California Independent
System Operator Corporation

Assessment of MRTU Local Market Power Mitigation

prepared by

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I. Executive Summary

Background

Under MRTU, local market power mitigation (LMPM) will be based on a PJM-style approach, under which units that are dispatched for additional incremental energy to meet uncompetitive transmission constraints may have their bids mitigated to a Default Energy Bid (DEB).[1] The CAISO's February 2006 MRTU filing noted that LECG – a consulting firm hired to review the MRTU filing – expressed some concern that under this approach, generators within load pockets may still have the ability to profitably exercise local market power by economically withholding one or more lower cost generating units, so that prices are set by units with higher DEBs (such as Combustion Turbines with relatively high heat rates).[2] The CAISO's filing indicated that this issue would be analyzed in more detail in 2006 and that modifications would be proposed to the LMPM design if appropriate.

This report provides an assessment of the potential for the exercise of locational market power by economic withholding under the CAISO's proposed MRTU LMPM rules. In addition to examining the specific scenario described by LECG (i.e., a generator bidding so that MCPs were set by a high cost combustion turbine (CT) within the generators portfolio), the report examines more general strategies that might be used to exercise local market power through economic withholding. Specifically, although not all generators within the major load pockets in the CAISO have relatively high cost CTs in their portfolio, economic withholding may still be profitable under PJM-style mitigation rules if such bidding allows prices to be set by higher cost units owned by other generators or Frequently Mitigated Units (FMU) eligible for a $25 bid adder.

Methodology

The methodology used in this study is summarized below.

- The analysis of LMPM effectiveness is performed using PLEXOS for Power Systems (PLEXOS) market simulation software. Two basic variations of the CAISO grid are modeled in PLEXOS: a Competitive Constraints (CC) version of the model that includes only the major competitive constraints (such as Path 15, Path 26 and external inter-ties), and an All Constraints (AC) version that includes all transmission constraints.
- A series of data analysis routines was developed by CAISO's Department of Market Monitoring (DMM) staff to utilize the PLEXOS model to simulate the various

[1] The DEB may be based on a variety of options, ranging from heat-rate based marginal costs to MCP-based DEBs reflecting nodal MCPs during periods in which the unit was previously self-scheduled or cleared the market in-sequence.

[2] *Prepared Direct Testimony of Keith Casey*, pp. 64-67, included as Attachment K (Exhibit No. ISO-6) to the CAISO's February 9, 2006 MRTU filing.

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iterations of the PJM-style LMPM. The data analysis routines examine the output of the CC and AC PLEXOS model runs, and develop modified inputs that represent how bids would be mitigated under the proposed LMPM rules prior to running the Integrated Forward Market (IFM). These inputs are used in a final run of the AC version of the PLEXOS model (representing the final IFM), and another set of SAS routines are used to summarize and analyze these results.

- The study assumes a system load level of 43,190 MW, which represents are relatively high load hour even after considering potential load growth by the year 2008.
- Inputs for non-gas fired supply are also based on historical data for a recent high load hour (September 5, 2005 at 4:00 pm). Scheduled generation and scheduled imports are represented by zero-priced supply bids.[3] Real-time energy bids from these resources are represented as additional supply bids at the actual price.
- Bidding inputs for gas-fired units in a market baseline scenario are derived from heat-rate based marginal costs, plus an adder representing the average mark-up of each unit's real-time energy bids over marginal costs during the high load hours of summer 2006 (in $/MWh). These market baseline bids were used in each of the scenarios, except for gas units owned by the individual supplier whose ability to unilaterally exercise locational market power is being examined in the scenario.
- Within the CAISO system, six major suppliers own resources within the three major load pockets.[4] For each of these suppliers, a series of six different bidding scenarios was developed to represent different, increasing levels of economic withholding that might be employed in order to unilaterally exercise locational market power. For each of these scenarios, a different portion of the generator's capacity was allocated into three basic categories of bidding blocks: (1) low cost capacity bid at marginal cost, (2) capacity with high DEB (such as a relatively old CT or FMU) and (3) other capacity to be economically withheld by bidding at very high prices that would only clear the market if the supplier were pivotal in meeting local demand (i.e., just below the price cap of $400).
- Each of the bidding scenarios is simulated using the PLEXOS/SAS models, and results are used to identify the degree to which it may be profitable for each individual supplier to unilaterally exercise locational market power.

A more detailed description of each of these steps is provided in Section II. In addition, it should be noted that the basic modeling framework established through this study can be expanded and refined to provide more comprehensive analysis of the basic issues and areas of concern identified in this study.

[3] Actual metered supply generation from renewable, intermittent and QF suppliers are also represented as zero-priced "self-scheduled" generation.
[4] Suppliers F and E (San Diego); Suppliers A and B (Bay Area); and Suppliers C and D (LA Basin).

Summary of Study Results

The basic analysis described above was designed to provide an initial indication of the degree to which it may be profitable for major suppliers to unilaterally exercise locational market power under LMPM. Key findings of this analysis are summarized below.

- **Bay Area.** Since neither of the major suppliers in the Bay Area (Supplier A and Supplier B) has any relatively old high cost CTs in their portfolio, the specific scenario identified by LECG could not be assessed. Instead, similar bidding scenarios were developed assuming that the least efficient units in each of these suppliers' portfolios was a Frequently Mitigated Unit (FMU) eligible for a $25 bid adder. Results show that the CAISO's LMPM rules may effectively prevent one supplier (Supplier B) from exercising locational market power in this area. Meanwhile, results indicted that the other major supplier in the Bay Area (Supplier A) may find it profitable to unilaterally exercise market power by economically withholding capacity. Under the most profitable bidding scenario included in the study, this supplier's operating profits were increased by over 130 percent from a baseline reflecting historical bidding levels, while overall prices in the Bay Area were increased about 41 percent and overall system prices rose about 16 percent. However, close examination of these results indicates that these price increases do not result from the exercise of locational market power by Supplier A in the manner described by LECG, and instead result from more general forms of economic withholding by Supplier A and other suppliers incorporated in the scenario.[5] Moreover, sensitivity analysis indicates that under the assumption of more competitive bidding by the other major supplier in the Bay Area, Supplier A's ability to increase prices and profits by this bidding strategy is effectively limited or eliminated.
- **LA Basin.** Results suggest that only one of the major suppliers in the LA basin (Supplier C) may find it profitable to unilaterally exercise local market power by economically withholding capacity under the LMPM approach incorporated in MRTU. Again, since neither of these suppliers has any relatively old high cost CTs in their portfolio, the specific scenario identified by LECG could not be assessed. Instead, similar bidding scenarios were developed assuming that the least efficient steam turbine in each of these suppliers' portfolios was a Frequently Mitigated Unit (FMU) eligible for a $25 bid adder. Results of this initial analysis indicated that while each of these suppliers could unilaterally raise prices, it was only marginally profitable for Supplier C to do so, with a resulting price increase of only about 4 percent. These findings are consistent with the basic results of previous RMR and Local Resource Adequacy Requirements (LRAR) studies showing the LA basin to be the most competitive of the CAISO's three major load pockets. However, due to the abundance of steam units with relatively long unit commitment times and costs in this area, additional analysis that incorporates the daily unit commitment decisions may be warranted in this area.

[5] Since some suppliers bid significantly above marginal costs during high load hours of summer 2006, bidding inputs used in the market baseline scenario assume some economic withholding by other suppliers.

- **San Diego.** In the San Diego area, results suggest that under the load and supply conditions examined in this study, neither of the major suppliers (Supplier E and Supplier F) may find it profitable to employ the type of economic withholding strategy identified by LECG. However, these results are being reviewed to ensure that modeling assumptions accurately reflect all reliability requirements and constraints that may actually be enforced in the nodal market software under MRTU.[6] Both of these suppliers have one or more relatively old, high cost CTs in their portfolio, which may be used to set relatively high prices even if LMPM price mitigation occurs, as described under the specific scenario identified by LECG. Currently, all these units are under RMR contracts, which could limit the ability to exercise market power under LMPM. However, locational market power could remain a concern under MRTU if these RMR contracts are replaced with Resource Adequacy (RA) contracts, which are not coupled with tolling agreements or some other mechanism that limits or removes the ability of the unit owners to set the energy bid price of these units.

Overall results of this study were somewhat surprising in terms of how limited the potential for locational market power was found to be. Thus, additional review of the reasons for these results and sensitivity analysis of different assumptions may be warranted, as discussed in the final section of this Executive Summary.

At the same time, these results do not indicate that an alternative, indirect New York-style LMPM would be more effective than the direct, PJM-style LMPM approach incorporated in the CAISO's current MRTU market design. For example, LMPM rules previously considered for the CAISO if a New York-style approach was adopted – which were based on FERC-approved rule in the New York ISO – would have allowed prices in load pockets to rise by up to the lower of $10/MWh or 20 percent due to locational market power before LMPM provisions would limit bids and prices. As discussed on the preceding page, while one scenario examined in this analysis resulted in price increases greater than this $10/MWh or 20 percent threshold, it appears that these price increases do not result from the exercise of locational market power, and instead result from more general forms of economic withholding by multiple suppliers that would not be prevented by New York-style LMPM rules.

Further Analysis

The basic modeling framework established through this study can be expanded and refined to provide more comprehensive analysis of the basic issues and areas of concern identified in this study. Potential future enhancements and areas of study include the following:

- *Transmission model review.* Continued review of constraints in the PLEXOS model to ensure that the model reasonably reflects actual constraints that will be

[6] Based on discussions with operations engineering and transmission planning staff, it appears that, at a minimum, the PLEXOS model being used in this analysis does not incorporate voltage support requirements that would typically require multiple units within San Diego to be on-line. Under MRTU, such requirements may be met by manual dispatch of RMR units.

incorporated in the CAISO systems used to perform LMPM, the IFM and Security Constrained Unit Commitment (SCUC) under MRTU.

