potentially misstate the available hydro generated energy. First, it is not clear that all of the EIA units whose output they include are actually within the CAISO control area. We attempted to match EIA reports to CAISO generators, and in addition to the IID, PacifiCorp and LADWP identified 420.3 MW of capacity, and 224.67 average MWh of energy in the EIA data that we could not match with units listed as within the CAISO control area. Average hydro output within the CAISO control area is therefore potentially overstated by 224.67 MWh. Conversely, small hydro units do not have to submit the EIA form and there were units with an aggregate capacity of 327.85 MW listed by the CAISO, for which we could not match EIA forms. If these resources were operating during the summer of 2000, the Joskow-Kahn calculations would have understated actual hydro generation during the month.

Table 1 HOURLY ALLOCATION OF JUNE 2000 HYDROELECTRIC OUTPUT	
	EIA-759 Excluding LADWP, Imperial and PacifiCorp
Total Monthly Output (MW/h)[1]	4,181,283
Average Hourly Output (MW/h)[2]	5,807
Output Allocated to Load Decile (MW/h)[3]	
Decile 1	3,484
Decile 2	3,484
Decile 3	3,484
Decile 4	3,484
Decile 5	3,484
Decile 6	6,651
Decile 7	8,500
Decile 8	8,500
Decile 9	8,500
Decile 10	8,500

1 Sum of CAISO hydro output by unit for month of June 2000 from EIA-759, excluding LADWP, Imperial Irrigation and PacifiCorp units.

2 Average hourly output equals total monthly output divided by 720 hours.

3 Output allocated to load decile. Each decile is allocated a minimum of 60 percent of the average hourly output of CAISO hydro units. The highest deciles are allocated additional energy, up to a maximum of 8,500 MW, such that the average energy allocated to each decile equals average hourly output. Joskow and Kahn use a maximum of 8,000 MW in January 2001 and 8,500 MW in their July 2001 and February 2002 papers. 8,500 MW is utilized to replicate their most recent paper.

Wind. Joskow-Kahn March 2001 apparently assumed that wind generation was fully available at capacity in all hours, while the later papers assumed only a 20 percent capacity factor for wind generation.[27] This 20 percent capacity factor would amount to 375 MW during June 2000. Our replication makes the same assumption.[28]

Geothermal. Joskow and Kahn explained in their July 2001 paper that they had derated geothermal capacity to reflect energy limits in both the March 2001 and July 2001 studies, but they did not state what factor was used for this derating.[29] We assume that Joskow and Kahn

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27 Joskow-Kahn July 2001, p. 11 and Joskow-Kahn February 2002, p. 14.

28 We also attempted to assess the reasonableness of this assumption by analyzing the EIA reports for the wind generators. We have attempted to match all of the EIA reports to wind generation units in the CAISO database. Based on this matching, the average output reported in the EIA data was 17 to 25 percent of the capacity reported in the CAISO data, the range arising from uncertainty over whether the units of one large plant have been correctly matched between the EIA and CAISO data. It should be noted that the capacity reported in the CAISO data appears to sometimes be much lower than the capacity reported to the EIA.

29 Joskow-Kahn July 2001, p. 11. There is no mention of geothermal output assumptions in the January 2002 paper

used a derating factor consistent with the output of the geothermal units reported to the EIA[30] (consistent with their method for calculating energy limits for hydro generation) for June 2000, which was 73.5 percent. We have also applied this capacity factor to the capacity of the geothermal units in the CAISO data base for which no EIA data was available. This procedure may be conservative because some of the units that did not file EIA data may not have done so because they did not operate during the month.[31] In addition, the CAISO capacity data utilized by Joskow and Kahn lists some geothermal units for which no capacity value was provided by the CAISO.[32] None of the Joskow-Kahn papers describes what methodology was applied in this circumstance. Since we have been able to match these units to units filing EIA reports, we have added the net output reported to the EIA for these units to the 658.81 MW output estimated for the units having CAISO capacity data. The result is actual geothermal output reported to the EIA of 976.19 MW/hour and an assumed output of an additional 269.67 MW/hour for units not reporting to the EIA based on the estimated derating factor for a total of 1,245.86 MW/hour.

Table 2
GEOTHERMAL OUTPUT AND CAPACITY DATA

	EIA Output (MW/h)	CAISO Capacity (MW)	Estimated Output (MW/h)
Matched Units	658.81	895.77	658.81
No CAISO Capacity	317.38	NA	317.38
Not Matched or No EIA Output Data	NA	366.90	269.67
Total	976.19	1,262.67	1,245.86

Solar. Joskow and Kahn do not discuss how they modeled the output of solar generation. The Henwood data Joskow-Kahn used for capacity in their March paper assumes full solar output during the day, 60 percent solar output in shoulder hours and none at night. If this temporal allocation is applied to the solar units for which EIA output data are available, the day-time hour output averages 106.27 percent of the CAISO capacity during June 2000. For the purpose of replicating the Joskow-Kahn simulation, we have applied this same capacity factor to the solar units for which we have CAISO capacity data but no EIA output data. This implies a total daytime output from the solar units of 402.75 MW during June 2000. See Table 3.

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30 EIA Form 900.

31 It should be noted that the CAISO capacity data used by Joskow and Kahn for June 2000 was posted in early 2001, so may not represent actual June 2000 capacity.

32 These are Cosco Finance Partners (Navy I); Cosco Power Developers (Navy II); Herber Geothermal Company; and Salton Sea Power Generation L.P. (#1, 2, 3, 5).

Table 3 SOLAR OUTPUT AND CAPACITY DATA			
	EIA Output (MW/h)	**CAISO Capacity (MW)**	**Estimated Output (MW/ Daylight Hour)**
Matched Units	80.77	160.00	170.04
Not Matched or No EIA Output Data	NA	218.97	232.71
Total	80.77	378.97	402.75

Biomass. It was possible to match all of the EIA biomass generation reports to biomass units listed by the CAISO. June 2000 output averaged 50.3 percent of CAISO capacity for these units. This 50.3 percent capacity factor was applied to the other 827.94 MW of capacity listed by the CAISO for which an EIA report could not be located, for total biomass output of 524.55 MW. See Table 4.

Table 4 BIOMASS OUTPUT AND CAPACITY DATA			
	EIA Output (MW/h)	**CAISO Capacity (MW)**	**Estimated Output (MW/h)**
Matched Units	108.10	215.10	108.10
Not Matched or No EIA Output Data	NA	827.94	416.45
Total	108.10	1,043.04	524.55

QF. Finally, Joskow and Kahn do not discuss how they determined the simulated output of thermal QF generations (mostly cogeneration). Many of the larger QF generators file EIA 759 reports, so it was possible to match the actual average June output of these units to their CAISO capacity. The calculated capacity factor averaged 85.4 percent for the Cogen units that were matched. The CAISO capacity list included an additional 2,508.21 MW of capacity that could not be matched with units on the EIA list. Many of the unmatched units are sufficiently small to not file an EIA report, but some may actually be other names for units included in the EIA data (which would tend to cause an overstated capacity factor). It was assumed that the unmatched units had the same average capacity factor as that calculated for the units that it was possible to match; see Table 5.

Table 5 THERMAL QF OUTPUT AND CAPACITY			
	EIA Output (MW/h)	**CAISO Capacity (MW)**	**Estimated Output (MW/h)**
Matched Units	3,015.55	3,529.00	3,015.55
Not Matched or No EIA Output Data	NA	2,508.21	2,142.01
Total	3,015.55	6,037.21	5,157.56

Overall, therefore, the Cogen units are treated as having an average output of 5,157.56 MW in the simulation. Joskow and Kahn did not mention applying any generation profile to this average output level so neither have we. Many of the QF generators were related to hosts that operate 24 hours a day, 7 days a week (such as enhanced oil recovery projects and refineries) but others may have shut down off-peak, while others may have delivered more energy off-peak due to reduced electrical consumption by the host. We have no basis for assessing whether the assumption of a flat QF profile is conservative.

3. Dispatchable Generation

The dispatchable generation included in the Joskow Kahn simulation includes imports, non-utility generation (NUG) thermal units, and utility thermal generation.

Imports. The first two sets of Joskow-Kahn simulation results measured import supply as equal to actual scheduled imports plus actual BEEP stack imports, and then adjusted this supply up or down based on the simulated price and an assumed import supply elasticity of .33.[33] The most recent Joskow-Kahn simulation results refer to "line flows that we aggregate to construct our measure of net imports."[34] This is inconsistent with the discussion in the July paper and we assume that the February paper is also based on scheduled imports plus BEEP stack imports.

One peculiarity of the formula apparently employed by Joskow and Kahn is that it relates real-time imports to day-ahead prices. This formula results in implausible levels of simulated imports whenever day-ahead and real-time prices are materially different. For example, the real-time price for hour ending 11 on June 16 was $41.67, while the unconstrained day-ahead Power Exchange (PX) price was $360.86, while real-time imports (hour ahead schedules plus BEEP stack) were 5,180 MW. At a simulated price of $41.67, the Joskow-Kahn import scaling formula would reduce imports from 5,810 MW to 2,829 MW. This would prevent the simulation from replicating the real-time price (because the simulated imports would be lower than the actual imports) but the actual real-time load was low, so the day-ahead price would also not be

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33 Joskow-Kahn July 2001, p. 11-12. Joskow-Kahn March 2000 states that the import data used was CAISO line flow data, but the July 2001 paper indicates that this was not actually the case (p.11).

34 Joskow-Kahn February 2002, p. 15.

replicated. To avoid these kinds of anomalies for the sensitivity tests, we have also applied their import formula to real-time imports based on real-time prices. Thus,

$$\text{Simulated Imports} = \left(\frac{\text{Simulated Price}}{\text{Real-Time Price}}\right)^{.33} \bullet \text{ Real-Time Imports.}$$

With this formula, if the simulated price were the same as the actual real-time price, the simulated imports would be the same as actual imports. This formula has been used throughout the sensitivity analysis. This formula could also yield anomalous values, however, if the real-time price were zero or negative so we have set simulated imports equal to actual imports in these circumstances. In hours in which inter-zonal congestion caused the SP-15 and NP-15 real-time prices to differ, the average of the SP-15 and NP-15 price was used as the scaling factor.[35] As in Joskow and Kahn, no transmission constraints on imports are modeled so it is possible that if the simulated price exceeds the actual price, the simulated level of imports could be infeasible in the actual dispatch. We do not expect that this consideration would be material in June 2000 as imports were below historical levels and transmission constraints on imports were rarely binding.

Thermal Generators. All thermal generators are dispatched in the Joskow-Kahn simulation based on their fuel, emissions, and variable O&M costs. For most generators, the fuel cost is the product of the Henwood full load heat rate and an average monthly gas price. As Joskow and Kahn note, although Mohave is physically located in Nevada it is modeled by the CAISO as if it were located within the CAISO control area and energy supplied from Mohave to entities not located within the CAISO is accounted for by the CAISO as exports.[36] It is not entirely clear to us whether Joskow-Kahn treated all of the Mohave unit as being internal to the ISO or only Southern California Edison's (SCE) share of the unit.[37] Our assessment of the various CAISO information is that all Mohave output is treated as internal to the CAISO control area[38] and we have taken this approach in our simulations (i.e., the entire output of Mohave, not just the SCE share, has been included in CAISO supply). In the case of Mohave, the fuel cost was presumably based on coal prices, but Joskow and Kahn do not indicate what coal price was used to dispatch

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35 It would be preferable to simulate imports based on zonal prices, but this has not been possible because we lack data on real-time consumption by zone.

36 See “Rebuttal Testimony of A. Deane Lyon on Behalf of the California Independent System Operator Corporation,” FERC Docket No. ER01-313-000, et al., filed September 27, 2001 and “Prepared Supplemental Direct Testimony of Mark R. Minick on Behalf of Southern California Edison Company,” FERC Docket No. ER-01-313-000, et al., filed June 25, 2001.

37 Joskow-Kahn February 2002, p. 15, states that “BBW include production from SCE’s share of Mohave in their measure of in-state must-take generation. We include Mohave’s generation in imports because its output is included in the flows that we aggregate to construct our measure of net imports.” This is confusing because as noted above this methodology for determining imports is inconsistent with the discussion in their July paper and appears to have been erroneously copied from the March 2001 paper. Moreover, if they did include Mohave in instate generation, it is unclear whether they added the full Mohave capacity or only the SCE share.

38 Thus, the output share of the non-SCE Mohave owners would show up as CAISO exports if it were delivered to meet the load of the non-SCE Mohave owners.

Mohave in their model. We have treated Mohave in the base case as always in merit with a 7 percent EFOR rating, providing an output of 1,450.76 MW in every hour.

The EIA data used by Joskow and Kahn to determine nuclear, hydro and presumably other outputs indicates that Mohave actually had a capacity factor of only 80.8 percent during June. It can be seen from the EPA's Continuous Emissions Monitoring System (CEMS) data for Mohave that the 80.8 utilization factor was due to an apparent inability of Mohave to operate at the capacity reported in the CAISO 2001 data file and due to several forced outages and deratings, including a substantial reduction in output during the period of high prices on June 14. By using the actual output of the utility nuclear plants (which operated at capacity during June) and the theoretical outage adjusted capacity of the utility coal plants (which operated at substantially less than their theoretical outage adjusted capacity during June) the Joskow-Kahn simulations overstate utility output in the simulation compared to the real dispatch.