- *Review and sensitivity analysis of Local Market Power Mitigation Assumptions.* One of the key assumptions in this analysis is that all key paths that constrain supply into load pockets will be deemed uncompetitive under the CAISO Competitive Path Assessment (CPA). In addition, the study assumes that the DEB for all units (except FMUs) will be based on marginal costs. In practice, DEBs could be significantly higher under the LMP-based option for DEBs, which is based on an average of the lowest quartile of LMPs at the unit's location during time periods when the unit is in operation. Thus, additional analysis of these key assumptions may be warranted. However, at this time, it would be very difficult to assess the level of DEBs that may result from the LMP-based option in a meaningful way due to the large number of assumptions that need to be made in such analysis. In addition, it should be noted that high LMP-based DEBs would undermine the effectiveness of both the PJM and New York-style LMPM approaches.

- *Incorporation of daily unit commitment decisions and costs*. The analysis in this study was based on an optimized dispatch of energy bids for a single hour, with the profitability of different bidding strategies being based only on marginal generating costs (i.e. excluding any startup or minimum load costs). Under MRTU, however, the IFM optimization will be based on bids for energy, startup and minimum load over a 24 hour period, and generators' scheduling and bidding practices will be affected by the overall profitability of different strategies over a similar 24 hour operating period. Incorporating of these daily unit commitment decisions and costs into the model would provide a more realistic assessment of the potential profitability of different biding strategies. Initial sensitivity analysis indicates that incorporating these factors into the analysis may increase the profitability of economic withholding relative to more competitive bidding strategies.

- *Analysis spanning a broader time period and range of system conditions*. As noted above, this analysis was based on conditions representing a relatively high load day and hour, in order to provide an indication of the ability to exercise locational market power when this would most likely be successful. However, sensitivity analysis of other system load conditions would provide a more robust assessment of this issue. Although it may not be necessary or feasible to perform extensive analysis of a full 365 day period, some methods may be developed to annualize results in order to provide a better indication of results in the context of overall market costs and prices. For instance, a sampling of different day types can be analyzed and these results can be weighted to annualize overall results.

- *Refinement of Bidding Scenarios.* The relatively simple bidding scenarios utilized in this study may be refined to identify and test other bidding strategies that may be more profitable than the basic strategy identified by LECG. For example, search methods might be developed to identify more profitable strategies within the general range examined in this study. However, unless other system conditions or model modifications are identified that would significantly alter the basic findings of this analysis, it does not appear that more refined bidding strategies would result in different conclusions.

- *Duopolistic Bidding.* As described above, the bulk of the generating resources in each of the three major load pockets in the CAISO system are owned by two major suppliers. Under such market conditions, duopolistic bidding behavior is a logical concern. Although a more general analysis of locational market power is beyond the scope of this study, the basic model and methodology used in this study could be applied to examine the potential for duopolistic bidding patterns.

Section II of this report provides a more detailed description of the methodology used in this study. Section III provides a summary and discussion of study results. Section IV provides a summary of the report's overall findings and conclusions.

II. Methodology

1. Introduction

Under MRTU, a Local Market Power Mitigation (LMPM) process is executed before the day-ahead (IFM) and real-time market runs to determine reliability requirements and mitigate local market power exercised by generator merchants. In order to simulate the process and evaluate its effectiveness in market power mitigation, a procedure was developed in a production simulation tool using the CAISO full network model, generator bidding data, load forecast, and mitigation engine using in-house developed SAS programs.

2. Simulation Tool & Parameters

The PLEXOS market simulation tool, version 4.865 R12 Gold, is used for the analysis. The simulation takes a DC approach in arriving at a power flow solution and computing Locational Marginal Price, as follows: 1) MW flow will be computed, 2) impact on the transmission network due to power injection and withdrawal by the load is based on linear transfer distribution factor (TDF) and 3) no voltage nor MVar flow will be provided. Losses are not modeled in the current study. Unless otherwise modified, the model inputs were based on actual system conditions on September 5, 2005 at 4:00 pm.

3. Description of the Model

The primary source is the full network model from the CAISO's LMP Study 3B (PLEXOS format), with the forecasted network, load conditions in 2006 as well as internal interface and nomogram constraints adjusted to expected 2006 values. It consists of 19 regions, 3,800 bus nodes, 5,040 branches and transformers (60KV – 500KV), and 664 generating units. It models additional generation listed in the CAISO's Controlled Grid Study Plan and removes those to be retired.

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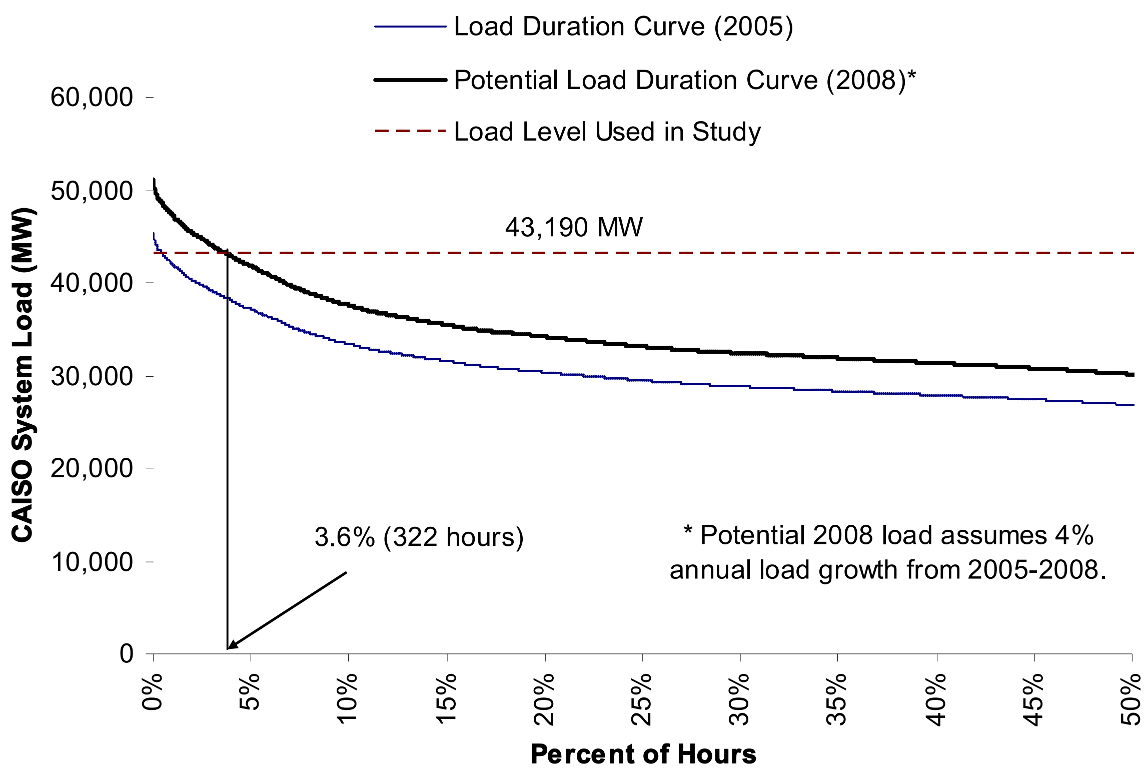
3.1 Load and Demand

The participation of loads within load aggregation areas is based on a static distribution contained in the network model. The study assumes a system load level of 43,190 MW. Figure 1 compares this load level to a potential load duration curve for 2008, derived from actual 2005 loads under the assumption of a 4 percent annual growth rate. As shown in Figure 1, this load level corresponds the 322nd highest load hour of this potential 2008 load duration curve. Thus, the 43,190 MW level used in the study exceeds potential loads during about 96.4 percent of hours and is lower than potential loads during only about 3.6 percent of hours of this potential 2008 load duration curve.

The regional load is modeled as inelastic demand and therefore a price-taker. Pump-storage units and exports are modeled as demand using 2004 historical hour-ahead (HA) final MW schedule and high price ($5,000/MWh) as the first block and the real-time (RT) incremental (INC) bids as the second block that will respond to the market price signal.

Figure 1. Comparison of Load Level Used in Study with CAISO System Load Duration Curves



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3.2 Monitored Elements

Reliable operation of the transmission grid is achieved by monitoring transmission facilities under various criteria to meet the specific reliability need. Actual hourly import limits from current market data, and internal network ratings including critical constraints implemented in the CAISO's operating procedures (e.g., simultaneous flow limits and nomograms), are employed in the model.

- *Transmission line*. Normal thermal ratings are enforced under normal conditions as opposed to emergent/contingent ratings under contingency. In real-time operation, the rating or its total transfer capacity (TTC) is reduced to the respective lower limits imposed by voltage stability, dynamic stability or increased ambient temperature.
- *Interface.* Defined as branch groups that monitor grandfathered paths. They are treated as competitive paths by default. There are 40 interfaces being monitored.
- *Nomogram.* Empirical operation procedures that keep combination of line flows, resource injection, load withdrawal with different flow coefficient under a specified value to ensure reliable grid operation. This is modeled as a constraint in the PLEXOS simulation tool.
- *Operating Guide.* An engineering proven procedure to reconfigure transmission facilities or re-dispatch generating units to enforce line flow under a specified limit to avoid overloads or voltage problems under normal or contingent conditions. It is modeled as a constraint in the PLEXOS simulation tool. There are a total of 62 constraints defined for monitoring and limits are subject to change due to the nature of power system dynamic conditions.
- *Contingency Analysis*. A preventive procedure to ensure a "secure" operating condition that can withstand the next possible worst contingency by adjusting initial feasible and most economic dispatch solutions towards feasible security-constraint ones. This is not modeled in the current analysis.