A number of units are identified in the Henwood database and EIA data as oil-fired.[39] LA Harbor June 2000 spot prices were used for #2 and jet prices. San Francisco area fuel costs were increased by 1¢/gallon over the LA spot price as a rough approximation of transportation costs, while San Diego costs were increased by 1/2¢/gallon. We have not attempted to assess what additional handling costs and losses are incurred on petroleum fuels. All petroleum prices were increased 6 percent for taxes.

The emissions cost used by Joskow and Kahn for units located in the Southern California Air Quality Management District (SCAQMD) only was the Henwood Energy Services Inc. (HESI) or SCE emissions rate times the assumed Regional Clean Air Initiatives Market (RECLAIM) NOx Trading Credit (RTC) allowance cost. We do not have access to the SCE data utilized by Joskow and Kahn so we have based our replication solely upon the HESI emissions data.[40] We have identified the units subject to SCAQMD emissions rules using the Henwood data.[41]

Joskow and Kahn also stated that they used Henwood data on variable O&M costs for the thermal units. We have also used this approach. The Henwood variable O&M costs in the Henwood database are tied to 1994 or 1996 costs and need to be escalated using the CPI per the Henwood escalation factor to reflect year 2000 costs. Joskow and Kahn do not discuss this, but we assume that these costs were escalated using the Henwood methodology in their simulations. We used the CPI-U[42] to escalate these costs to 2000 dollars. Finally, the output of all of the dispatchable thermal units was derated by Joskow and Kahn based on forced outage rates.[43]

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39 Joskow and Kahn do not explain what fuel costs they use for oil-fired units. There were also a number of units identified as oil-fired in the Henwood data that the EIA data indicate were gas- or dual-fueled. We assume that dual-fueled units would have been burning gas in June 2000, although this would likely not be the case during the winter months. After reconciling the Henwood and EIA data on fuel type, only the GTs at Oakland (#2), South Bay (jet), Humboldt Bay (#2), Hunters Point (#2) and Potrero (#2) were treated as oil-fired.

40 The HESI emissions data are consistent with NOx emissions rates found in the EPA CEMS data.

41 Henwood assigns thermal generators to emissions basins using the “Emission Basin ID” variable. A value of 1899037923 identifies units located in SCAQMD.

42 The CPI-U data are available at the Bureau of Labor Statistics’ website at www.bls.gov.

43 Joskow-Kahn March 2001, p. 12-13; Joskow-Kahn July 2001, p.7; and Joskow-Kahn February 2002, p. 14.

Joskow and Kahn clearly state that they are using the EFOR outage rate in their February 2002 paper; they refer to Henwood outage rates in earlier papers but it is less clear which outage rate they utilized in the earlier papers.

Moreover, there is no forced outage rate data in the Henwood database for many of the thermal units relevant to the Joskow-Kahn analysis. Joskow and Kahn do not explain what assumption they employed for such missing data in the earlier papers that referenced Henwood outage data. The February 2002 paper specifically refers to the EFOR outage rate,[44] but does not refer to the Henwood database but instead to raw NERC average outage rates for different types of units by size and fuel (that is, the outage rates are not broken down by unit age, steam vs combined cycle or base load vs cycling use). It appears likely to us that Joskow and Kahn applied the NERC averages to the California units based on their size and fuel type, although this is not explicitly stated. We have applied this approach in attempting to replicate their analysis.

Finally, there are several units owned by PG&E, agencies or other entities that were in the process of being mothballed, being brought out of mothballs or for other reasons were not available at all during the month of June 2000 or were available only for a short period. In particular, PG&E's Hunter's Point 4 unit tripped on June 7, and was not available for the remainder of the month.[45] Joskow and Kahn stated that the Hunters Point steam units were excluded from their July simulations, but there is no mention of how they were treated in the February paper. Similarly, Thermoecotek's Highgrove units had been mothballed and did not operate at all during June 2000,[46] and its San Bernardino units were only brought out of retirement in time to become available on June 20 (Unit 2) and June 21 (Unit 1).[47] These units are included in the simulation here only for the days they were actually available in the real dispatch.

4. Simulation Results

The base-case replication of the Joskow-Kahn simulation for June 2000 derived an average monthly price of \$85.28 at a \$10/pound NOx cost with real-time imports calibrated against day-ahead prices, which is noticeably higher than the \$67.23 figure reported in Joskow-Kahn February 2002. The methodology employed in Joskow-Kahn February 2002 apparently schedules imports to clear the market, regardless of whether resulting simulated price is above

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44 The NERC EFOR rate is defined to include the impact of both forced outages and deratings.

45 EPA CEMS data. The status of Hunters Point 2 and 3 is not clear. No CEMS MW output data were reported for these units and they have a zero capacity in the April 2001 CAISO capacity data utilized by Joskow and Kahn. Discussions with EPA clarified that PG&E reported steam load for units identified as Hunters Point 3, 5 and 6, but no MW output. The output of Hunters Point 4 appears to be reported as Hunters Point 7 in the CEMS output. Other information indicates that these units have been mothballed but the timing is unclear. The output reported on the EIA form 759 for June 2000, however, suggests that Units 2 and 3 may have been operating for all or part of that month so they have been included in the simulation based on their EIA capacity.

46 EPA CEMS data, EIA form 900.

47 EPA CEMS data.

the prevailing price cap.[48] Because this approach has the potential to lead to extremely high hourly prices in shortages that might materially impact the simulated monthly average prices, hindering meaningful comparisons with actual prices, we have calculated the monthly averages both with and without a $750 cap on the simulated prices. With the $750 price cap applied to the simulation results, the average June price in the base case simulation falls to $76.90. Actual prices ranged from $111.48 (the average of the lowest INC price on SP-15 in each hour)[49] to $131.55 (the NP-15 real-time price).

As noted, we also reran the base case simulation model calibrating real-time imports against real-time prices and these results are also portrayed in Table 6. These simulated prices are about $6/MWh higher than if real-time imports are calibrated against day-ahead prices. In examining the simulation results, it appears that calibrating real-time imports against day-ahead prices tends to depress simulated prices relative to real-time on the days on which real-time prices greatly exceeded day-ahead prices, because more imports are assumed to be available at a lower price than was actually the case on such a tight supply day. Conversely, on days on which real-time prices were much lower than day-ahead prices, calibrating real-time imports against day-ahead prices tends to reduce simulated import supply but this appears to have little impact on simulated prices because demand is low.

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[48] Joskow-Kahn February 2002, p. 15, state "We rely upon imports to clear the market when in-state fossil supply is exhausted. Because this will occasionally require more net imports than what was actually observed, our procedure will raise their price substantially when this is required. These prices will be higher than the ISO price caps in place during the summer. We interpret these cases as corresponding to the ISO's purchase of Out of Market (OOM) energy."

[49] Comparisons based on the lowest INC price isolate the extent to which the hourly price is due to sustained conditions as opposed to intra-hour ramping constraints and load peaks that are not included in an hourly simulation model.

Table 6 JUNE 2000 PRICES			
	ISO	**SP-15**	**NP-15**
PX Prices Actual		116.85	125.73
PX Prices Unconstrained	120.20		
ISO-Real-Time-Hourly		121.95	131.55
ISO-Real-Time-Lowest INC[1]		111.48	117.30
Joskow-Kahn (uncapped)			
March 2001	62.60		
July 2001 10-Load Slices	53.98		
July 2001 100-Load Slices	74.03		
February 2002 100-Load Slices	67.23		
Replication 720 Load Slices			
Uncapped Prices			
Imports – PX Price	85.28		
Imports – Real-Time Price	91.97		
Capped Prices			
Imports – PX Price	76.90		
Imports – Real-Time Price	82.63		

[1] Lowest 10-minute interval price in hour.

The noticeable differences between our base case simulation results and those reported by Joskow-Kahn indicate that we must have applied different methods than they in resolving the various methodological ambiguities we noted in the preceding sections of this paper. In our view, we have resolved these ambiguities in a reasonable and conservative manner and applied the spirit, if apparently not the letter, of the methodology described by Joskow and Kahn. We therefore have not attempted to mine the data to determine what differences in assumptions or methodology gave rise to the results they reported (which would in any case be extremely difficult to accomplish without access to their data and model). The apparent sensitivity of the simulated prices to seemingly innocuous differences in assumptions underlines the need for sensitivity analyses and replication. The several Joskow-Kahn implementations of the single-price simulation methodology produce a range of average prices from $54 to $74, suggesting the difficulties even when the methodology is well known. Here our attempt at independent replication adds almost 50 percent to the range of estimates. It is reasonable to infer that these results give a rough estimate of the error inherent even within the simplified framework of the single-price simulation methodology. The additional variance that follow from the simplifying assumptions of the methodology would be harder to estimate, but a range of sensitivity tests could indicate how matters like different reserve requirements or generation ramping could affect the outcome.

Before turning to the sensitivity analysis, however, it is useful to use these simulation results to illustrate the impact of some of the concerns we have previously noted with regard to the Joskow-Kahn simulation methodology.

We have previously observed that the Joskow-Kahn, BB&W and MSC simulations all fail to take account of start-up and minimum load costs in developing a hypothetical "competitive supply" curve and thus overstate the output that would be available at a given price in a competitive market.[50] In addition, we have shown that if units were dispatched on a non-chronological basis against actual prices based on their full load incremental heat rates per Klein,[51] that a number of high cost units would be dispatched to operate in a chronological pattern that would not have been economic in the real situation.[52] This is again the case in the base case simulation.

Of the 13 high cost LA Basin units we discussed in previous papers, seven were dispatched in the base case simulation for one or more hours on days during the period June 1-12, with a total output of 40,863 MW over these days or 3,405 MW/day.[53] This output pattern would be profitable if evaluated without regard to start-up costs or the need of the unit to remain on line but is not necessarily profitable if real-world costs and operating constraints are taken into account. Table 8 reports the profitability of operating these units to meet load on these days, if they had to remain on line over the remainder of the day at minimum load, evaluated at simulated energy prices, with no capacity derating. It can be seen in Table 8 that only El Segundo 3 on June 9 would have been profitable to operate in this manner at the simulated

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50 Harvey-Hogan October 2000, pp. 38-39, Harvey-Hogan April 2001, pp. 25-33, and Harvey-Hogan December 2001, pp. 33-35.

51 Joel B. Klein, "The Use of Heat Rates in Production Cost Modeling and Market Modeling," April 17, 1998.

52 Harvey-Hogan April 2001, pp. 25-33; and Harvey-Hogan December 2001, pp. 3-33.

53 Fewer units are dispatched on this basis than were dispatched against real-world prices in our December 2001 paper for two reasons. First, the Henwood full load heat rates used in the simulation are materially higher than the Klein heat rates on which our December paper was based. Second, the simulated prices are less variable day-to-day and hour-to-hour than actual prices.

Table 7

Simulated Daily Output of Select Units (Using Derated Capacities)

Units are fully dispatched if market price is greater than or equal to unit cost.

Date	Alamitos 1	Alamitos 2	Alamitos 3	Alamitos 4	El Segundo 1	El Segundo 2	El Segundo 3	Etiwanda 1	Etiwanda 2	Etiwanda 3	Etiwanda 4	Redondo Beach 5	Redondo Beach 6	Total Daily Output
6/1/2000	-	-	-	-	-	-	1,542	-	-	-	-	-	-	1,541.6
6/2/2000	-	-	-	-	-	-	1,233	-	-	-	-	-	-	1,233.3
6/3/2000	-	-	-	-	-	-	1,233	-	-	-	-	-	-	1,233.3
6/4/2000	-	-	-	-	-	-	308	-	-	-	-	-	-	308.3
6/5/2000	-	-	-	-	-	-	1,542	-	-	-	-	-	-	1,541.6
6/6/2000	-	-	589	586	-	-	3,392	-	-	586	293	-	-	5,444.6
6/7/2000	-	-	295	586	-	-	3,392	-	-	293	293	-	-	4,857.2
6/8/2000	-	-	1,178	1,171	-	-	3,700	-	-	878	293	-	-	7,220.4
6/9/2000	-	-	1,768	1,757	157	-	3,392	-	-	1,171	878	157	-	9,279.1
6/10/2000	-	-	-	-	-	-	3,083	-	-	-	-	-	-	3,083.2
6/11/2000	-	-	-	-	-	-	308	-	-	-	-	-	-	308.3
6/12/2000	-	-	589	586	-	-	2,467	-	-	586	586	-	-	4,812.4
6/13/2000	1,074	1,267	3,241	3,220	1,256	1,177	3,700	846	841	2,928	2,635	1,256	1,259	24,698.1
6/14/2000	1,687	1,743	3,830	3,806	1,727	1,618	4,625	1,329	1,321	3,806	3,806	1,727	1,731	32,754.9
6/15/2000	767	950	2,357	2,342	942	736	3,700	604	601	2,342	2,342	942	944	19,568.4
6/16/2000	-	-	1,473	1,464	-	-	3,392	-	-	1,171	878	-	-	8,377.7
6/17/2000	-	-	-	-	-	-	308	-	-	-	-	-	-	308.3
6/18/2000	-	-	-	-	-	-	308	-	-	-	-	-	-	308.3
6/19/2000	-	158	884	878	314	147	1,850	-	-	586	586	157	157	5,716.9
6/20/2000	-	317	1,473	1,464	628	147	3,392	-	-	1,171	1,171	314	157	10,233.6
6/21/2000	614	792	2,357	2,342	785	736	3,392	483	601	2,049	2,049	785	787	17,770.6
6/22/2000	307	317	1,768	1,757	314	294	2,775	121	240	1,757	1,171	314	315	11,448.2
6/23/2000	-	-	295	878	-	-	3,083	-	-	-	-	-	-	4,256.1
6/24/2000	-	-	-	-	-	-	308	-	-	-	-	-	-	308.3
6/25/2000	-	-	-	-	-	-	617	-	-	-	-	-	-	616.6
6/26/2000	1,074	1,267	3,535	3,513	1,413	1,177	4,008	846	961	3,513	3,513	1,256	1,259	27,334.7
6/27/2000	1,534	1,743	3,535	3,513	1,727	1,471	4,625	1,208	1,201	3,513	3,513	1,727	1,731	31,040.6
6/28/2000	1,380	1,426	3,535	3,513	1,570	1,324	4,625	1,087	1,081	3,513	3,220	1,570	1,416	29,260.9
6/29/2000	1,074	1,267	3,241	3,513	1,256	1,030	4,625	846	841	2,928	2,928	1,256	1,259	26,061.5
6/30/2000	153	475	1,473	1,464	471	147	3,700	121	120	1,464	1,464	471	315	11,837.5

Table 8

Unit Profitability Analysis: Energy Revenues from Base Case Simulation, Prices Capped at $750, Output Capped at Non-Derated Capacity, No AS Revenues

Date	Alamitos 1	Alamitos 2	Alamitos 3	Alamitos 4	El Segundo 1	El Segundo 2	El Segundo 3	El Segundo 4	Etiwanda 1	Etiwanda 2	Etiwanda 3	Etiwanda 4	Redondo Beach 5	Redondo Beach 6
6/1/2000	OFF	OFF	OFF	OFF	OFF	OFF	(25,421)	10,597	OFF	OFF	OFF	OFF	OFF	OFF
6/2/2000	OFF	OFF	OFF	OFF	OFF	OFF	(28,702)	2,825	OFF	OFF	OFF	OFF	OFF	OFF
6/3/2000	OFF	OFF	OFF	OFF	OFF	OFF	(28,647)	716	OFF	OFF	OFF	OFF	OFF	OFF
6/4/2000	OFF	OFF	OFF	OFF	OFF	OFF	(34,241)	(4,892)	OFF	OFF	OFF	OFF	OFF	OFF
6/5/2000	OFF	OFF	OFF	OFF	OFF	OFF	(25,577)	12,331	OFF	OFF	OFF	OFF	OFF	OFF
6/6/2000	OFF	OFF	(50,189)	(40,774)	OFF	OFF	(11,398)	21,132	OFF	OFF	(41,821)	(38,696)	OFF	OFF
6/7/2000	OFF	OFF	(52,238)	(40,662)	OFF	OFF	(6,477)	25,255	OFF	OFF	(43,313)	(38,406)	OFF	OFF
6/8/2000	OFF	OFF	(46,051)	(37,433)	OFF	OFF	(4,250)	26,166	OFF	OFF	(40,427)	(39,084)	OFF	OFF
6/9/2000	OFF	OFF	(37,491)	(29,698)	(27,681)	OFF	442	30,828	OFF	OFF	(34,639)	(32,870)	(36,533)	OFF
6/10/2000	OFF	OFF	OFF	OFF	OFF	OFF	(17,458)	10,963	OFF	OFF	OFF	OFF	OFF	OFF
6/11/2000	OFF	OFF	OFF	OFF	OFF	OFF	(34,148)	(6,147)	OFF	OFF	OFF	OFF	OFF	OFF
6/12/2000	OFF	OFF	(50,657)	(41,239)	OFF	OFF	(15,913)	17,302	OFF	OFF	(42,286)	(38,057)	OFF	OFF
6/13/2000	147,190	162,875	333,395	336,956	166,973	146,897	386,538	417,230	116,207	118,522	332,825	330,524	156,301	155,381
6/14/2000	572,001	600,197	1,140,579	1,138,355	602,535	553,351	1,234,139	1,257,426	449,712	451,050	1,135,559	1,132,328	591,084	590,836
6/15/2000	194,908	212,191	413,557	417,777	214,373	191,368	473,290	500,122	154,264	155,852	415,776	415,936	204,221	203,625
6/16/2000	OFF	OFF	(40,701)	(32,502)	OFF	OFF	(1,865)	36,263	OFF	OFF	(35,655)	(33,886)	OFF	OFF
6/17/2000	OFF	OFF	OFF	OFF	OFF	OFF	(34,195)	(1,743)	OFF	OFF	OFF	OFF	OFF	OFF
6/18/2000	OFF	OFF	OFF	OFF	OFF	OFF	(34,618)	(8,281)	OFF	OFF	OFF	OFF	OFF	OFF
6/19/2000	OFF	(28,832)	(44,309)	(35,316)	(27,050)	(31,934)	(13,256)	13,908	OFF	OFF	(38,151)	(33,921)	(36,990)	(37,602)
6/20/2000	OFF	(26,835)	(32,338)	(24,191)	(23,250)	(30,992)	10,833	44,380	OFF	OFF	(27,344)	(24,471)	(34,539)	(36,659)
6/21/2000	52,496	65,347	145,133	151,021	68,125	55,997	190,560	220,267	42,444	45,358	147,391	148,229	58,233	57,409
6/22/2000	(32,338)	(23,374)	(25,093)	(17,376)	(21,995)	(26,759)	10,039	44,124	(24,803)	(22,128)	(19,059)	(19,924)	(31,107)	(31,812)
6/23/2000	OFF	OFF	(53,904)	(40,553)	OFF	OFF	(10,291)	23,550	OFF	OFF	OFF	OFF	OFF	OFF
6/24/2000	OFF	OFF	OFF	OFF	OFF	OFF	(34,322)	4,036	OFF	OFF	OFF	OFF	OFF	OFF
6/25/2000	OFF	OFF	OFF	OFF	OFF	OFF	(33,852)	2,111	OFF	OFF	OFF	OFF	OFF	OFF
6/26/2000	504,195	531,663	1,012,408	1,011,366	533,507	489,390	1,098,062	1,123,499	397,503	399,067	1,008,729	1,006,176	521,747	521,661
6/27/2000	641,207	672,795	1,269,971	1,267,329	674,476	619,685	1,370,755	1,394,021	504,555	505,316	1,264,692	1,262,139	663,025	662,941
6/28/2000	586,457	615,252	1,165,362	1,163,370	617,655	567,136	1,262,080	1,293,478	461,752	462,516	1,160,733	1,157,076	606,463	605,050
6/29/2000	472,318	498,562	946,149	947,668	499,617	457,571	1,035,204	1,064,119	372,418	373,211	941,797	940,601	488,946	488,785
6/30/2000	(36,339)	(25,335)	(29,638)	(21,508)	(23,205)	(30,589)	12,331	42,440	(26,660)	(25,000)	(23,032)	(20,837)	(32,577)	(34,800)

"OFF" means the unit would not have been dispatched in any hour based on its full load dispatch price and the simulated price.

Profit calculations, by hour, summed over the day:

If Simulated Price >= Dispatch Price then Full Load Revenues minus Full Load Costs (average heat rate).

If Simulated Price < Dispatch Price then Min Block Revenues minues Min Block Costs (average heat rate).

prices, so 3,123 MW were dispatched uneconomically. Of course at the real prices, the operation of some of these units would have been profitable, but that does not contradict the argument that the simulated prices underestimate competitive prices during some of the high-priced hours. Conversely, units are also dispatched off in the simulation during individual low-priced hours in a manner that would not be feasible in actual operation as the plants would need to be kept on at minimum load, increasing supply at a given hourly price. The two effects need not cancel out. A simulation that accounts for start-up and minimum load costs and other operating inflexibilities would address this understatement, but this would be a more complicated analytical effort that would require a much more elaborate scheduling and dispatch methodology.[54]

Similarly, ten of these units were dispatched in the base case simulation during one or more days over the period June 16-June 20, accounting for a total output of 24,945 MW over this period, or 4,989 MWh/day. It can be seen in Table 8 that only the output of El Segundo 3 on June 20 would have been profitable at the simulated prices, so the uneconomic dispatch was 4,311 MWh/day.[55]

Finally, all 13 units were dispatched over the period June 22-June 25 for a total of 16,629 MW, or 4,157 MW/day, almost all of which was dispatched on June 22, and only El Segundo 3 would have been profitable on any of these days if the unit were required to remain on line at minimum load during the other hours. The uneconomic dispatch therefore was 3,464 MWh/day, and was concentrated on June 22.[56]

It is also informative to compare the pattern of daily average prices between the real-world and the base-case simulation as portrayed in Figure 9. It can be seen that the simulated price generally moves with the real-time price but has materially lower peaks over the days June 13-15, June 21, and June 26-29.

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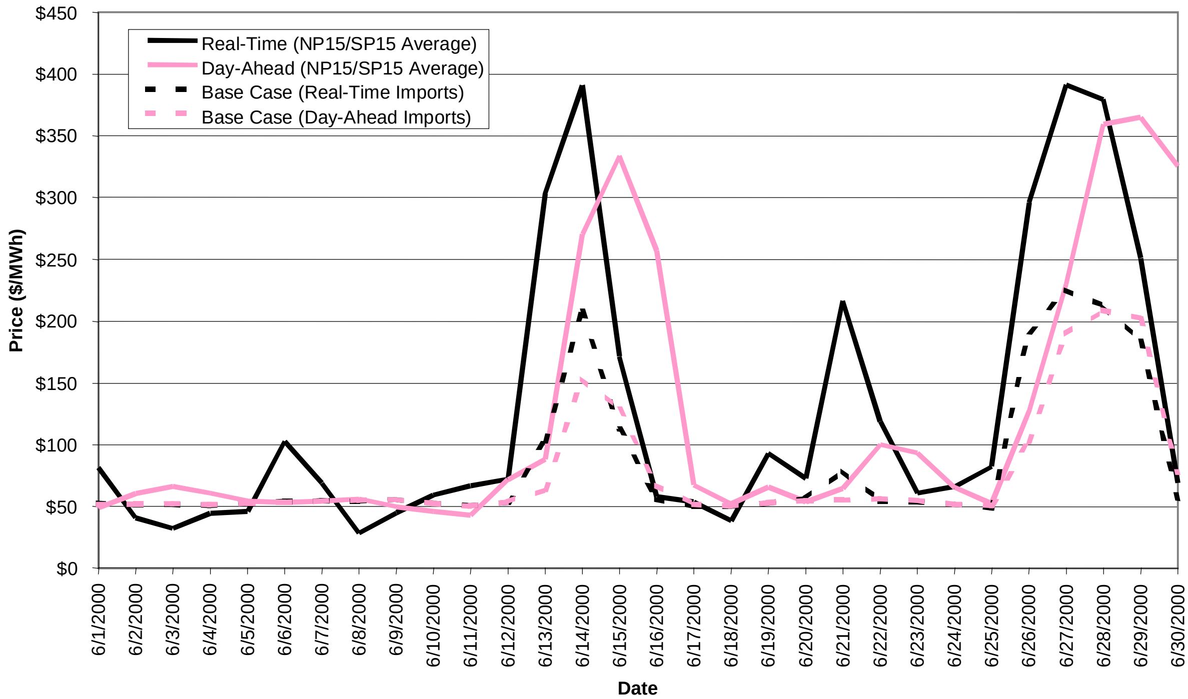
54 These calculations do not take account of possible ancillary service revenues, which are not included in the simulation. If it is assumed that capacity not dispatched to provide energy would be available to provide reserves up to the ramp limit, and would be priced at the average of the day-ahead spinning and non-spinning reserve prices, then Alamitos 4 and El Segundo 3 would have been profitable to operate on June 12 (Table 25, at end of document). The uneconomic output over June 1-12 in the simulation would then have been 34,420 MWh or 2,868 MWh/day.

55 As above, these calculations do not take account of possible ancillary service revenues, which are not included in the simulation. If it is assumed that capacity not dispatched to provide energy would be available to provide reserves up to the ramp limit, and would be priced at the average of the day-ahead spinning and non-spinning reserve prices, then the units dispatched to operate on June 16 in the simulation could have done so profitably (see Table 25). The uneconomic output over June 17-20 in the simulation would then have been 13,176 MWh or 3,294 MWh/day.

56 Once again, these calculations do not take account of possible ancillary service revenues, which are not included in the simulation. If it is assumed that capacity not dispatched to provide energy would be available to provide reserves up to the ramp limit, and would be priced at the average of the day-ahead spinning and non-spinning reserve prices, then many of the units dispatched to operate on June 22 in the simulation could have done so profitably, and it might have been economic for some of the remaining plants to remain on line to earn ancillary service revenues on June 23 (i.e., Alamitos 3 and 4). The remaining uneconomic output on Etiwanda 2 and 3 on June 22 would have been 1,997 MWh (see Table 25).

Figure 9
Comparison of Daily Average Prices



Note: Base Case simulation prices were capped at $750/MWh and a Nox price of $10/lb was used.