3.3 Generating Units and Supply

There are a total of 664 generating units, including peaker, thermal, hydro, nuclear, biomass, cogeneration, geothermal, solar, and wind. Other supplies such as imports of external resources via inter-tie are also modeled as generating resources. As the unit commitment and forced outages are not modeled, all gas-fired capacity is assumed to be available.

In the analysis, units consuming natural gas or oil fuel are the main focus of concern in exercising market power and are therefore simulated with multiple scenarios using various offer prices. This is explained in detail in Section 4, "Thermal Generating Unit Offer Price and Quantity."

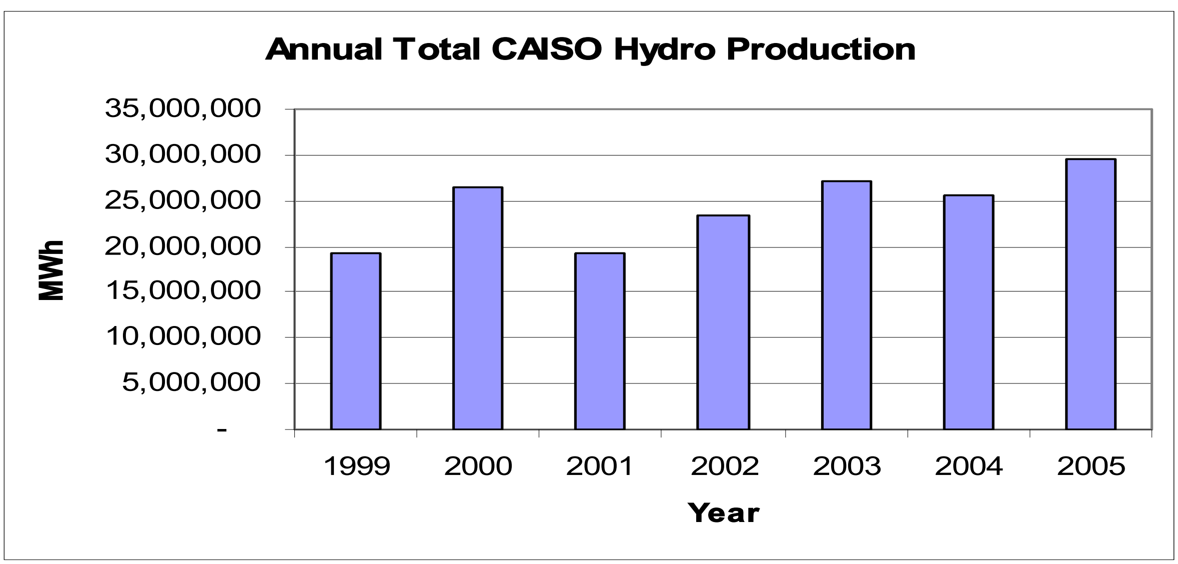
For the non-gas and non-oil units (except hydro plants), their actual metered generation output as of September 5, 2005 at 4:00 pm are used as the only quantity offered with zero offer price such that the output level can be honored by simulation dispatch.

External resources are modeled using their historical inter-tie bids. Each node outside CAISO on the tie line is considered to be both a generation node (for the purpose of modeling imports to the CAISO) and a load node (for the purpose of modeling exports from the CAISO). For a gen node, a multi-step offer quantity/offer price curve is established for the generation node for each hour by compiling the 2004 hourly HA final *import* schedule and RT inter-tie *INC* bids (note that the HA final import schedule has zero price) to use as the 2006 inter-tie generation node offer quantity/offer price associated with the Medium Hydro scenario (see the section below); for a load node, a multi-step bid quantity/bid price curve is established by compiling the 2004 HA final *export* schedule and the RT inter-tie *DEC* bids (note the HA final export schedule has a very high price such as $5,000/MWh to make sure the HA export schedules will be honored in PLEXOS) to use as the 2006 inter-tie load node bid quantity/bid price associated with the Medium Hydro scenario.

In the analysis, the energy production from hydro plants in year 2004 was selected as being representative of a medium hydro capacity year, as shown in Figure 2 below. However, comparisons of hydro schedules and bids used in the model (September 5, 2004 at 4:00 pm) with the hydro data for the hour upon which other data are based in this analysis (September 5, 2006 at 4:00 pm) showed that the supply of hydro energy was roughly the same in both of these specific hours.

Hydro generation units are assumed to bid into the market with a 2-block bid curve. Hydro units' economic dispatch is modeled by using the HA final schedule and RT bids of 2004 from the CAISO hydro units (including hydro dispatchable, hydro, pump storage units, etc).

Figure 2. Annual CAISO Hydro Production (1999-2005)



3.4 Transmission Network

A 2006 planning networks topology used in CAISO's LMP Study 3B was implemented in PLEXOS for this analysis. The network is a projected 2006 system condition that incorporates generation planned outages and transmission outages for 500 kV lines and 500-to-220 kV transformers. The network is "open loop" to match the initial MRTU implementation. To create the "open loop" network model, network components beyond the inter-tie scheduling points have been deleted from the model. 2004 hour-ahead path ratings, without adjustment for ETC capacity, plus updated internal interface constraints were implemented in the model.

4. Thermal Generating Unit Offer Price and Quantity

The generator unit offer curve is formed by piece-wise linear blocks that are monotonically non-decreasing with the MW on the first point representing the generator minimum MW output and the last one the maximum output.

For units consuming natural gas or oil as fuel, incremental heat rate points (Btu/kWh) for each MW output level are provided as given inputs and various offer curves will be constructed accordingly for use in different modeling scenarios. The following four different bid curves were developed for each gas or oil unit:

- Marginal Cost Bid
- Default Energy Bid
- Marginal Cost Based Market Bid
- Historical Bid Based Market Bid

4.1 Marginal Cost Bid

Incremental heat rate curve (Btu/kWh) for each MW output level is computed and constructed based on provided average heat points and is adjusted if necessary to obey monotonicity. A unit technology-specific cap is imposed on the unit incremental heat rate during the adjustment: 8,500 Btu/kWh for combined-cycle units; 12,000 Btu/kWh for steam turbine; 17,000 Btu/kWh for gas turbine. The adjusted incremental heat rate curve forms the base of the default Marginal Cost Bid, computed as follows:

Marginal Cost ($/MWh) = Incremental heat rate x fuel price + VOM

Where:

- Fuel price is assumed to be $6.35/MMBtu for natural gas and a high price of $16/MMBtu for oil;
- VOM (Various Operation & Maintenance) cost is assumed to be $4/MWh for gas turbine and $2/MWh for combined-cycle and steam turbine units.

4.2 Default Energy Bid (DEB)

As a default, the DEB is set to the Marginal Cost Bid for all units except for RMR Condition 2 units and Frequently Mitigated Units (FMU). For RMR Condition 2 units, the DEB is set to the Schedule M rate that is average production cost at full output; for FMUs, an adder of $25 is applied to its marginal cost, as follows:

RMR Condition 2

Schedule M Rate = Average Heat Rate (at full MW output) x fuel price + VOM

FMU

DEB = Marginal Cost + $25

4.3 Marginal Cost Based Market Bid

The Market Bid is simply computed as inflating the Marginal Cost Bid by 120 percent except for RMR Condition 2 units. For RMR Condition 2 units, Schedule M rate is employed as their offer bid into the market.

4.4 Historical Bid Based Market Bids

Bidding inputs for gas-fired units in the "market baseline" scenario used in this study are derived from heat-rate based marginal costs, plus an "adder" representing the average mark-up of each unit's real-time energy bids over marginal costs during high load hours of summer 2006 (in $/MWh).

The following steps were used to derive historical bid-based market bids, reflecting the average mark-up over marginal costs included in real-time energy bids submitted for each unit during the summer of 2006.

- Data used in the analysis include all real-time energy bids submitted for Hours Ending 14-19 on weekdays between June 1 and August 25, 2005.
- Each unit's operating range from Pmin to Pmax was divided into 10 segments of equal length to obtain 11 boundary points.
- The corresponding bid price and short-run marginal cost for these 10 segments was calculated using the bid price and short-run marginal cost for the point representing the upper range of each segment. For example, the marginal cost for a unit's first bid segment was based on the unit's incremental heat rate at the second of the unit's 11 operating points. If the unit's output at each point was not bid into the real-time market (as a result of the unit being off-line or having an hour-ahead energy schedule), the hour was not included in the analysis.

- For each of these 10 segments (*mw*), the mark-up for each unit (*g*) for each hour (*t*) is calculated as:
  - $\text{Mark-up}_{g,mw,t}$ = Bid Price $_{g,mw.t}$ – Short Run Marginal Cost $_{g,mw,t}$
- The average mark-up for each unit *g* was then calculated for all hours in the time period used in the analysis (Hours Ending 14-19, weekdays between June 1 and August 25, 2006).
- The average short-run marginal cost for each unit *g* was then also calculated for all hours in the time period used in the analysis. Since schedules and bids for non-gas fired units are based on data for September 5, 2005, marginal costs calculated for each unit based on actual spot market gas prices in summer 2006 were normalized to the spot market gas price on September 5, 2005.
- Historical bid-based market bids for each operating segment (*mw*) for each unit (*g*) were calculated as follows:
  - $\text{Historical Bid}_{g,mw}$ = Avg. Mark-up $_{g,mw}$ + Normalized Avg. Short Run Marginal Cost $_{g,mw}$
- Finally, the resulting bid curves were adjusted at these 11 points to be monotonically non-decreasing, starting from Pmax to Pmin.

4.5 Reliability Must-Run (RMR) Unit Condition

A unit can be classified as an RMR Condition 1 or Condition 2 unit depending on the reliability-related study that determines a unit's criticality in meeting reliability needs such as voltage support or local constraint relief. Current RMR condition status for each unit is provided by the latest local reliability study and will affect the offer prices RMR units can bid into the market.

5. Competitive Paths

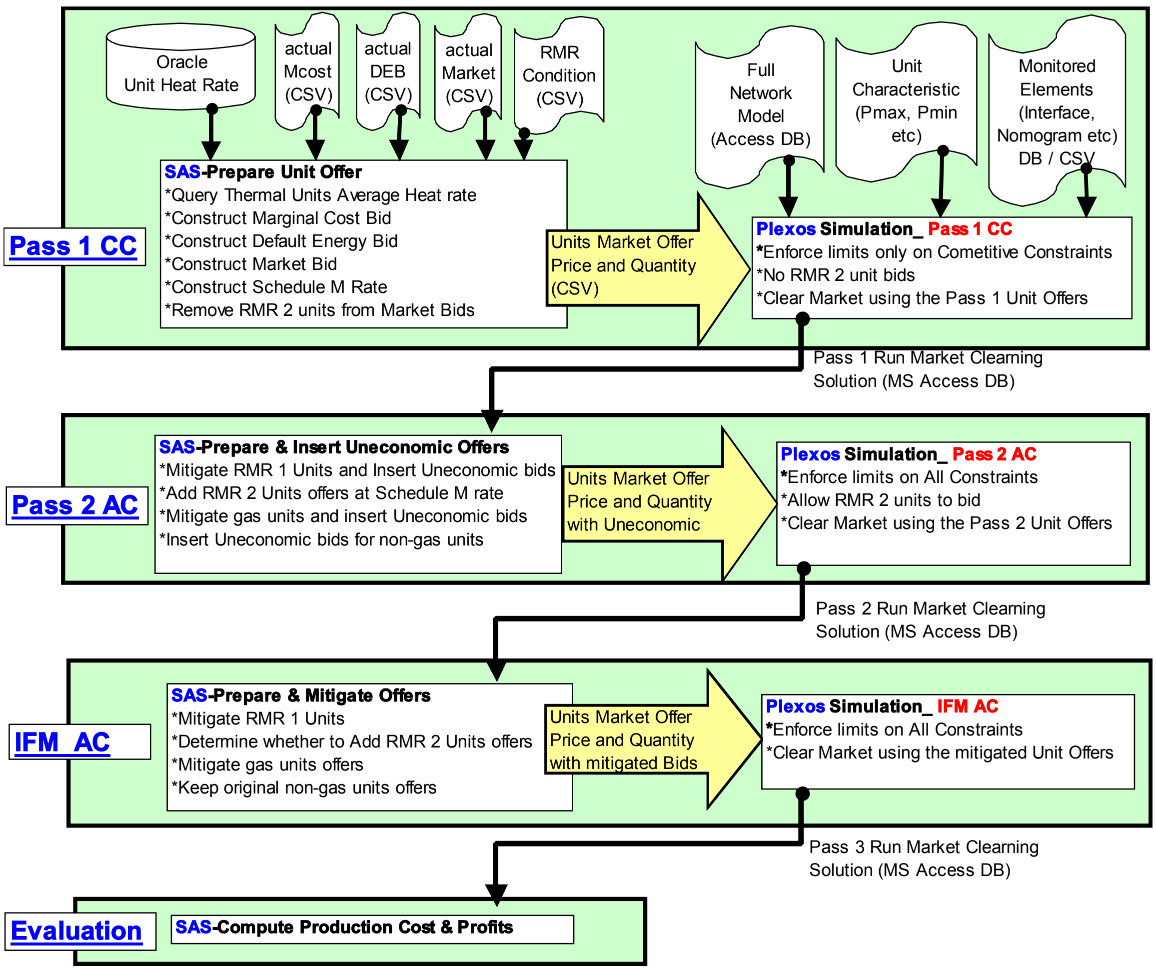
In the LMPM process, transmission constraints or paths are broken down into two categories: competitive paths or uncompetitive paths. The CAISO has adopted a Competitive Path Assessment (CPA) methodology to determine a list of competitive paths based on a "3-pivotal-supplier" test. The underlying assumption or goal of this test is that generators will not have market power to cause congestion on competitive paths or significantly increase market prices due to congestion on these paths. At the time the analysis was conducted, the CPA study had not been completed. As a result, the list of competitive paths for this analysis is set to current inter-zonal paths.

6. Local Market Power Mitigation Process and Rules

The implementation of the LMPM process consists of the PLEXOS market simulation tool that clears the market as well as reporting the market clearing solution and of a set of data processing routines developed in SAS[7] that act as the mitigation engine for different stages of Pass runs, as shown in the flow diagram in Figure 3.

The rules employed by the LMPM process are summarized in Table 1, and are illustrated in Figure 4.

Figure 3. Simulation of MRTU LMPM in Using PLEXOS/SAS Routines



[7] SAS (www.SAS.com) is a statistical analysis software program.

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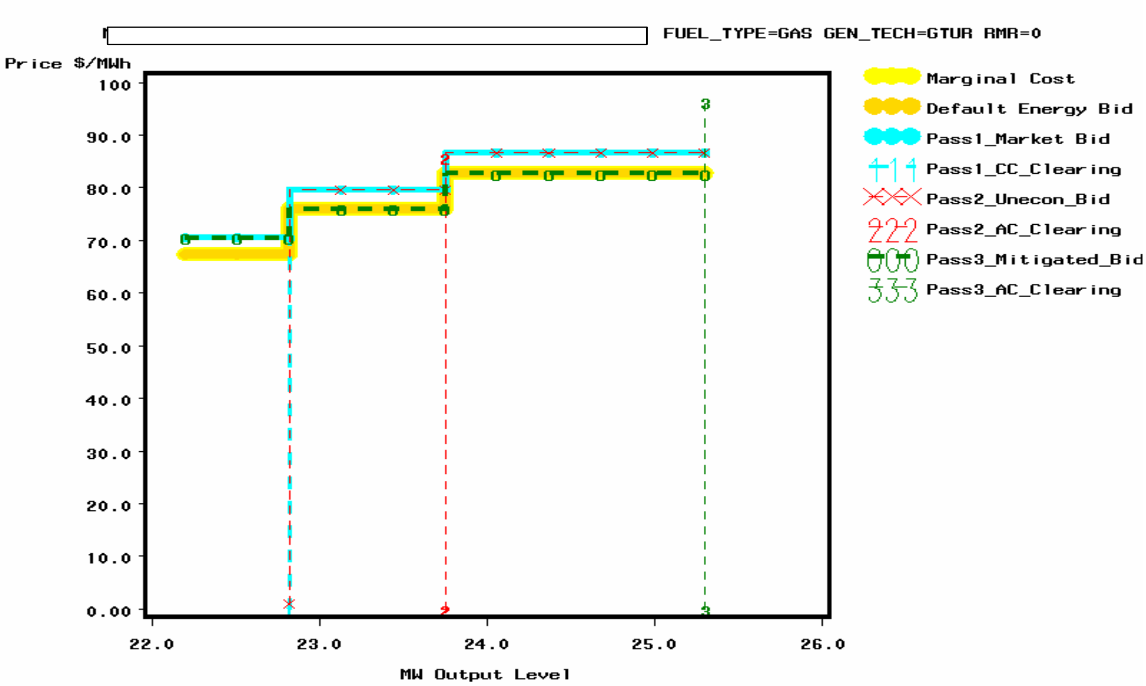
Table 1. LMPM Rules Incorporated in PLEXOS/SAS Model

	Pass 1 CC (Competive Constraint)	Pass 2 AC (All Constraints)	IFM AC _ mitigated (Integrated Forward Market)
RMR 1	Market Bid	If MCQ1 = 0 -Use MCost	If deltaMCQ = 0 -keep market bid
		If MCQ1> 0 -$-999 P for Q <=MCQ1 -mitigate Mkt bid P for Q > MCQ1: max{ min[mkt bid, MCost], P_MCQ1}	If deltaMCQ > 0 -keep P for Q <=MCQ1 -mitigate Mkt bid P for Q > MCQ1: max{ min[mkt bid, MCost], P_MCQ1}
RMR 2	No bid	Schedule M	If MCQ2 = 0 -no bid
			If MCQ2 > 0 -keep Schedule M
Residual Supply Units (gas)	Market Bid	If MCQ1 = 0 -keep Market Bid	If deltaMCQ = 0 -keep market bid
		If MCQ1 > 0 -$-999 P for Q <=MCQ1 -keep Mkt bid on Q > MCQ1	If deltaMCQ > 0 -keep P for Q <=MCQ1 -mitigate Mkt bid P for Q > MCQ1: max{ min[mkt bid, DEB], P_MCQ1}
Other non-gas	actual bid	If MCQ1 = 0 -Keep actual Bid	-keep acutal bid
		If MCQ1 > 0 -$-9999 P for Q <=MCQ1 -keep actual bid on Q > MCQ1	

Acronym	Description
P	Offer/Bid Price ($/MWh)
Q	Offer/Bid Quantity (MW)
MCQ1	Market Cleared Quantity (MW) Pass 1 CC
MCQ2	Market Cleared Quantity (MW) Pass 2 AC
P_MCQ1	Offer/Bid Price ($/MWh) for MCQ1
deltaMCQ	MCQ2 - MCQ1
MCost	Maginal Cost
Schedule M	average Heat Rate(at full MW output) * fuel price
DEB	Default Energy Bid

Figure 4. LMPM Rules Incorporated in PLEXOS/SAS Model



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7. Individual Supplier Bidding Strategies

Within the CAISO system, six major suppliers own resources within the three major load pockets.[8] For each of these suppliers, a series of five to seven different bidding scenarios were developed to represent different, increasing levels of economic withholding that might be employed in order to unilaterally exercise locational market power.

For each of these scenarios, a different portion of the generator's capacity was allocated into three basic categories of bidding blocks:

1) Low cost capacity bid at marginal cost,
2) Capacity with high DEB (such as a relatively old CT or FMU), and
3) Other capacity to be economically withheld by bidding at very high prices that would only clear the market if the supplier were pivotal in meeting local demand (i.e., just below the price cap of $400).