D. Sensitivity Analysis

Without going to a full dynamic multi-price simulation methodology to account for the many relevant features of an electricity system, we can use sensitivity tests of the static single-price simulation methodology to gain some insight about the likely magnitude of the effects of the simulation simplifications. The tests address the simplifying assumptions and some of their interactions in determining the market-clearing price.

There are several potentially important assumptions embodied in the replicated simulation results. While we lack the data required to assess the impact of some of these assumptions, an important purpose of this paper is to assess the practical significance of those simplifying assumptions that we are able to vary. A complicating factor in providing this sensitivity analysis is that it is anticipated that the effects of variations in assumptions will not necessarily be linear, hence we cannot simply compute a few cases and sum the effects to assess their cumulative impact. We have attempted to balance computational complexity with informational needs by calculating prices for all of the permutations and combinations of certain assumptions (hydro capacity, reserve requirements, environmental limits (e.g., delta dispatch), NUG outages and regulated unit output, and undertaken a much more limited set of price calculations for some of the other sensitivity assumptions. As noted above, all of the sensitivity analyses are based on an import supply curve calibrated against real-time prices.

Reserves

The first of the sensitivity analyses we have undertaken concerns the level and method of accounting for reserves in the Joskow-Kahn simulations. Although the original Joskow-Kahn simulations assumed an overall CAISO ancillary services requirement of 10 percent of load for reserves and upward regulation and dispatched generation based on its offer prices to meet load plus 10 percent,[57] the later simulations have assumed an overall CAISO ancillary services requirement of only 3 percent (for upward regulation) and dispatched generation to meet load plus 3 percent.[58] As we have pointed out in previous papers,[59] a 3 percent ancillary services requirement is too low and not consistent with the real-world operation of the transmission system, as the CAISO would almost certainly shed load before it would let its operating reserves go to zero. On the other hand, dispatching generation to meet load plus 10 percent based on energy offer prices is likely to overstate energy prices during non-shortage conditions as it in effect requires the CAISO to buy energy to meet its reserve requirements.[60]

Thus, while the assumption of a 3 percent ancillary services requirement is inappropriate, it is not possible to precisely replicate the impact of the CAISO's actual ancillary services requirements in idealized generation stacking models of the kind utilized by Joskow and Kahn, (or BB&W, Mansur or Borenstein and Saravia). Furthermore, reserve data at the detail needed for the simulation model are not available from the ISO. We have therefore examined the impact on the simulated price of several alternative rough representations of CAISO ancillary services requirements, none of which provides a fully accurate portrayal of actual ancillary service requirements but which are intended to roughly bound the appropriate price impacts. These alternatives are:

- R2: Energy is dispatched to meet CAISO real-time load increased by 10 percent to reflect ancillary service requirements.

- R3: Energy is dispatched to meet CAISO real-time load increased by 3 percent to reflect impact of ramping constraints on the cost of energy dispatched to meet load,[61] plus available capacity requirement of load plus 10 percent.

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57 Joskow-Kahn March 2001, p. 11. The 10 percent margin has also been assumed in some other analyses, such as Hildebrandt.

58 Joskow-Kahn July 2001, pp. 7-8, and Joskow-Kahn February 2002, p. 13.

59 Harvey-Hogan October 2000, pp.20-25, and Harvey Hogan December 2001, pp. 36-40

60 We made similar observations in Harvey-Hogan April 2001, pp. 15-17.

61 This 3 percent adjustment is consistent with the Joskow-Kahn methodology and provides a very rough adjustment for the extent to which ramping requirements on regulating units or on operating reserves in non-shortage situations require that energy demand be met with energy from units that are out of merit. That is, energy demand is met from internal units with offer prices that are higher than the offer prices of other units that are providing reserves and are not dispatched to meet energy. This adjustment does not account for the extent to which short-term variations in load must be met with higher offer-price quick-ramping units due to an inability of units with lower offer prices to ramp sufficiently quickly to meet the change in load.

- R4: Energy is dispatched to meet CAISO real-time load increased by 3 percent to reflect impact of ramping constraints on the cost of energy dispatched to meet load, plus available capacity requirement (including spinning and non-spinning reserve imports) of load plus 10 percent.

- R5: Energy is dispatched to meet CAISO real-time load increased by 3 percent to reflect impact of ramping constraints on the cost of energy dispatched to meet load, plus an available capacity requirement (including spinning and non-spinning reserve imports plus 500 MW of assumed unloaded hydro capacity) of load plus 10 percent.

The R2 reserve case differs from the base reserve case in that supply is dispatched to meet 110 percent of load, rather than 103 percent. This is consistent with the assumptions used to proxy for CAISO ancillary services requirements in a variety of contexts, including the original Joskow-Kahn simulation, and probably roughly corresponds to the CAISO's actual demand for capacity. Significantly, this measure of demand correctly attributes high prices to true shortage under shortage conditions. On the other hand, as noted above this measure is likely to overstate energy prices during non-shortage conditions as it in effect requires the CAISO to buy energy to meet its reserve requirements. The impact of changing the ancillary service assumption to that utilized in the original Joskow-Kahn simulation, while holding the remainder of the methodology constant, is to raise the simulated price without a $750 price cap to $165.69 (well above the actual price). If a $750 price cap is applied to the hourly prices, the simulated price is $115.74 (slightly lower than the actual average hourly price but higher than the average lowest INC price).

The R3 reserve case attempts to correct for the potential of case R2 to overstate market prices in non-shortage situations by dispatching energy to meet 103 percent of load as in the base case. The 3 percent margin is taken to roughly reflect the impact of ramping constraints on the cost of the generation required to meet load. In addition the level of total capacity available at this price is calculated, and if the capacity is less than 110 percent of load, the price of energy is raised until sufficient imports are drawn into the market to provide capacity equal to 110 percent of load. In this calculation, capacity is defined as total must take energy plus all available dispatchable capacity, plus import supply at the market clearing price.

This measure identifies hours of capacity shortage without overstating the energy cost of meeting load. We do not have an empirical basis for verifying whether the 3 percent assumption accurately reflects the impact of real-world ramping constraints. In addition, the measure of available capacity is very approximate and may understate the available capacity. Replacing the 10 percent ancillary service requirement with a 3 percent margin in the dispatch, but acquiring imports to maintain an adequate reserve margin results in a simulated uncapped price of $161.41/MWh. If a $750/MWh price cap is applied to the hourly prices, the average simulated price is $111.46/MWh, again relatively close to actual market prices.

The R4 reserve case attempts to better represent available capacity by including in the measure of available capacity (but not in the energy dispatch) the hour ahead schedules for spinning and non-spinning reserve imports. The R4 case further increases the available capacity and the simulated uncapped price falls to $150.25. If a $750/MWh price cap is applied to the hourly prices, the average simulated price is $106.22, with the average capped price slightly less than real-world price levels.

The R4 reserve case might still understate available capacity to the extent that generation treated as non-dispatchable in the Joskow-Kahn simulation methodology but which is actually dispatchable in the real-world, was providing reserves or regulation. In particular, we have in mind the potential for hydro-generating capacity to have been available in excess of the energy generated from the hydro units. We have no empirical basis for determining this number, but have included in the available capacity in Case R5 a further allowance for 500 MW of unloaded capacity on hydro units (in addition to imported reserves) to provide a sense of the impact of such capacity. The simulated uncapped price falls to $138.77 in the R5 case, while the simulated price with a $750 hourly price cap is $100.94. The capped price is noticeably less than actual prices, but much closer to actual prices than to the prices simulated by Joskow and Kahn.

Hydro Energy

The second sensitivity case we considered is the level of hydro energy available on peak. Joskow-Kahn assumed in their later papers that 8,500 MW of hydro was available in the high-load hours and assumed that 8,000 MW were available in their original paper. We do not know the actual level of hydro energy that was available during the on-peak hours in June 2000, but have included sensitivity cases for a variety of possible levels to permit assessment of the impact of this assumption. The cases evaluated were:

- H1: 8,500 MW maximum
- H2: 8,000 MW maximum
- H3: 7,500 MW maximum
- H4 7,000 MW maximum
- H5: 7,000 MW at $0, 7001-7500 MW at $500
- H6: 9,000 MW maximum

Tables 10 and 11 summarize the impact of varying the assumptions regarding the amount of hydro energy available on-peak for the base reserve case and cases R2 and R5. The average uncapped prices reported in Table 10 are generally far above actual price levels.

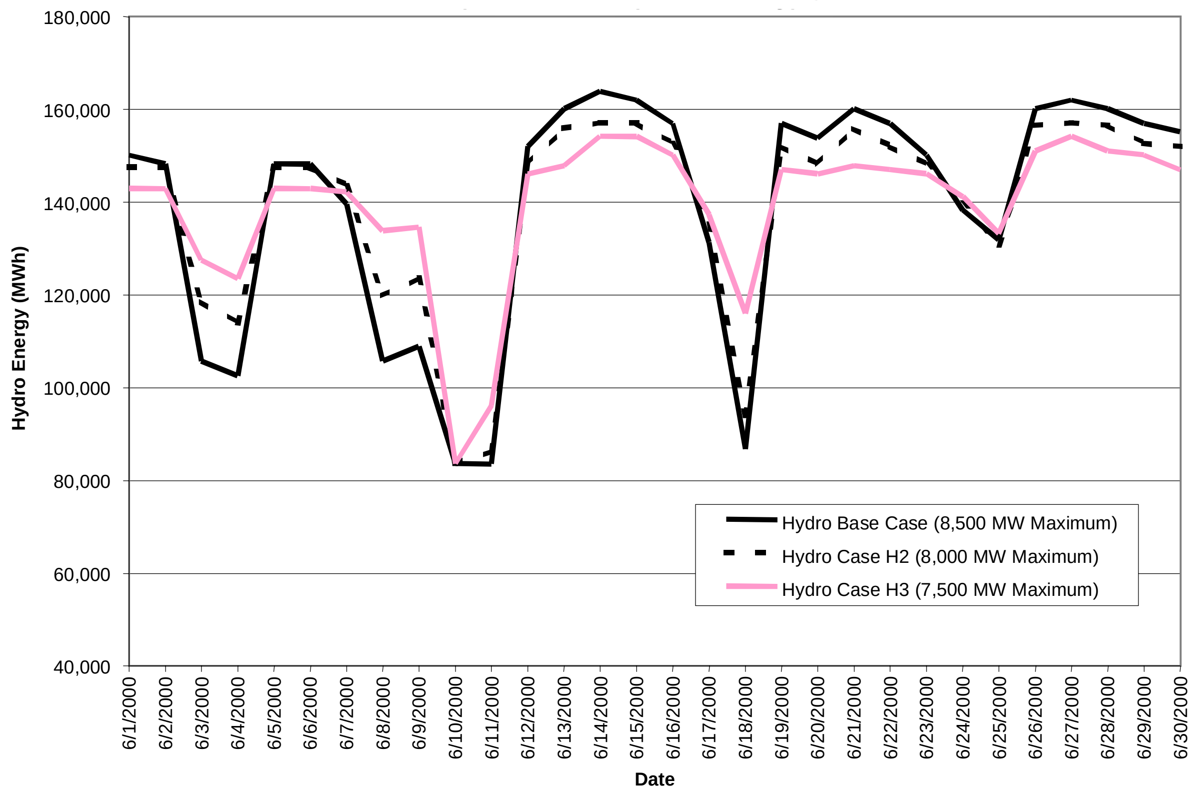
Table 10 HYDRO AND RESERVE CASES UNCAPPED PRICES			
	R1	**R2**	**R5**
H6	82.36	154.63	127.06
H1	91.97	165.69	138.77
H2	103.50	178.35	150.29
H3	115.27	193.01	162.22
H4	125.93	206.99	178.04
H5	118.71	197.16	162.32

The average simulated prices calculated with a $750 hourly price cap tend to approximate actual prices. In these simulations a 500 MW difference in the amount of hydro energy available in the peak hours tends to reduce prices by about $5/MWh.

Table 11 HYDRO AND RESERVE CASES CAPPED PRICES			
	R1	**R2**	**R5**
H6 (9,000 MW)	77.74	111.04	96.17
H1 (8,500 MW)	82.63	115.74	100.94
H2 (8,000 MW)	86.95	120.87	106.26
H3 (7,500 MW)	91.54	126.03	111.15
H4 (7,000 MW)	96.81	131.63	117.41
H5 (7,000 MW + 500 MW)	94.99	130.18	111.25

These simulation results for the alternative hydro cases can be used to illustrate some of the impacts of the assumptions used in the Joskow-Kahn study to determine the availability of hydro power. The allocation of a disproportionate amount of hydro power to the highest load hours during the month, not only allocates hydro power across hours within the day, but also across days. Thus, it can be seen in Figure 12, that the total amount of hydro power available by day varies a great deal from day to day in the base case, with very low levels of hydro power available on some days. As the amount of hydro power assumed to be available in the peak hours is reduced, more hydro power is available on some of the off-peak, particularly weekend, days. It is not clear whether the hydro resources actually had the ability to shift this much energy not only from hour to hour but day to day. It will be seen in the discussion of the sensitivity cases that the very small amount of hydro capacity available on some days under the base case hydro assumptions, in conjunction with the assumed very low supply elasticity of imports, results in weekend price spikes in some of the sensitivity cases that did not occur in the actual world.

Figure 12
Daily Modeled Hydro Energy



Environmental

The third sensitivity factor was for environmental restrictions. These are very difficult to account for because many of these restrictions are not public and we are not sufficiently familiar with their impact to account for their effects. Moreover, those restrictions with which we are familiar (Mirant's Delta Dispatch restriction) had variable impacts that are difficult to model. The delta dispatch restrictions applied to eight of the Mirant generating units in the Bay Area during the period roughly from late May to Mid-July. These restrictions were intended to prevent the discharge of waste water from overheating the river and interfering with fish spawning during this period. During this period, the eight units were not permitted to operate at a level that would result in outlet water temperatures in excess of 86 degrees, except at the specific direction of the CAISO either to maintain local reliability or in emergency conditions. These restrictions resulted in large amounts of capacity being unavailable for dispatch, except during emergency conditions.

The base case E1 is the Joskow-Kahn simulation which does not take account of any environmental restrictions. Case E2 proxies roughly for the impact of the Delta Dispatch restrictions on the Mirant Contra Costa and Pittsburgh units by reducing the capacity of the units subject to Delta Dispatch (Contra Costa 6-7, Pittsburgh 1-6) by 50 percent. This capacity figure is likely too high on most days but may be too low at times. Given the variability of river conditions and tides, it is not apparent that there is any simple rule that would capture the reality of these limits. Case E2 potentially understates capacity on high load days because it does not account for the possibility that the Mirant capacity could sometimes be dispatched in non-emergency (i.e., non-shortage conditions) as a result of intra-zonal congestion (i.e., reliability must-run (RMR) dispatch).

Case E3 attempts to account for the impact of both Delta Dispatch restrictions and RMR dispatch on the Mirant units by setting the output of the Mirant units equal to their actual CEMS output in that hour.[62] The Mirant units are therefore effectively treated as price takers whose output was controlled by the CAISO's RMR desk, which may be an accurate characterization.

Table 13 summarizes the impact of varying the assumptions regarding the impact of environmental restrictions across several reserve cases. To keep the discussion manageable, we have reported results only for the base case hydro assumption and capped prices.[63] It can be seen that the environmental assumptions have a material impact on the simulated capped prices, raising them by an average of $9 to $14/MWh even though we are only taking account of the restrictions imposed on a single company (Mirant). This sensitivity case suggests the importance of accounting for environmental restrictions in price simulations.

Table 13

ENVIRONMENTAL AND RESERVE CASES
CAPPED PRICES

	R1	R2	R5
E1	82.63	115.74	100.94
E2	90.48	129.33	111.00
E3	85.92	129.42	109.14

All simulations reported use base case hydro assumptions.

Regulated Unit Output

Given that the purpose of the simulation model is to separate the effects of the exercise of market power by generators, the role of generation owned by regulated utilities deserves special attention. As regulated entities and net buyers of electricity, the utilities would have an interest in lower, not higher prices. If anything, these generators would have an incentive to exercise their market power by producing too much, not too little output. It follows, therefore, that the actual output of the utilities is an upper bound on their likely production at the observed prices in

62 The raw hourly CEMS output is scaled down to reflect plant energy use using the June 2000 ratio of total net output reported to the EIA and total gross output reported in the CEMS data.

63 The average simulated uncapped prices for Case E3 and R2 or R5 consistently exceeded $200/MWh.

a competitive market. Any simulated output in excess of the actual production for these suppliers would be evidence questioning the simulation model rather than evidence of an exercise of market power by the regulated suppliers.

Since the Joskow-Kahn simulation uses the theoretical capacity and estimated costs of utility generation to determine their output, actual prices could exceed the simulated prices because of the outages and bids of the utility generation rather than due to the exercise of market power by the non-utility generators. We attempt to assess the extent to which the Joskow-Kahn simulation model may overstate the supply available from utility generation by capping the output of the utility steam generation in the model based on the hourly CEMS data. The output of gas turbines (GT) is not capped but their capacity is derated as in the base case per NERC EFOR ratings. This is case RUO2/N1.[64] The simulated prices are reported in Table 14 for several alternative sets of reserve and environmental assumptions. It can be seen that the difference between the predicted and actual output of the regulated units accounts for a $3-$7 increase in simulated prices across these cases.

Table 14
REGULATED UNIT NUG OUTPUT CASES
CAPPED PRICES

	R1		R2		R5	
Case	**E1**	**E3**	**E1**	**E3**	**E1**	**E3**
Base	82.63	85.92	115.74	129.42	100.94	109.14
RUO2/N1	85.90	89.89	122.31	137.07	105.16	115.32
RUO2/N2	93.08	99.68	142.21	157.58	120.40	129.43
RUO2/N3	98.09	107.53	148.71	167.12	125.08	135.24

All simulations reported use base case hydro assumptions.

<u>NUG Outages</u>

A further category of sensitivity analysis concerns the availability of non-utility generation. Joskow-Kahn model the impact of outages by proportionately derating all units. The methodology employed in the Joskow-Kahn simulation model tends to understate prices by overstating the available capacity. There are four reasons for this. First, in the actual operating world outages are often lumpy, so the impact of outages on the available capacity is less smooth than in the Joskow-Kahn simulation. The assumption that outages are proportionate therefore tends to increase the available capacity in shortage hours, and indeed less capacity would be needed and prices lower for any given level of capacity in such a world.

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[64] Since no CEMS data are available for Hunters Point Units 2 and 3, their output is not capped, but their capacity is derated as in the base case.

Second, this methodology cannot distinguish between the possibility that actual prices are higher than simulated prices because actual outages and deratings exceeded those that would be predicted by the NERC data and the possibility that suppliers raised prices by exercising market power. Third, their model does not take account of start-up and minimum load costs, so it is possible to meet incremental load during individual simulation hours with the output of steam units that would not be economic to start-up or keep on line over night in the actual world. We showed above that many units were dispatched to meet load in the base case that could not profitably operate if start-up and minimum-load costs are accounted for.

Fourth, their simulation model (and most production costing models) also assumes perfect foresight in a non-chronological model, i.e., their simulation assumes that steam units can be instantly started to meet load, and that demand is never misforecasted. Thus steam units are never off-line during high load conditions nor on-line during low load conditions. This is case N1.

In practice, however, there was a substantial element of unpredictability to real-time prices during June 2000. The difference between day-ahead PX prices in NP-15 and the real-time imbalance price had a mean absolute value of $148, and a standard error of $236, while the figures were an absolute value of $136 in SP-15 and a standard error of $221. Modeling a world that had this degree of uncertainty as one in which suppliers had perfect foresight in scheduling their units on- and off-line is a non-trivial assumption. Moreover, this variation between day-ahead and real-time prices was not simply hour-to-hour variations that cancelled out over the day. The difference between the average on-peak (16-hour block) weekday NP-15 day-ahead PX and real-time ISO price differed by $20/MWh on 19 of the 22 week days during June 2000. The similar statistic for SP-15 was 18 out of 22 weekdays.

On balance, these assumptions in the Joskow-Kahn simulation tend to depress the level of simulated prices relative to actual prices absent the exercise of market power. We have analyzed two alternative cases to provide an assessment of the potential impact on the simulated price of these simplifications. One alternative approach is to use the actual on-line off-line status of non-utility steam units, per the CEMS database, to determine their availability. Thus, only units that were on-line in each hour in the actual world can be dispatched to meet load in this case. This is case N2. This case, therefore, controls for the operating status of these generators, and prices will be higher in the simulation to the extent that steam units were off-line in the real-world due to outages, start-up costs, or misforecasted demand. This case cannot distinguish between generators that were off-line because of outages, higher than anticipated load, problems coming on line, or as a result of physical withholding. If steam units were in reality off-line as a result of physical withholding, this sensitivity case overstates the competitive price level. Conversely, however, if these units were off-line in reality because of outages or unpredictable demand, then the Joskow-Kahn simulation methodology understates the competitive price level. GTs are assumed to be available in this simulation in every hour regardless of their on/off status in the real world.

Case N2 accounts for forced unit outages but makes no allowance for unit deratings. It therefore still has the potential to overstate the capacity actually available to the CAISO. Case N3 attempts to account for this possibility by excluding off-line units and derating on-line units to reflect NERC derating data. Thus, steam units are on line if they were on line in real-time and are derated based on (EFOR-FOR)/(1-FOR) while, as in Cases N1 and N2, GTs are assumed to be available regardless of their on/off status per the EFOR rating.

Table 14 also reports the results of the N2 and N3 cases, both in conjunction with the RUO2 case for regulated unit output. It can be seen that taking account of the actual on off status of the NUG units has a material impact on simulated prices under either of the environmental assumptions and all of the cases which take account of actual CAISO reserve requirements. The simulated prices in these cases are generally consistent with actual prices, but noticeably higher than the actual price level in the 10 percent ancillary service requirement case (R2). It appears to us that this sensitivity case has a rather material impact on the simulated price level, suggesting that it is important that simulations take account of these considerations. As we noted above, the high prices simulated could reflect the impact of the exercise of market power through physical withholding, but it needs to be shown that such physical withholding actually occurred in order to infer that market power was exercised. Were the units that were off-line outaged? Were the outages legitimate? Were the units off-line because forward prices were in fact inadequate to support operation? Were the units off-line because the demand forecast was wrong and they could not come on-line in time? One cannot conclude that market power was or was not exercised through physical withholding without answering these questions.

None of these cases fully capture the reality of uncertain outages. The approach of proportionately derating all units for their expected outages tends to understate prices as we have pointed out in prior papers. In addition, if real-world outages differ from expected outages (as they might have in 2000 due to hard use), then the simulation would misstate prices. Moreover, the outage data varies in the NERC data only with capacity, making no allowance for age, level of use, cycling versus base-load status, etc.

One interesting feature of these cases is that the 8,500 MW and 9,000 MW on peak hydro cases tend to result in extremely high uncapped prices, as shown in Table 15, that are little different or even higher than the prices simulated assuming lower on-peak hydro. The reason for this is that the assumption that so much water is used to generate energy in the high load hours, reduces the amount of energy available in the mid load level hours. This effect combined with the low actual real-time import levels in these hours[65] and the actual off status of the NUG units produces extreme shortages in some of the mid-load off-peak hours, leading to extreme price spikes. The impact of these shortages on the capped prices is less pronounced, but it can be seen that even the average capped price sometimes increases with the availability of more hydro-energy on peak. These outcomes might be an artifact of the Joskow-Kahn hydro assumptions, either because the quantity assumed to be available on peak is in excess of actual availability, or the assumption that hydro energy is a price taker and simply allocated to certain hours.

[65] In hours with a low level of actual real-time imports, a large price increase is required to meet load.

Table 15 RUO2/N3/E3			
	R1	**R2**	**R5**
Uncapped Prices			
H1 (8,500 MW)	135.76	278.16	206.72
H6 (9,000 MW)	126.78	282.42	210.81
H2 (8,000 MW)	140.72	279.79	220.43
H3 (7,500 MW)	147.22	280.52	216.11
$750 Price Cap			
H1 (8,500 MW)	107.53	167.12	135.24
H6 (9,000 MW)	104.40	171.62	139.19
H2 (8,000 MW)	108.92	166.78	139.53
H3 (7,500 MW)	112.74	167.10	137.11

One of the simplifications of the Joskow-Kahn model is that it does not take account of intra- or inter-zonal congestion. While there was generally not a great deal of inter-zonal congestion during June 2000, it was not entirely absent and could affect comparisons between actual and simulated prices. As a further sensitivity test, we have reported in Table 16 the average simulated prices for the hours in which there was no inter-zonal congestion in the actual world. Comparisons between actual and simulated prices for these hours would control for the direct effects of the failure to model congestion in the simulation, although there would still be potential indirect dynamic effects between congested and uncongested hours. Actual real-time prices were slightly lower in these hours than in all hours, averaging $109.50 with an average lowest INC price of $94.11, which is again in the range of the prices simulated in the R2 and R5 reserve cases.

Table 16 REGULATED UNIT NUG OUTPUT CASES CAPPED PRICES: AVERAGE DURING REAL-WORLD UNCONGESTED HOURS						
	R1		**R2**		**R5**	
Case	**E1**	**E3**	**E1**	**E3**	**E1**	**E3**
Base	74.15	76.96	101.83	114.67	89.69	97.11
RUO2/N1	76.69	80.10	107.01	121.21	92.55	101.86
RUO2/N2	83.07	89.33	125.70	140.50	106.15	114.81
RUO2/N3	87.44	96.54	131.47	149.33	110.19	119.93
All simulations reported use base case hydro assumptions.						

Throughout these sensitivity cases, we have maintained Joskow-Kahn's assumed .33 elasticity for imports. We have observed in prior papers that this elasticity is an important assumption that lacks empirical support.[66] It therefore seems useful to provide some assessment of the impact of alternative assumptions regarding import elasticities. We have therefore repeated the price simulation with an assumed import elasticity of .75. We slightly reduced the magnitude of the simulation effort by restricting this simulation to cases: R1, R2, R5, H1-H6, E1, E3, RUO1, RUO2, N1 and N3.

It can be seen by comparing Table 14 and Table 17 that the impact of assuming a higher import elasticity is generally to raise the average simulated price, but for some of the more high priced cases, the higher assumed import elasticity lowers the average simulated price. These mixed price impacts reflect the two countervailing effects of changes in import elasticities. On the one hand, a higher import elasticity means that an increase in internal California supply in the simulation relative to the real-world produces less of a decline in the market clearing price, while conversely reduced internal California supply relative to the actual world requires smaller price increases in order to attract sufficient imports to close the gap.