Different scenarios – representing varying levels of economic withholding – were developed by iteratively shifting additional units from the first block (low cost capacity bid at marginal cost) to the third block (capacity economically withheld). Each bidding block represented one to two generating units with similar operating costs, or a total of about 200 to 400 MW per block. Consequently, the specific number of scenarios developed for each supplier depended on the total amount of generation owned by each supplier and the size of the units in the supplier's portfolio.

Figures 5 through 9 provide an illustrative example of a series of such scenarios.

[8] Supplier F and Supplier E (San Diego); Supplier A and Supplier B (Bay Area); and Supplier C and Supplier D (LA Basin).

Figure 5. Illustrative Bidding Scenario 1 (Competitive Baseline)

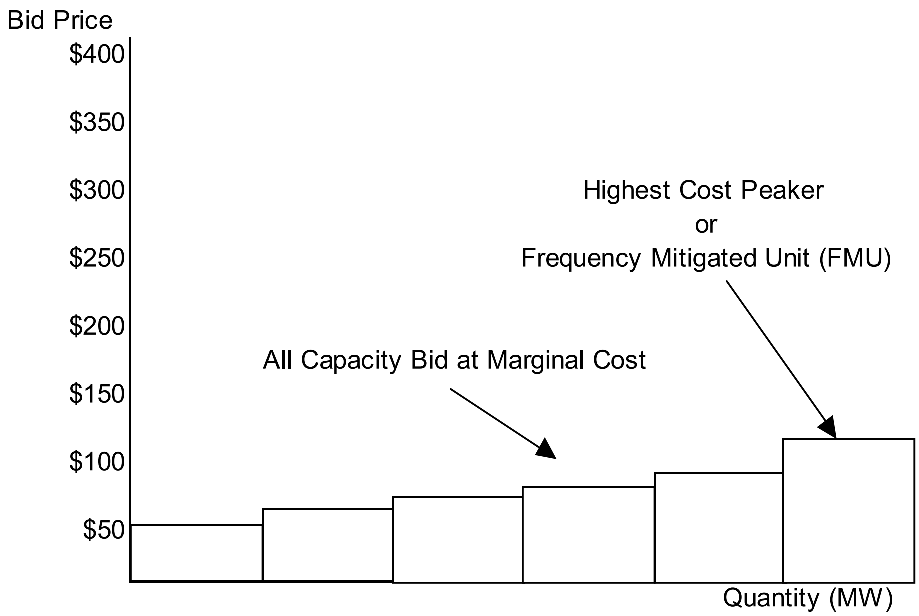


Figure 6. Illustrative Bidding Scenario 2 (Economic Withholding)

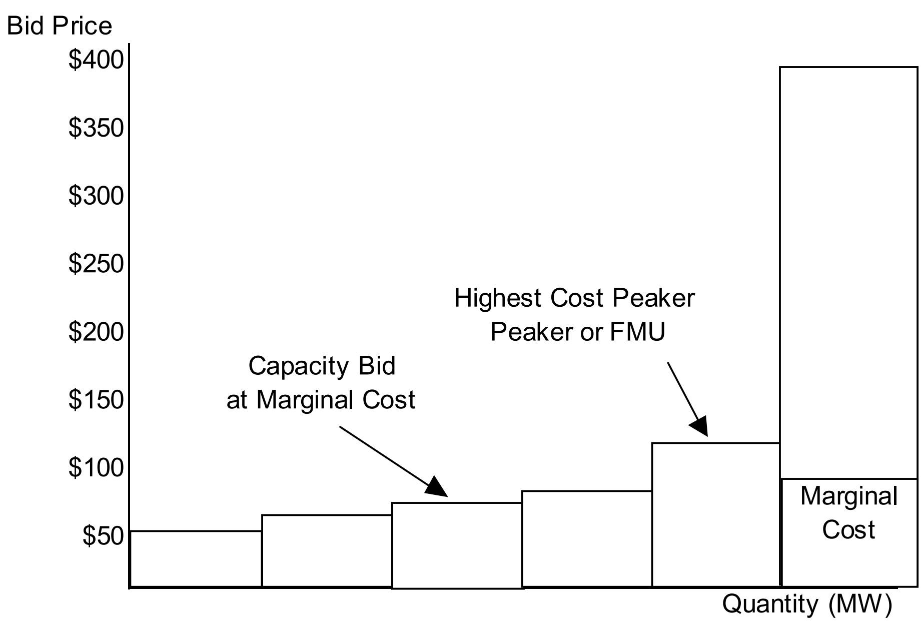


Figure 7. Illustrative Bidding Scenario 3 (Economic Withholding)

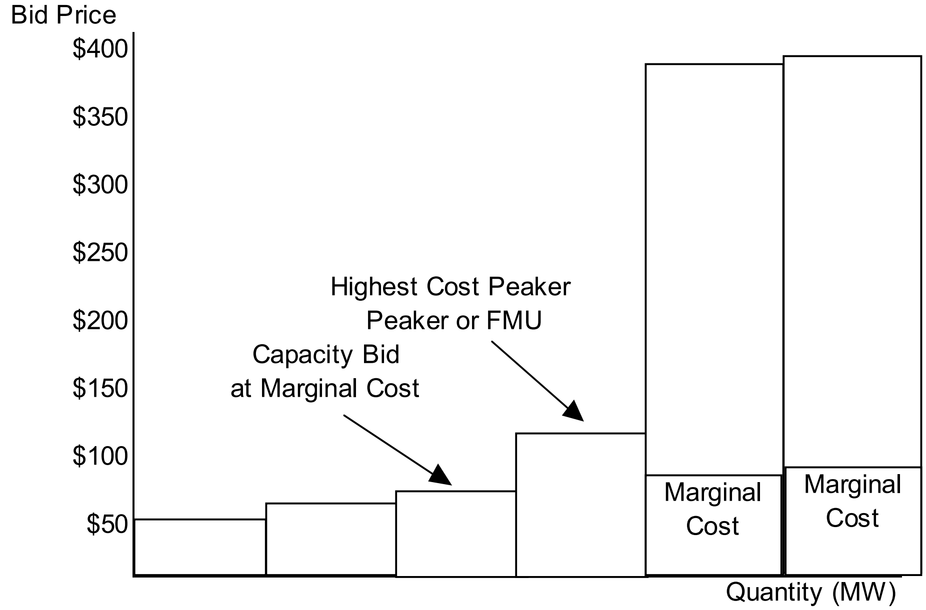


Figure 8. Illustrative Bidding Scenario 4 (Economic Withholding)

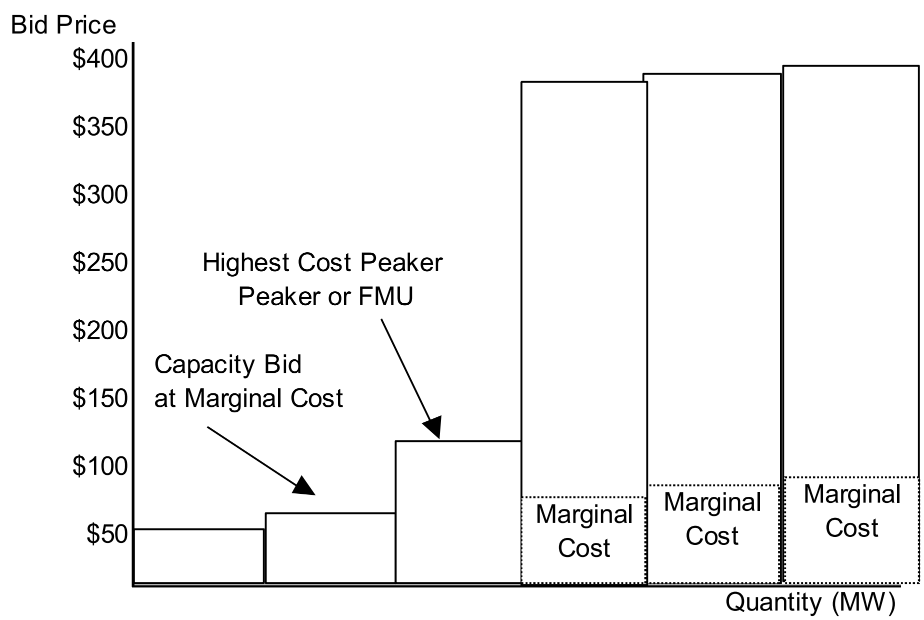
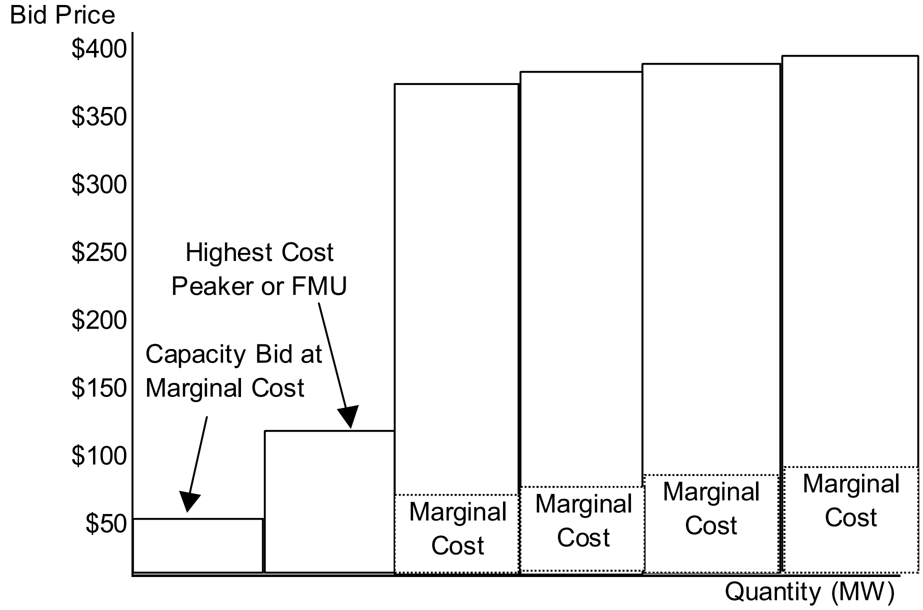


Figure 9. Illustrative Bidding Scenario 5 (Economic Withholding)



8. Profitability of Alternative Bidding Strategies

Each of the bidding scenarios is then simulated using the PLEXOS/SAS models, and results are used to identify the degree to which it may be profitable for each individual supplier to unilaterally exercise locational market power. The analysis in this study was based on an optimized dispatch of energy bids for a single hour, with the profitability of different bidding strategies being based only on marginal generating costs (i.e. excluding any startup or minimum load costs).