Table 17
.75 IMPORT ELASTICITY
CAPPED PRICES

	R1		**R2**		**R5**	
Case	**E1**	**E3**	**E1**	**E3**	**E1**	**E3**
H1						
RUO1/N1	91.78	95.28	116.61	127.34	105.74	111.52
RUO2/N3	105.04	111.40	137.53	150.41	123.09	128.63
H2						
RUO1/N1	95.57	99.23	120.59	129.03	109.54	114.14
RUO2/N3	106.64	112.93	140.53	148.39	123.87	131.39
H3						
RUO1/N1	99.38	103.28	123.79	129.49	113.06	117.81
RUO2/N3	110.35	114.61	136.86	146.67	123.27	128.55

As a further sensitivity test, the price simulation was repeated with an assumed import elasticity of 1.5. The change in assumed elasticity again had a mixed effect, tending to raise the average price if it was less than \$120 and lower it if the average price exceeded \$120 (see Table 18). This result reflects the fact that the more elastic the import supply curve, the less impact variations in

66 While the elasticity estimate assumed by Joskow and Kahn is loosely tied to results reported in BB&W, (Joskow-Kahn March 2001, p. 12, Joskow-Kahn February 2002, p. 15) the BB&W methodology for estimating import supply curves is itself (see Harvey-Hogan October 2000, pp. 35-36) poorly described and of uncertain validity.

other supplies or assumed loads have on the market clearing price. Nevertheless, it is noteworthy that the base case simulated price ranges from $82.63 at an elasticity of .33, to $91.78 at an elasticity of .75, to $99.22 at an elasticity of 1.5, so it is important in simulating prices to either base the analysis upon reliable estimates of this parameter or to allow for a range of values in sensitivity cases.

Table 18
1.5 IMPORT ELASTICITY
CAPPED PRICES

	R1		**R2**		**R5**	
Case	**E1**	**E3**	**E1**	**E3**	**E1**	**E3**
H1						
RUO1/N1	99.22	102.79	118.00	126.26	109.92	114.51
RUO2/N3	110.25	115.16	131.92	142.19	121.85	125.81
H2						
RUO1/N1	102.30	105.90	120.88	127.29	112.41	115.97
RUO2/N3	110.10	116.07	133.67	139.13	122.56	127.52
H3						
RUO1/N1	105.31	108.96	122.95	127.12	114.65	118.33
RUO2/N3	113.62	116.70	131.09	138.11	121.81	125.35

These are only two sensitivity cases, and it might be more realistic to assume higher price elasticities of import supply at low market prices than at high market prices.

The N2 and N3 cases overstate the competitive level of prices to the extent that the simulation does not include the minimum load block outputs of units that are on-line but out of merit. Taking account of minimum load blocks in this manner would be desirable but would require a more complex simulation tool than Joskow and Kahn or we have utilized. As a rough test of the impact of these considerations, the average real-time, and simulated prices have been calculated separately for the peak and on-peak hours. The overstating of market prices in the simulation due to omitting the minimum load block of units on line as a result of start-up and minimum load costs or operating inflexibilities should be concentrated in the off-peak hours. These results are portrayed in Table 19.

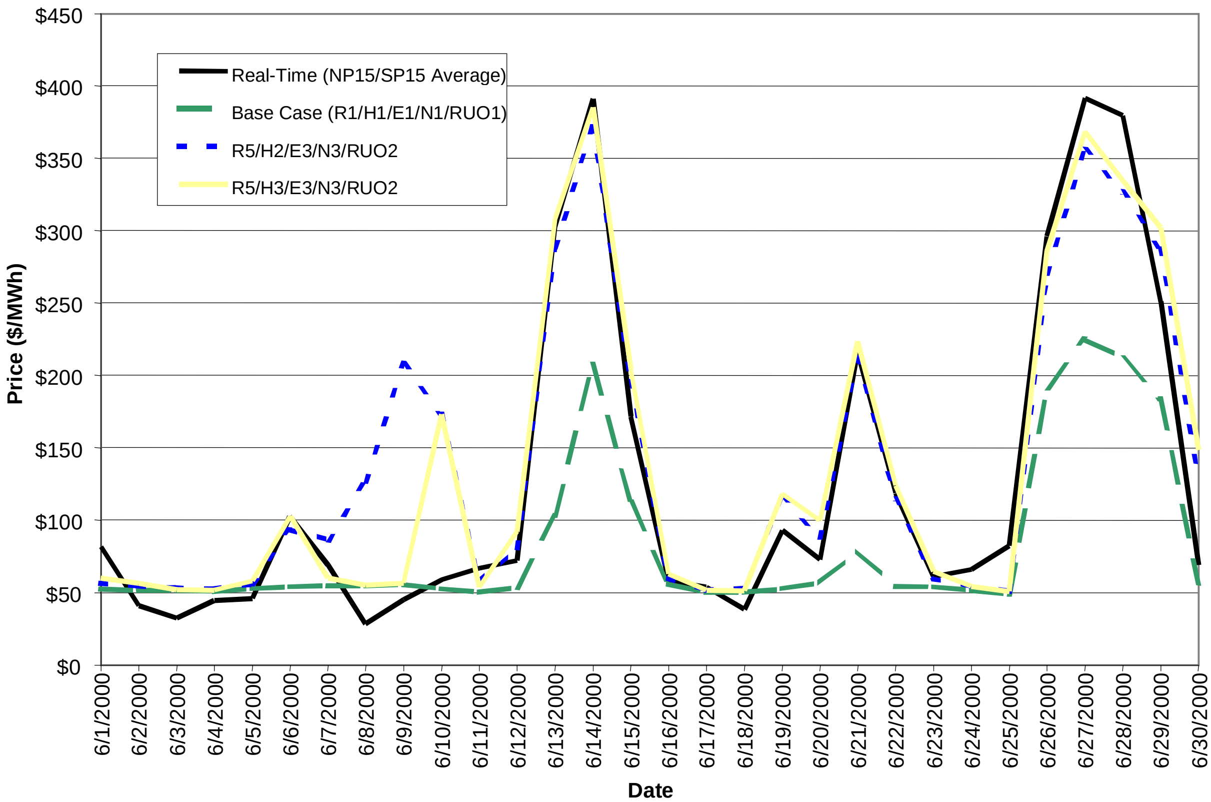
Table 19 PEAK OFF-PEAK SENSITIVITY CAPPED PRICES				
	SP-15	**NP-15**	**Base Case**	**RU02/N3/ E3/R5/H1**
Average	121.95	131.55	82.63	135.24
On-Peak Average	191.59	201.40	117.02	213.42
Off-Peak Average	55.33	64.73	49.73	60.45

It is seen that the simulated on-peak prices for the RUO2/N3/E3/R5/H1 case are also consistent with actual on-peak prices, as are the off-peak prices. The lack of impact of RMR and minimum load schedules in the off-peak hours may be attributable to the fact that load is generally in the relatively flat portion of the supply curve in these hours so that forcing a little additional supply into the supply curve had little impact on the actual market-clearing price.

Figure 20 portrays the average daily actual real-time price, the base case simulated price and the simulated price using the R5 reserve assumptions, E3 environmental assumptions, RUO2 regulated unit output assumptions, N3 NUG outage assumptions and the H2 and H3 hydro assumptions. It is seen that the simulated prices under the latter assumptions, generally closely parallel actual real-time prices.

Figure 20

Comparison of Daily Average Prices (w/ $750 Price Cap, $10 NOx)



It is noteworthy, however, that the simulated prices are noticeably higher than actual real-time prices during the period June 8-10. In examining the reasons for the high simulated prices on these days, it turns out that these days are middle of the load stack days (i.e., the hours are in the 4th and 5th load deciles), and as the assumed level of on-peak hydro energy is increased, the amount of hydro available during many of the hours on these days falls; recall Figure 12 above. As a result, the simulated prices are higher than actual prices for the H1, H2, H3 and H6 hydro cases (9,000-8,000 MW available on peak) but closely parallel actual prices for the H5 hydro case and closely parallel prices on the 8th and 9th but not the 10th in the H4 hydro case. Real hydro resource management is more complex than the allocation assumed in the Joskow-Kahn model.

It is also informative to analyze the pattern of shortages in the simulation. The simulation based on the R5 reserve case, H2 hydro, E3 environmental, regulated unit output RUO2 and NUG outage case N3 identifies 68 hours of reserve shortage at a price of $750. The simulated shortage exceeded 1,000 MW in 48 of these hours, and exceeded 500 MW in 57 of these hours, suggesting that a lot of additional capacity would have been purchased at the price cap price had it been offered. At least in retrospect, it would not have been profitable to withhold marginal capacity in such a world as it all could have been sold at the price cap price.

This 68 hours of simulated reserves shortage exceeds the actual 35 hours of stage 1 emergency during June 2000, but the calculation of shortage hours in our simulation does not include additional out of market energy that the CAISO may have purchased at prices above $750, reducing the number of shortage hours.

The same cases estimated with an assumed import elasticity of .75 led to 51 hours of shortage, including 40 hours with a shortage of 1,000 MW or more and 48 hours with a shortage of 500 MW or more. Changes in assumptions regarding the level of on-peak hydro power also affect the number of simulated shortage hours.

A complete set of simulation results for an assumed import elasticity of .33 and NOx allowance prices of $10, $20, $30 and $40/lb. is appended as Table 25. It can be seen that the impact of higher NOx allowance prices is much less in our simulation results than in those of Joskow and Kahn. This may reflect their use of SCE rather than Henwood emissions data for some of these units. Somewhat reduced sets of simulation results for assumed import elasticities of .75 and 1.50 and an assumed NOx allowance price of $10/lb. are appended as Tables 26 and 27.

These simulation results suggest that more detailed simulation models, more firmly grounded in actual data would be necessary to distinguish between competitive and shortage explanations for the historical level of electricity prices in California during June 2000 based on the simulation methodology. The apparent sensitivity to assumptions and unknowns reveals a range of error that is both substantial and material. Given these sensitivities, and the many real complications in the electricity system set aside in the simplifications of the model, it is not possible to separate out the effect of the evidence of the exercise of market power and the errors in the model. The margin of error is larger than the effect being estimated.

None of these simulations is a full description of reality and all contain simplifications that may understate or overstate the competitive level of prices. Thus, the range of uncertainty around the level of competitive prices is even greater than indicated by these simulation results. First, the simulations can overstate the competitive level of prices because none of these cases fully take account of the impact of RMR contracts in depressing prices by scheduling RMR units on at minimum load or dispatching units out of merit.[67] Second, the level of reserves available on on-line steam and hydro units may be over or understated and the reserve requirements themselves may be over- or understated from hour to hour. Third, the simulation does not account for the impact of transmission congestion, which could either depress or increase actual prices. Fourth, the simulation may understate the competitive price level because we have not accounted for the impact of environmental restrictions on generators other than Mirant. Fifth, none of the forced outage and derating adjustments are specific to the specific units in the model or take account of the actual level of use during June 2000. Sixth, the CAISO capacities used in some cases overstate or understate unit capabilities and the Henwood heat rate and variable O&M cost data may over- or understate the true values. Seventh, the output of the regulatory must-take and hydro generation is based on monthly averages and various approximations that may misstate average output and certainly misstate hour-to-hour variations in output. Eighth, while some cases (RU02 and N3) account for the impact of start-up costs minimum load costs, and operating

[67] Data on RMR schedules and dispatch instructions is not public to our knowledge. Case E3 accounts for the impact of Delta dispatch restrictions and RMR instructions on the output of the Mirant units, but not on other market participants.

inflexibilities in limiting supply, none fully account for the impact of these factors in keeping units on-line in low-prices power.[68] Ninth, the simulation model presumes that prices are not only determined competitively, but in an efficiently structured market, with perfect communications and perfect dispatch. To the extent that the actual prices are affected by the actual CAISO price determination rules, that the CAISO's dispatch was not perfect, that there were breakdowns in the transfer of data and instructions, actual prices may have been elevated by factors that are unrelated to the exercise of market power. Tenth, none of these simulations models adequately account for the chaos of real-time operations. In the simulations there are no surprises. Table 21 reports the mean, median and variance in load and prices for the 10 load deciles. It is noteworthy that the variation within these deciles tends to be materially lower in the simulated models than in the real-world, aside from the highest deciles, and dramatically lower in the base case simulation. In essence, virtually none of the variation in real-time prices at a given load level is explained by the factors accounted for in the base case simulation. If the difference between the base case simulated price and actual prices is accounted for by the exercise of market power, then there ought to be some explanation of how market power accounts for the enormous variation in actual prices, and thus deviation from simulated prices, at a given load level.

It can be seen that some of the sensitivity cases reported in Table 21 have much higher than actual prices and much higher than actual price variances for the load decile 5. Load decile 5 is the decile in which the available hydro tends to fall as the amount of hydro assumed on peak rises. It can be seen that if the on-peak hydro is assumed to be 7,500 (case H3) rather than 8,000 or 8,500, the increase in hydro available in decile 5 moderates the simulated prices and both they and the variance of prices is greatly reduced.

Overall, however, Table 21 suggests that much of the variation in market forces that is driving real-time prices is not included either in the base case simulation or in the sensitivity cases and that a good portion of the price volatility in some of the sensitivity cases arises from the simplified hydro modeling.

[68] The comparison of on-peak and off-peak prices should account in part for this, but some on-peak hours are low-price hours.

Table 21

Load and Price Data by Decile for June 2000

Decile*	Statistic Type	Modeled Load (103% of Load and Losses)	Real-Time NP15 Price ($/MWh)	Real-Time SP15 Price ($/MWh)	Base Case Price ($750 Cap)	R5H1E3N3RUO2_10 Price ($750 Cap)	R5H2E3N3RUO2_10 Price ($750 Cap)	R5H3E3N3RUO2_10 Price ($750 Cap)
10	Mean	41,904.14	550.82	542.78	345.65	582.97	600.08	613.98
	Median	41,840.79	749.00	735.50	244.83	750.00	750.00	750.00
	Variance**	1,624,489.01	73,597.52	72,627.77	74,756.55	66,593.27	61,922.67	57,062.17
9	Mean	38,162.97	194.74	183.20	66.26	180.72	217.82	253.75
	Median	38,207.80	110.83	110.83	61.56	76.70	100.77	130.53
	Variance**	859,659.16	37,563.58	30,419.76	192.10	37,051.98	48,800.38	54,631.51
8	Mean	35,591.99	120.23	111.15	56.58	73.44	80.70	92.56
	Median	35,623.89	83.78	82.73	55.63	61.48	62.12	63.83
	Variance**	350,109.18	18,905.06	15,920.92	10.67	5,447.07	9,192.43	12,633.47
7	Mean	33,570.36	75.00	71.98	53.42	55.88	57.01	58.96
	Median	33,604.69	73.54	71.77	53.95	55.63	57.31	59.15
	Variance**	384,710.54	3,983.37	4,064.06	15.66	26.19	25.96	51.66
6	Mean	31,552.46	66.90	52.78	53.86	57.34	54.19	55.28
	Median	31,514.67	67.11	56.36	53.98	57.33	54.05	55.16
	Variance**	282,022.67	8,661.17	2,401.55	24.95	40.93	35.91	37.29
5	Mean	29,526.09	54.56	53.26	56.31	159.84	143.31	54.37
	Median	29,380.75	56.02	55.99	54.74	61.56	59.27	53.76
	Variance**	399,955.00	2,369.97	2,236.31	16.04	54,425.46	48,042.32	10.85
4	Mean	27,411.97	76.52	64.53	53.24	95.47	95.47	95.47
	Median	27,481.75	60.87	49.85	53.45	55.16	55.16	55.16
	Variance**	533,002.41	10,986.02	5,562.93	6.33	20,561.54	20,561.54	20,561.54
3	Mean	25,041.32	66.56	57.46	49.38	51.19	51.19	51.19
	Median	24,945.41	64.51	58.77	50.20	52.46	52.46	52.46
	Variance**	438,712.82	2,756.88	1,159.48	22.28	27.54	27.54	27.54
2	Mean	23,193.91	49.16	41.21	46.41	48.20	48.20	48.20
	Median	23,205.64	54.32	45.15	46.38	49.75	49.75	49.75
	Variance**	266,287.47	940.90	867.26	36.27	44.00	44.00	44.00
1	Mean	21,366.53	60.99	41.12	45.21	47.33	47.33	47.33
	Median	21,454.40	63.67	48.21	45.52	49.27	49.27	49.27
	Variance**	432,665.60	578.88	686.69	21.68	26.70	26.70	26.70
	Total Mean	30,732.18	131.55	121.95	82.63	135.24	139.53	137.11
	Total Median	30,662.00	71.80	66.72	53.95	57.19	55.63	55.16
	Total Variance**	40,791,861.27	37,310.89	34,992.37	15,249.35	42,809.16	45,168.48	43,341.67

* The definition of load deciles is consistent with Joskow-Kahn (10 = Highest, 1 = Lowest)
** Population variance.

In order to identify the actual exercise of market power, direct evidence of withholding would be a better place to look than the simplified simulation results. Given data that are available to the ISO, but not in the public domain, it should be possible to identify instances of significant and sustained exercises of market power.

III. NEPOOL SIMULATIONS

Although the focus here has been on the California data and simulations, the same methodological difficulties appear in applications in other markets. In the case of a recent study of New England electricity market, there are interesting sensitivity cases that provide further insight into the scope and magnitude of the effects of the modeling simplifications.

Bushnell and Saravia apply a static single-price simulation model to a study of the NEPOOL market. They find that over the period of their study based on estimated marginal costs, simulated outages for thermal units, actual offer prices and availabilities for small thermal generators and nuclear plants, and actual output for hydro units, the resulting simulated "competitive prices" (MC) suggested a markup of 12 percent for the actual NEPOOL prices (ECP for energy clearing price).

However, the detail of the study yields more interesting results than this aggregate summary of the estimated markup above competitive prices. The generalization does not apply to the month-by-month simulation results. The simulated price is much less than the actual market price in a number of the high priced, high peak demand summer months, as can be seen in Table 22. Conversely, the simulated price is often higher than the actual market price in shoulder months with typically slack demand. These latter results violate the assumptions of the simulation methodology.

Table 22 ACTUAL AND SIMULATED PRICES					
	ECP (A)	**MC (B)**	**BIDP (C)**	**ECP/MC Spread (%) (D)**	**BIDP/MC Spread (%) (E)**
June 1999	49.18	30.18	29.12	62.96	-3.64
July 1999	41.14	31.11	29.32	32.24	-6.11
May 2000	72.78	34.12	42.61	113.31	19.92
July 2001	52.24	32.13	31.38	62.59	-2.39
August 2001	43.34	36.56	38.37	18.54	4.72
Average	51.736	32.82	34.16	57.64	3.92

Source: Bushnell and Saravia Table 3, p. 14 and Table 4, p. 15.

ECP = Actual market price.

MC = Simulated price, based on estimated incremental energy costs.

BIDP = Simulated price, based on actual incremental energy bids.

ECP/MC Spread = (Col. A - Col. B)/Col. B.

BIDP/MC Spread = (Col. C - Col. B)/Col. B.

This outcome should not be surprising given that the simulation model does not reflect NEPOOL's actual reserve requirements, as well as omitting generator ramping constraints, transmission congestion, generator minimum run and down time requirements, start-up costs, and minimum load costs. Bushnell and Saravia summarize in their paper many of the simplifications incorporated in the simulation model. For example, the simulation could understate the competitive price because it ignores commitment costs and ramping constraints or overstate the competitive price because it ignores units committed out of merit due to transmission constraints. Thus, the Bushnell and Saravia model should be expected to understate prices in months in which NEPOOL was reserve short and to overstate prices in months during which energy prices were depressed by the amount of capacity that had to be committed at minimum load to meet NEPOOL's reserve constraints, particularly the regional and overall second contingency constraints.

One reading of the extensive list of caveats Bushnell and Saravia provided in their analysis might be that the many simplifications make it all but impossible to draw any conclusions from the comparison of the simulated competitive price and the actual market price obtained in the ECP.[69] However, despite the caveats, the ECP and MC are used for this comparison.

In an effort to provide other tests to identify the exercise of market power, Bushnell and Saravia create three other estimates that complement the ECP and the competitive benchmark based on estimated marginal costs and simulated availabilities (MC). The three alternatives are the

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69 Bushnell and Saravia, p. 7.

simulated price using the actual offer prices for the plants that were available (BIDP),[70] a similar simulation using the actual offer prices and outputs for the modeled thermal generators (THERMALP),[71] and the simulated market clearing price based on the estimated marginal costs of the modeled thermal generating capacity versus the actual output of these thermal generators (MCTHERMAL).[72]

Bushnell and Saravia focus on the comparison of ECP versus MC, BIDP versus MC, and THERMALP versus MCTHERMAL by way of showing different measures of the exercise of market power.[73] They discuss the results with these different indexes and explain some of the discrepancies in terms of the features of the real dispatch that do not appear in the simplified simulation. This use of actual bids in a static single-price simulation is innovative and important. Although the application was designed to illustrate other ways to detect an exercise of market power, the approach could be carried further to help clarify the accuracy of the simulation model in describing the reality of the electric system.

In particular, under the simplifying assumptions of the static single-price simulation model, there would be certain relationships among these indexes. First, the BIDP estimate excludes the plants that are physically withheld, and incorporates the effects of economic withholding in the bids. Hence, in this case all the exercise of market power is contained in the bids and the simulation reduces to replicating the ISO's economic dispatch given the bids. Under the simplifying assumptions of the static single-price simulation, therefore, we should have:

$$ECP=BIDP.$$

Since we have the actual offer prices, this relationship is not statistical, at least if we assume that the dispatch errors are negligible. Hence, the relationship should hold in very hour. Although we do not have the data for every hour, Bushnell and Saravia provide the monthly averages for the 29 months of their study. A simple graph of ECP versus BIDP, as shown in Figure 23, succinctly summarizes the errors implied for the simulation model.

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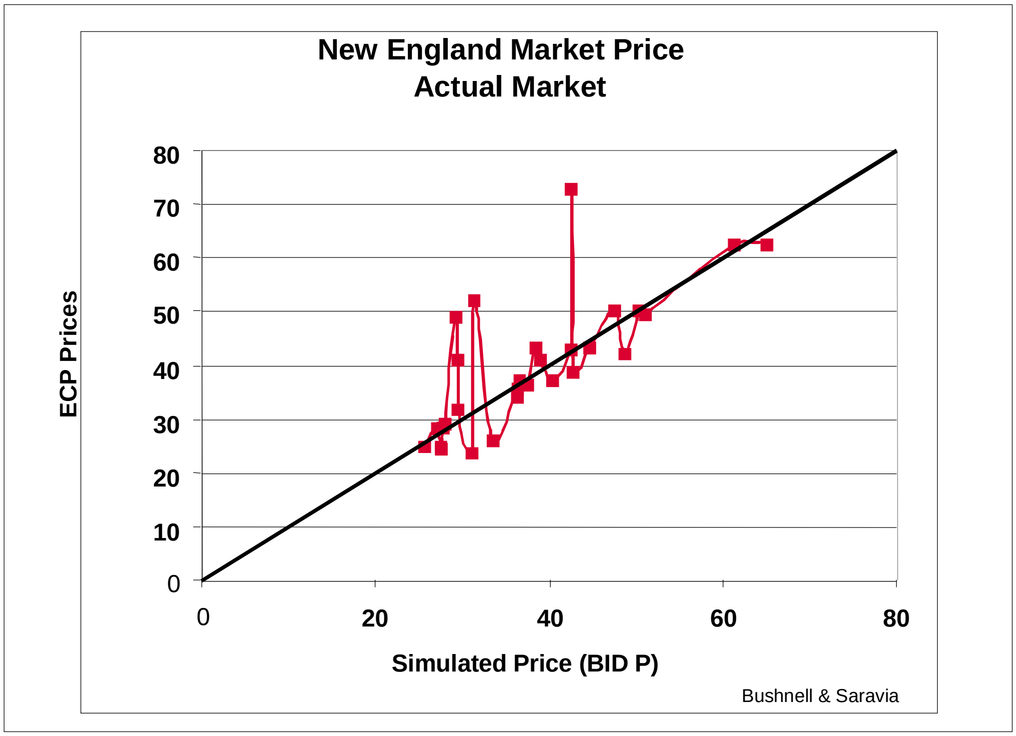
70 BIPD treats small generators, hydro and nuclear units in the same manner as MC. It therefore differs only in that the actual offer prices (and thus actual availabilities) of the thermal generators are used instead of estimated marginal costs and simulated unit availabilities.

71 THERMALP uses the actual offer prices of the thermal units as in BIDP, but instead of dispatching the small generators and nuclear units to meet load, their actual output is taken as given. Thus, the actual offer prices of the thermal units are in effect used to dispatch these units to produce the same output this set generated in the actual dispatch (total load – the output of the non-modeled units).

72 Bushnell and Saravia, p. 8. MCTHERMAL is therefore equivalent to THERMALP with the actual offer prices replaced with estimated marginal costs and actual unit availabilities. Thus, the model units are in effect dispatched to meet load based on their estimated marginal costs, taking the actual output of the non-modeled units as given with.

73 Bushnell and Saravia Tables 3, 4 and 5, pp. 14-16.

Figure 23



Were the assumptions of the simplified simulation model correct, the graph of ECP would lie exactly along the diagonal. Note this is error in the logic and detail of the model. The errors do not follow from random variation in the data. The only source of deviation from the diagonal would be consistent mistakes in the ISOs dispatch or consistent mistakes in the simulation model. The deviations from the diagonal summarize the errors in the model or the errors made by the ISO in finding the economic dispatch. The average absolute error in the monthly average is $5.01 with a standard deviation of $7.11. It is particularly noteworthy that in the several months portrayed in Table 22 in which the actual price considerably exceeded the price simulated based on estimated margin costs, the actual price also considerably exceeds the price simulated using actual offer prices. These differences suggest that the source of the gap between actual and simulated prices is in the simulation model, not in bidding behavior.