Under MRTU, however, the IFM optimization will be based on bids for energy, startup and minimum load over a 24 hour period, and generators' scheduling and bidding practices will be affected by the overall profitability of different strategies over a similar 24 hour operating period. Incorporating of these daily unit commitment decisions and costs into the model would provide a more realistic assessment of the potential profitability of different biding strategies. DMM is currently testing the unit commitment features of the Plexos software, and developing the additional data inputs and modeling changes necessary to utilize the model to simulate the type of 24 hour optimization upon which the IFM will be based.

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III. Results

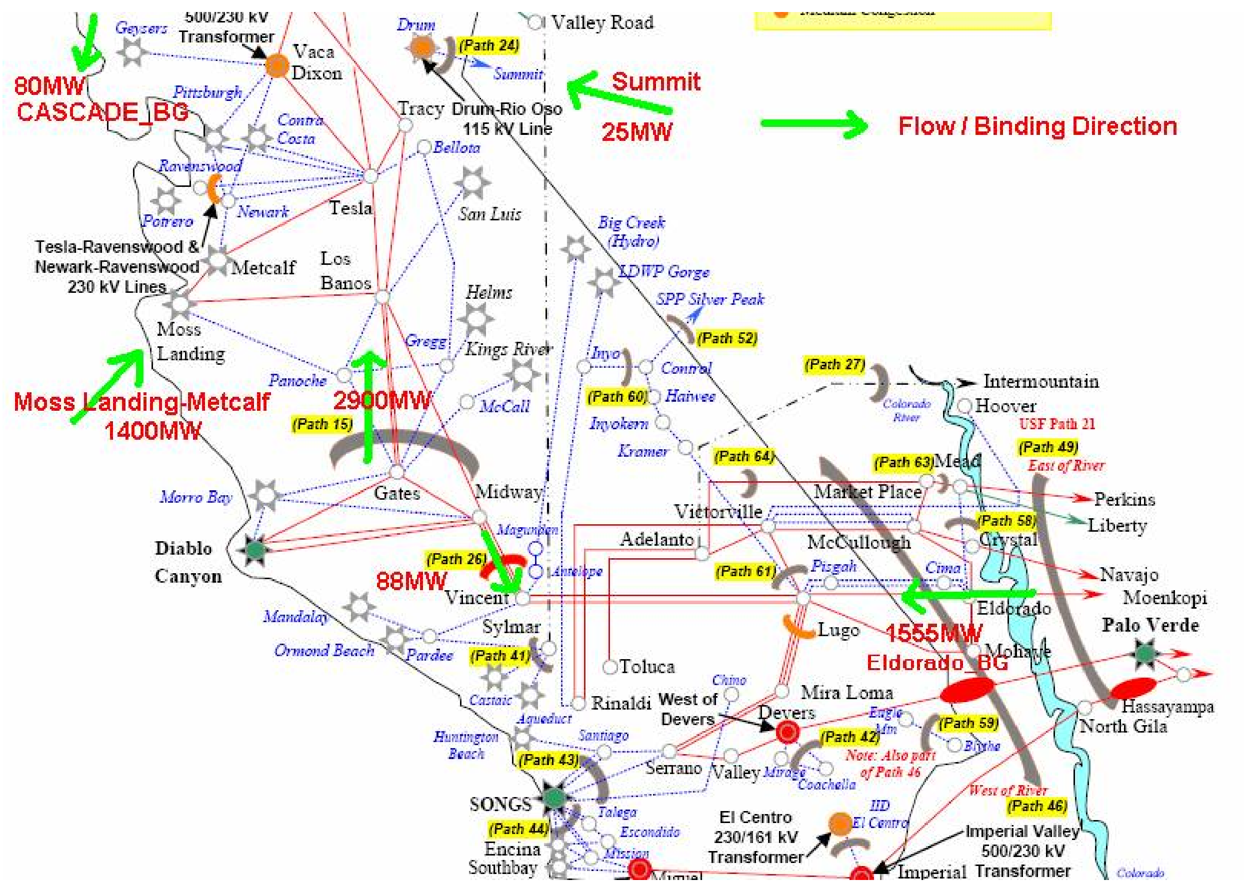
1. Congestion Patterns

Under the historical scenario, there are four binding constraints causing a variance in CAISO spatial LMPs:

- CASCADE_BG, rating of 80MW in a North-to-South binding direction
- Summit_BG, rating of 25MW in an East-to-West binding direction
- Moss Landing-Metcalf constraint, rating of 1,400MW in a South-to-North binding direction into San Francisco bay area
- Eldorado_BG, rating of 1,555MW in an East-to-West direction

The existence of these binding constraints causes lowest LMP in Arizona, moderate in Southern CA, and highest in Northern CA. The major flows and binding constraints are depicted by green arrows in Figure 10 below.

Figure 10



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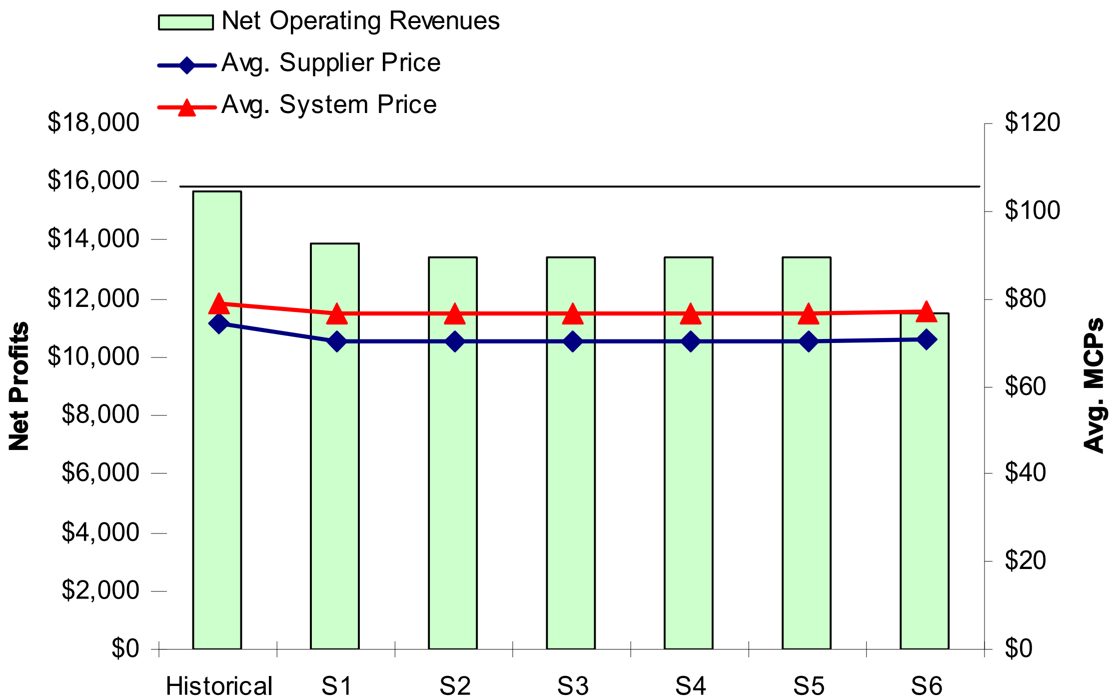
2. Local Area Results

The remainder of this section provides a detailed discussion of the results for each of the six suppliers within the three local pockets examined in this study. Section IV provides a summary of the results for each of the three areas.