Similarly, under the simplifying assumptions of the static single-price simulation model, the actual output of modeled thermal units should be a simple subset of the aggregate supply curve of all offered units that produced the BIDP. Since the modeled thermal units exclude nuclear, small thermal and cogeneration units that are in the aggregate supply curve at their bid price, the modeled thermal units are a strict subset of all the units included in the supply curve.[74] Hence,

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[74] Bushnell and Saravia, pp. 9-11. In effect, THERMALP dispatches the thermal units to meet load based on the actual bids of the thermal units and taking the output of the hydro, small thermal and nuclear units as fixed at

the price using only the modeled thermal units cannot be greater than the price using all units. And to the extent that a non-modeled unit bid sets the clearing price in BIDP, the price using only the modeled thermal units could be less than the price from the aggregate supply curve. Thus:

$$\text{THERMALP} \leq \text{BIDP}.$$

Again, this relationship follows directly form the basic logic of the simulation model. If the simulation model is correct, the relationship should hold in every hour independent of the exercise of market power, the offer prices or the estimated marginal cost. Hence, this is another look at the accuracy of the simulation model and its simplifications against the logic of the actual dispatch with its many additional constraints. Figure 24 plots the relationship between the simulated price based on the actual offer prices[75] and actual output of the modeled units (THERMALP)[76] versus the simulated price based on the offer prices of both the thermal units and the non-modeled small thermal and nuclear units (BIDP).

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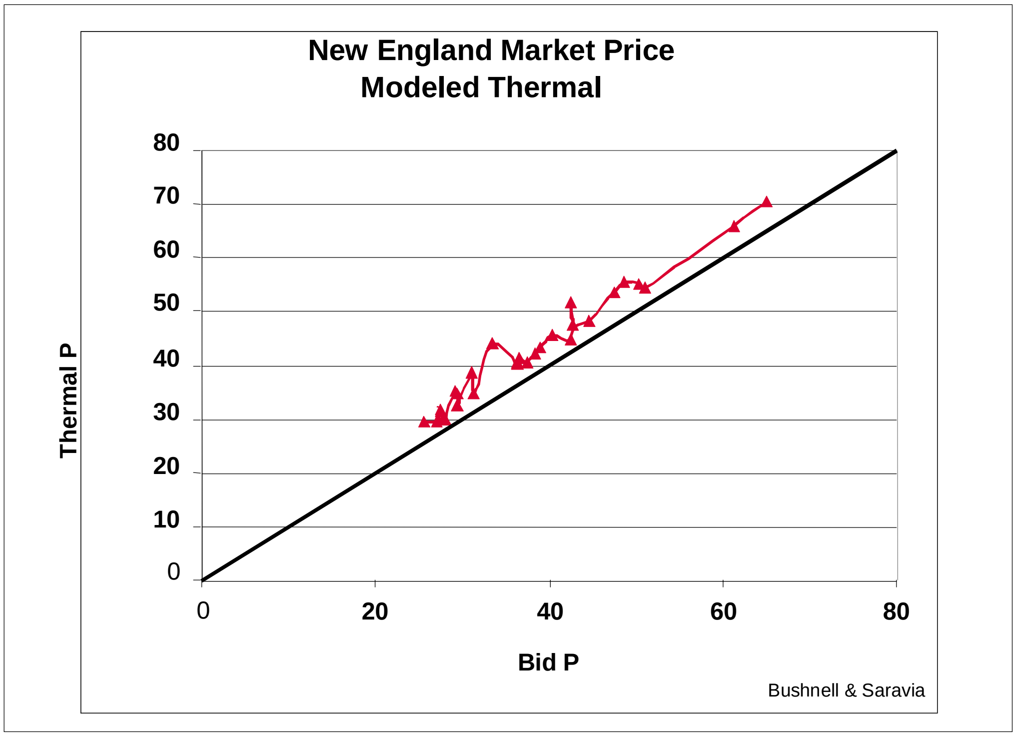
their actual output. Under the assumptions of the static single-price simulation model, the dispatch of the thermal units must be the same in the ECP, BIDP and THERMALP cases.

75 And, thus, also the actual availabilities.

76 As noted, this is equivalent to dispatching the modeled units to meet load taking the output of the non-model units as given.

Figure 24



Inspection of Figure 24 shows that the simulated price based on the actual offer prices and output of the modeled thermal units is never below the price simulated based on the supply curve using all the units.[77] The simulated price based on the actual output of the modeled units is thus always too high compared to the relationship dictated by the simulation assumptions, that all energy that is economic based on the offer price will be supplied to meet load. Bushnell and Saravia argue that the discrepancy between BIDP and THERMALP could be attributed to the assumptions in the static single-price simulation model that ignore transmission congestion or other reasons to dispatch out of merit as required in the actual dispatch (such as reserve and regulation requirements and ramp limits).[78] This is quite possible, but is only one potential source of error introduced by the simplifications in the static single-price simulation.[79]

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77 That is, the actual output of the non-modeled units at the actual price level must on balance be lower than the output of these units as calculated based on their actual bid curves.

78 Similarly, differences between prices simulated based on MCTHERMAL or THERMALP would be expected to exist as a result of NEPOOL's non-locational pricing system. Generators in constrained-up regions in NEPOOL are currently not paid the market-clearing price at their location, but are instead paid their bid. A competitive firm lacking market power should therefore submit bids reflecting the anticipated market clearing price at its location, rather than its costs. In a world of perfect information, this bidding behavior would not restrict output but would ensure that suppliers are paid the market price.

Moreover, if every supplier bid the market clearing price at its location, THERMALP would exceed MCTHERMAL, although the locational prices calculated based on the bids and marginal costs estimates were

In summary, the results of the Bushnell and Saravia study indicate that neither of the relationships implied by the simulation assumptions is satisfied. An important conclusion that follows from these results is that we would reject the hypothesis that the simulation model provides a close approximation of actual dispatch conditions and, therefore, reject the hypothesis that the model provides a reliable estimate of the competitive benchmark price. Thus, as Bushnell and Saravia suggest, the difference between the actual ECP and simulated MC may not arise from above cost bids, but from constraints present in the real world that are not in the simulation.

This is an important result, because it is a relatively straightforward test of the validity of the simulation model. The import of the work is that the simulation model contains substantial errors. The difference between the actual and simulated price could therefore arise from the real-world constraints omitted from the model in conjunction with purely competitive behavior, or the difference could arise from the exercise of market power by sellers that are able to raise prices because of constraints omitted from the model. Regardless of the reasons for the difference, the difference between the actual prices and those simulated by these kinds of models provides little information on the degree to which prices have been impacted by the exercise of market power, one simply cannot tell from these simulations. The error is larger than the effect being estimated.

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the same. This property was demonstrated for simulations of the PJM system back in 1996. LMP-based bids would raise the single stack price from $18.54 to $20.11, while leaving the underlying dispatch and LMP prices unchanged (see William W. Hogan, "Report on PJM Market Structure and Pricing Rules," December 31, 1996, particularly pp. 91-98).

[79] For example, differences could also arise because the actual output of units was reduced by real-time deratings or operating problems, or because the ISO failed to dispatch the unit despite it being in merit (during most of the study period ISO-NE was utilizing a telephone based dispatch).

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Table 25

Unit Profitability Analysis: Energy and AS Revenues (50% Spin/50% Non-Spin) from Base Case Simulation, Prices Capped at $750, Output Capped at Non-Derated Capacity

	Alamitos 1	Alamitos 2	Alamitos 3	Alamitos 4	El Segundo 1	El Segundo 2	El Segundo 3	El Segundo 4	Etiwanda 1	Etiwanda 2	Etiwanda 3	Etiwanda 4	Redondo Beach 5	Redondo Beach 6
6/1/2000	OFF	OFF	OFF	OFF	OFF	OFF	(22,656)	10,818	OFF	OFF	OFF	OFF	OFF	OFF
6/2/2000	OFF	OFF	OFF	OFF	OFF	OFF	(22,171)	5,213	OFF	OFF	OFF	OFF	OFF	OFF
6/3/2000	OFF	OFF	OFF	OFF	OFF	OFF	(23,287)	1,601	OFF	OFF	OFF	OFF	OFF	OFF
6/4/2000	OFF	OFF	OFF	OFF	OFF	OFF	(29,023)	(3,923)	OFF	OFF	OFF	OFF	OFF	OFF
6/5/2000	OFF	OFF	OFF	OFF	OFF	OFF	(19,544)	12,759	OFF	OFF	OFF	OFF	OFF	OFF
6/6/2000	OFF	OFF	(45,313)	(35,898)	OFF	OFF	(9,887)	21,382	OFF	OFF	(38,012)	(34,547)	OFF	OFF
6/7/2000	OFF	OFF	(46,995)	(35,775)	OFF	OFF	(4,803)	25,540	OFF	OFF	(39,216)	(34,309)	OFF	OFF
6/8/2000	OFF	OFF	(42,712)	(34,094)	OFF	OFF	(2,853)	26,452	OFF	OFF	(37,525)	(35,698)	OFF	OFF
6/9/2000	OFF	OFF	(34,695)	(26,902)	(25,478)	OFF	1,860	31,171	OFF	OFF	(32,204)	(30,200)	(34,331)	OFF
6/10/2000	OFF	OFF	OFF	OFF	OFF	OFF	(16,059)	11,427	OFF	OFF	OFF	OFF	OFF	OFF
6/11/2000	OFF	OFF	OFF	OFF	OFF	OFF	(31,266)	(5,444)	OFF	OFF	OFF	OFF	OFF	OFF
6/12/2000	OFF	OFF	(3,389)	6,029	OFF	OFF	2,149	23,456	OFF	OFF	(5,358)	(1,128)	OFF	OFF
6/13/2000	200,029	197,357	361,488	365,049	201,455	181,379	389,684	417,618	149,420	151,736	356,755	379,430	190,783	189,863
6/14/2000	585,409	613,605	1,145,721	1,143,497	615,943	566,759	1,235,612	1,258,240	458,140	459,478	1,139,576	1,136,345	604,492	604,244
6/15/2000	297,912	313,218	540,489	544,710	315,400	294,372	524,577	500,893	219,009	220,598	514,942	515,102	305,248	304,652
6/16/2000	OFF	OFF	64,070	72,268	OFF	OFF	21,526	36,475	OFF	OFF	54,921	69,657	OFF	OFF
6/17/2000	OFF	OFF	OFF	OFF	OFF	OFF	(28,571)	(993)	OFF	OFF	OFF	OFF	OFF	OFF
6/18/2000	OFF	OFF	OFF	OFF	OFF	OFF	(31,501)	(7,209)	OFF	OFF	OFF	OFF	OFF	OFF
6/19/2000	OFF	(24,398)	(36,970)	(27,977)	(22,826)	(27,501)	(6,987)	17,138	OFF	OFF	(32,117)	(27,888)	(32,557)	(33,169)
6/20/2000	OFF	(23,601)	(27,907)	(19,760)	(20,597)	(27,435)	12,610	44,781	OFF	OFF	(23,554)	(20,681)	(31,305)	(33,102)
6/21/2000	55,250	67,752	148,146	154,034	70,529	58,402	192,495	220,900	44,176	46,869	150,352	151,190	60,637	59,814
6/22/2000	354	9,318	(20,210)	(12,493)	10,697	5,933	13,497	45,049	4,986	(1,578)	(15,245)	5,304	1,585	879
6/23/2000	OFF	OFF	72,989	34,221	OFF	OFF	11,257	24,606	OFF	OFF	OFF	OFF	OFF	OFF
6/24/2000	OFF	OFF	OFF	OFF	OFF	OFF	(28,544)	5,034	OFF	OFF	OFF	OFF	OFF	OFF
6/25/2000	OFF	OFF	OFF	OFF	OFF	OFF	(26,918)	3,230	OFF	OFF	OFF	OFF	OFF	OFF
6/26/2000	513,787	540,865	1,015,136	1,014,094	539,173	498,592	1,100,098	1,124,289	403,532	404,851	1,010,860	1,008,307	530,949	530,863
6/27/2000	652,827	682,257	1,283,722	1,281,080	683,937	631,305	1,372,228	1,394,779	511,859	512,620	1,275,435	1,272,882	672,486	672,403
6/28/2000	597,523	626,318	1,173,376	1,171,384	624,681	578,203	1,266,982	1,294,281	468,708	469,472	1,166,994	1,164,687	613,490	616,116
6/29/2000	524,425	548,694	969,362	970,241	549,749	509,679	1,054,417	1,065,546	405,171	405,964	963,380	962,184	539,077	538,916
6/30/2000	68,987	52,944	71,259	79,389	55,075	74,738	36,355	44,022	39,545	41,205	55,794	57,988	45,702	57,006

"OFF" means the unit would not have been dispatched in any hour based on its full load dispatch price and the simulated price.

Profit calculations, by hour, summed over the day:

If Simulated Price >= Dispatch Price then Full Load Revenues minus Full Load Costs (average heat rate).

If Simulated Price < Dispatch Price then Min Block Revenues minus Min Block Costs (average heat rate) + AS Revenues (50% DA Spin, 50% DA Non-Spin)

Ramp Rate Assumptions: SCE Divestiture documents as Source: Alamitos 1-2, El Segundo 1-2, Redondo Beach 5-6 (3.50 MW/min); Alamitos 3-4 (6.40 MW/min); El Segundo 3 (6.70 MW/min). HESI as Source: Etiwanda 1-2, Etiwanda 3-4.