San Diego – Supplier E

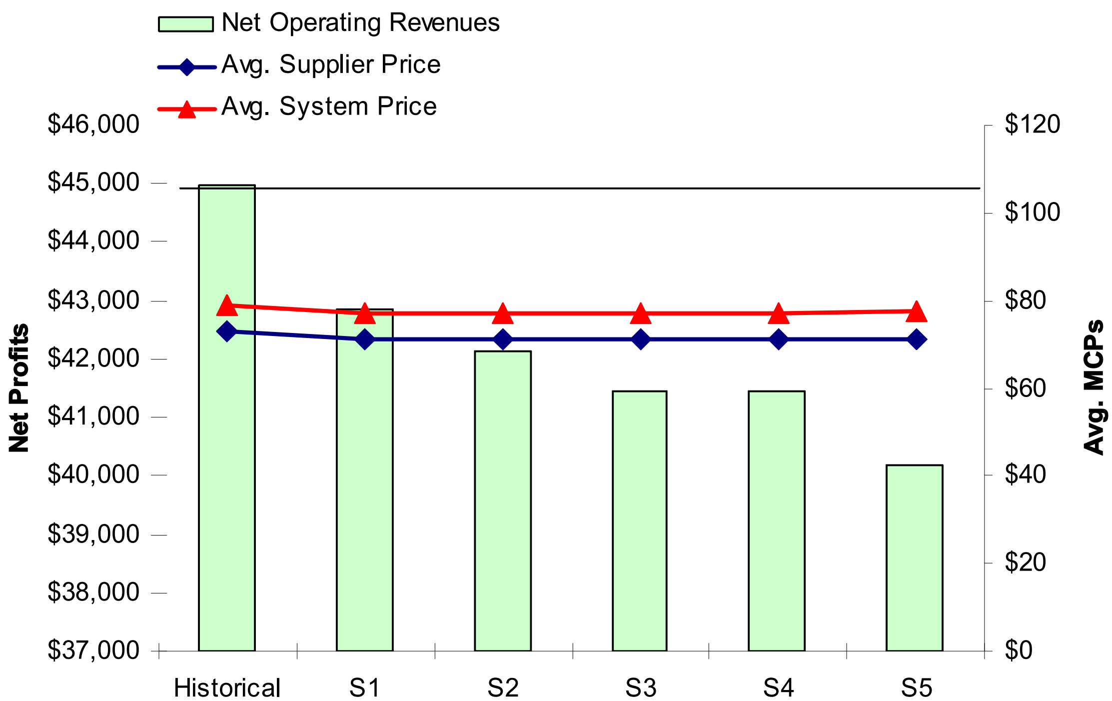
Supplier E does not benefit from withholding strategies. The capacity that is economically withheld by Supplier E is replaced by increased imports and generation from Supplier F, and no increase in price occurs. As noted in Footnote 6, based on discussions with operations engineering and transmission planning staff, it appears that, at a minimum, the PLEXOS model being used in this analysis does not incorporate voltage support requirements that would typically require multiple units within San Diego to be on-line. Under MRTU, such requirements may be met by manual dispatch of RMR units.



		Individual Supplier Bidding Scenarios ---------------------->					
		Marginal Cost	**Economic Withholding --------->**				
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**
Net Operating Revenues	**$15,686**	$13,906	$13,426	$13,426	$13,426	$13,426	$11,523
Avg. Supplier Price	$74.21	$70.11	$70.14	$70.14	$70.14	$70.14	$70.91
Avg. System Price	$79.04	$76.80	$76.80	$76.80	$76.80	$76.80	$77.19
SUPPLIER E							
Generation (MW)	776	882	845	845	845	845	670
Other Suppliers							
Supplier B	$74,374	$74,465	$74,465	$74,465	$74,465	$74,465	$74,374
Supplier F	$44,988	$37,885	$38,489	$38,489	$38,489	$38,489	$43,234
Supplier A	$20,168	$20,189	$20,189	$20,189	$20,189	$20,189	$20,168
Supplier D	$40,470	$39,134	$39,134	$39,134	$39,134	$39,134	$40,470
Supplier C	$53,156	$49,606	$49,606	$49,606	$49,606	$49,606	$52,468

San Diego – Supplier F

The results also show no potential for increased profits for Supplier F. The capacity that is economically withheld by Supplier F is replaced by increased imports and generation from Supplier E, and no increase in price occurs. As noted in Footnote 6, based on discussions with operations engineering and transmission planning staff, it appears that, at a minimum, the PLEXOS model being used in this analysis does not incorporate voltage support requirements that would typically require multiple units within San Diego to be on-line. Under MRTU, such requirements may be met by manual dispatch of RMR units.



		Individual Supplier Bidding Scenarios ----------------------->				
		Marginal Cost	Economic Withholding -------->			
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**
Net Operating Revenues	**$44,988**	$42,850	$42,130	$41,444	$41,444	$40,191
Avg. Supplier Price	$72.82	$71.24	$71.28	$71.32	$71.32	$71.31
Avg. System Price	$79.04	$77.26	$77.28	$77.32	$77.32	$77.41
Supplier Generation (MW)	2333	2482	2397	2321	2321	2183
Other Suppliers						
Supplier B	$74,374	$74,374	$74,374	$74,374	$74,374	$74,374
Supplier E	$15,686	$12,540	$13,409	$14,166	$14,166	$14,661
Supplier A	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168
Supplier D	$40,470	$40,470	$40,470	$40,470	$40,470	$40,470
Supplier C	$53,156	$53,197	$53,196	$53,195	$53,195	$53,113

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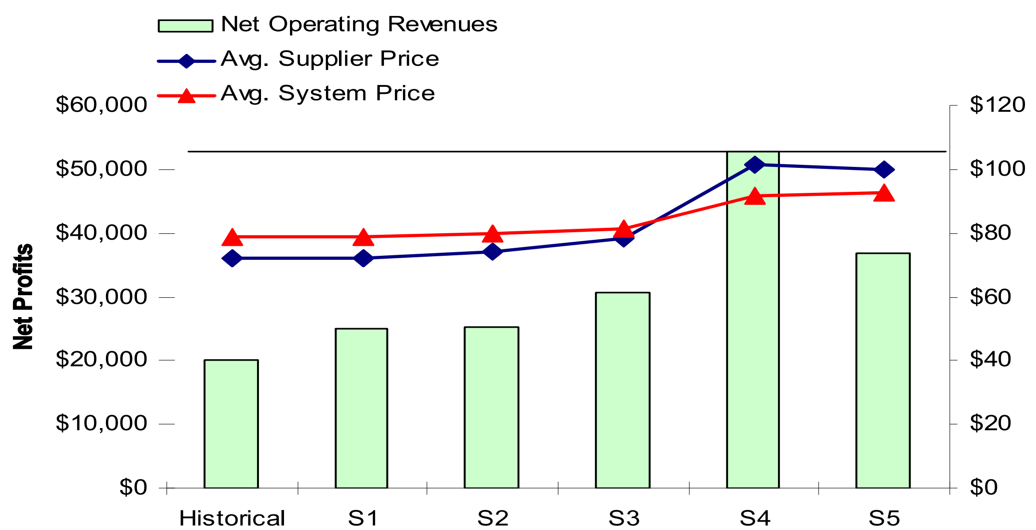
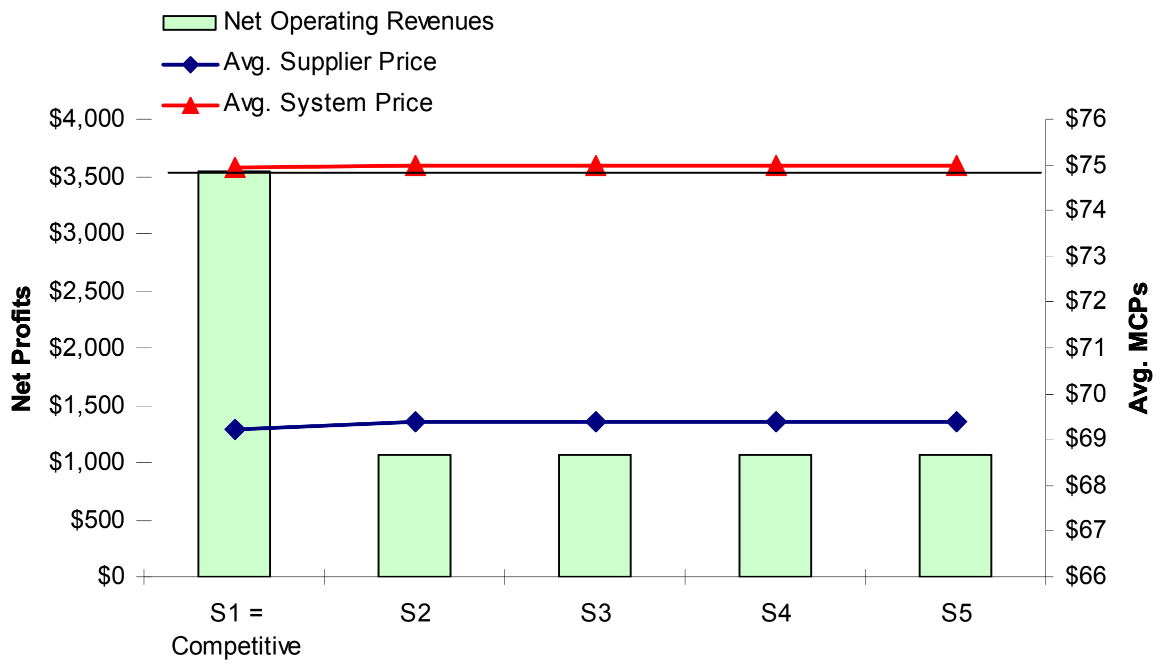
Bay Area – Supplier A

The results below show that Supplier A can significantly benefit by economic withholding. The highest profit is more than twice that of the base case. In Scenario S4, total generation from Supplier A's portfolio clearing the market is reduced to about 1,200 MWh, compared to over 1,700 MWh in the baseline scenario, which assumed all of Supplier A's units are bid at marginal costs. However, detailed examination of model results indicate that under Scenario S4 can be attributed to more general market power within a broader geographics portion of Northern California that results from a combination of economic withholding by Supplier A and relatively high bids by other suppliers in Northern California, some of which have historically bid significantly in excess of marginal costs. Although some of Supplier A and B's bids are mitigated under LMPM in Scenario S4, the high price ($102/MWh) received by Supplier A for its output is set by other suppliers' resources outside of the Bay Area with relatively high market bids. These results illustrate that while LMPM mechanisms may reduce or eliminate locational market power, these mechanisms are not designed to mitigate system level market power.



		Individual Supplier Bidding Scenarios ---------------------->				
		Marginal Cost	Economic Withholding ---------------------->			
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**
Net Operating Revenues	$20,168	$25,091	$25,109	$30,717	**$52,793**	$36,898
Avg. Supplier Price	$72	$72	$74	$78	$102	$100
Avg. System Price	$79	$79	$80	$82	$91	$93
Supplier A Generation (MW)	1,507	1,710	1,531	1,517	1,205	888
Other Suppliers						
Supplier B	$74,374	$69,721	$74,212	$77,218	$123,315	$131,830
Supplier F	$44,988	$41,452	$40,245	$39,122	$33,286	$33,943
Supplier E	$15,686	$15,580	$15,753	$16,010	$16,811	$16,487
Supplier D	$40,470	$40,230	$40,814	$41,844	$46,008	$44,875
Supplier C	$53,156	$51,369	$54,068	$55,335	$61,095	$59,504

Sensitivity analysis indicates that under the assumption of more competitive bidding by other suppliers, Supplier A's ability to increase prices and profits through economic withholding is very limited or eliminated. For example, if Supplier B is assumed to bid at marginal cost, then Supplier A cannot find a withholding strategy that increases profits, as depicted in the results below.



	Individual Supplier Bidding Scenarios ----------------------->				
	Marginal Cost	Economic Withholding ----------------------->			
Profit ($)	**S1**	**S2**	**S3**	**S4**	**S5**
Net Operating Revenues	$1,070	$1,070	$1,070	$1,070	$3,547
Avg. Supplier Price	$69.22	$69.40	$69.40	$69.40	$69.40
Avg. System Price	$74.96	$74.97	$74.97	$74.97	$74.97
Supplier A Generation (MW)	170	170	170	170	300
Other Suppliers					
Supplier B	$86,490	$86,457	$86,457	$86,457	$86,457
Supplier F	$45,662	$46,095	$46,095	$46,095	$46,095
Supplier E	$9,157	$9,101	$9,101	$9,101	$9,101
Supplier D	$17,471	$17,474	$17,474	$17,474	$17,474
Supplier C	$17,267	$17,278	$17,278	$17,278	$17,278

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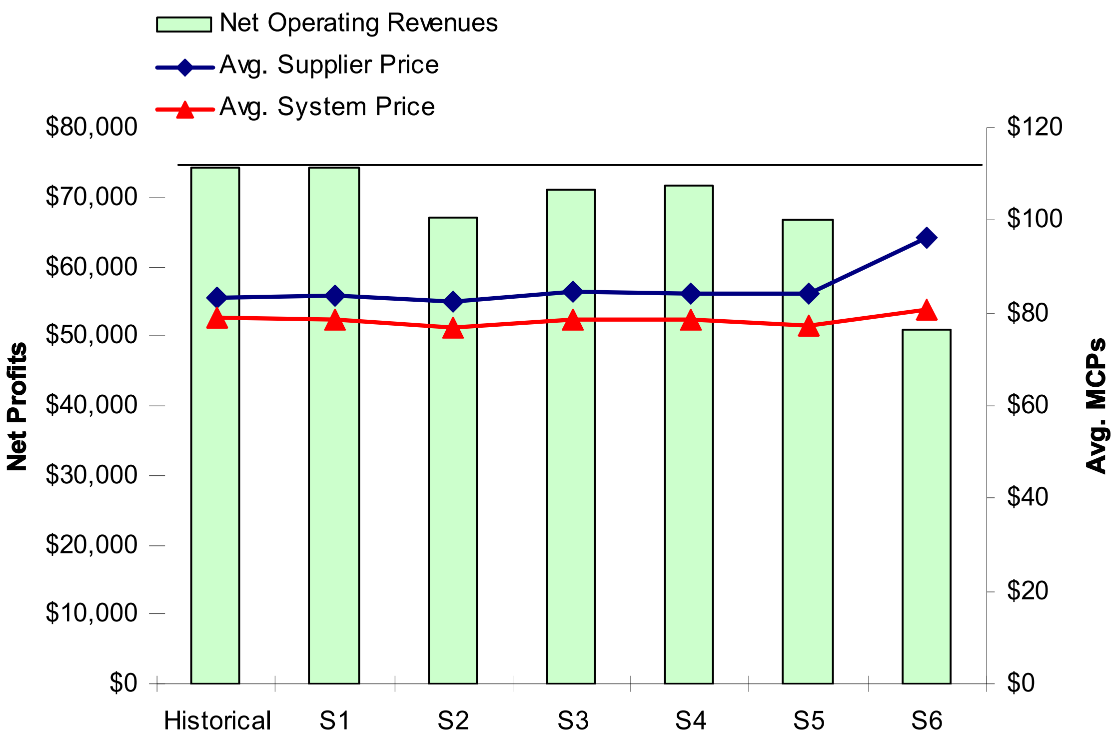
Bay Area – Supplier B

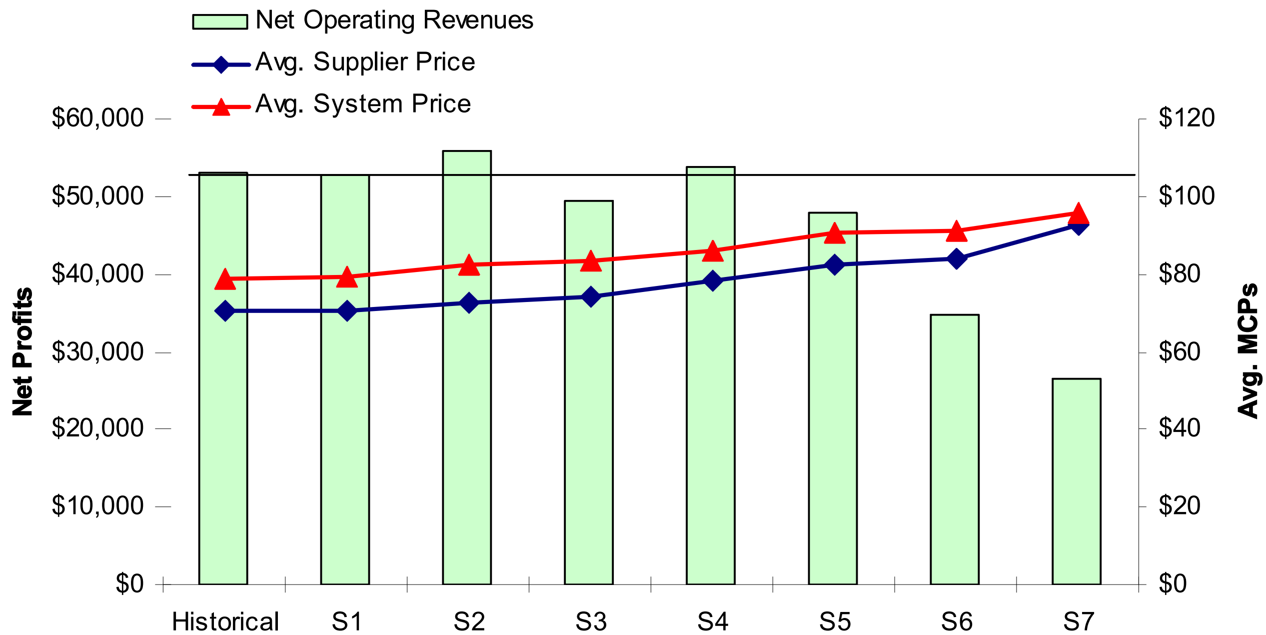
The results below show Supplier B does not benefit from unilateral economic withholding. In these cases, the LMPM mechanisms incorporated in the MRTU market design are triggered and successfully mitigate the effects of economic withholding by Supplier B. Because of mitigation, the bid price of units in the IFM is lowered to the units' DEBs, and Supplier B's overall profits decrease.



		Individual Supplier Bidding Scenarios ---------------------->					
		Marginal Cost Economic Withholding ----------------------------------->					
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**
Net Operating Revenues	**$74,374**	$74,344	$67,018	$71,132	$71,598	$66,721	$50,862
Avg. Supplier Price	$83.25	$83.61	$82.41	$84.49	$84.28	$84.37	$96.15
Avg. System Price	$79.04	$78.55	$76.64	$78.57	$78.56	$77.27	$80.70
Supplier B Generation (MW)	2357	2298	2103	2174	2203	2011	1532
Other Suppliers							
Supplier F	$44,988	$40,228	$31,738	$40,259	$40,191	$35,929	$39,888
Supplier E	$15,686	$19,705	$18,631	$19,713	$19,705	$19,077	$15,983
Supplier A	$20,168	$20,143	$24,315	$20,167	$20,168	$25,776	$38,031
Supplier D	$40,470	$40,470	$36,220	$40,499	$40,470	$38,361	$41,755
Supplier C	$53,156	$52,137	$46,292	$53,581	$53,188	$48,492	$55,182

LA Basin – Supplier C

In Supplier C's case, economic withholding has limited effect for profit incease. From S1 to S6, the withholding is not severe enough, and, in fact, Supplier C's units still set LMP in these cases. In S7, none of Supplier C's units is marginal, so the relatively higher price is set by other suppliers' units. However, Supplier C's dispatched generation becomes much less, leading to a significant decrease in profits.



		Individual Supplier Bidding Scenarios ---------------------->						
		Marginal Cost	**Economic Withholding -------->**					
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**	**S7**
Net Operating Revenues	$53,156	$52,830	**$55,932**	$49,559	$53,738	$47,872	$34,757	$26,543
Avg. Supplier Price	$70.71	$70.81	$72.82	$74.13	$78.48	$82.20	$83.83	$92.71
Avg. System Price	$79.04	$79.10	$82.48	$83.24	$85.96	$90.68	$91.26	$95.77
Supplier C Generation (MW)	3449	3326	3186	2701	2249	1762	1269	794
Other Suppliers								
Supplier B	$74,374	$74,373	$83,812	$87,009	$95,994	$110,856	$108,862	$165,117
Supplier F	$44,988	$45,186	$40,310	$42,735	$39,791	$42,350	$51,738	$60,657
Supplier E	$15,686	$15,713	$17,110	$17,951	$26,979	$33,212	$36,410	$29,267
Supplier A	$20,168	$20,168	$29,102	$29,125	$35,444	$45,456	$44,240	$44,628
Supplier D	$40,470	$40,679	$48,333	$52,887	$60,524	$69,848	$75,097	$104,020

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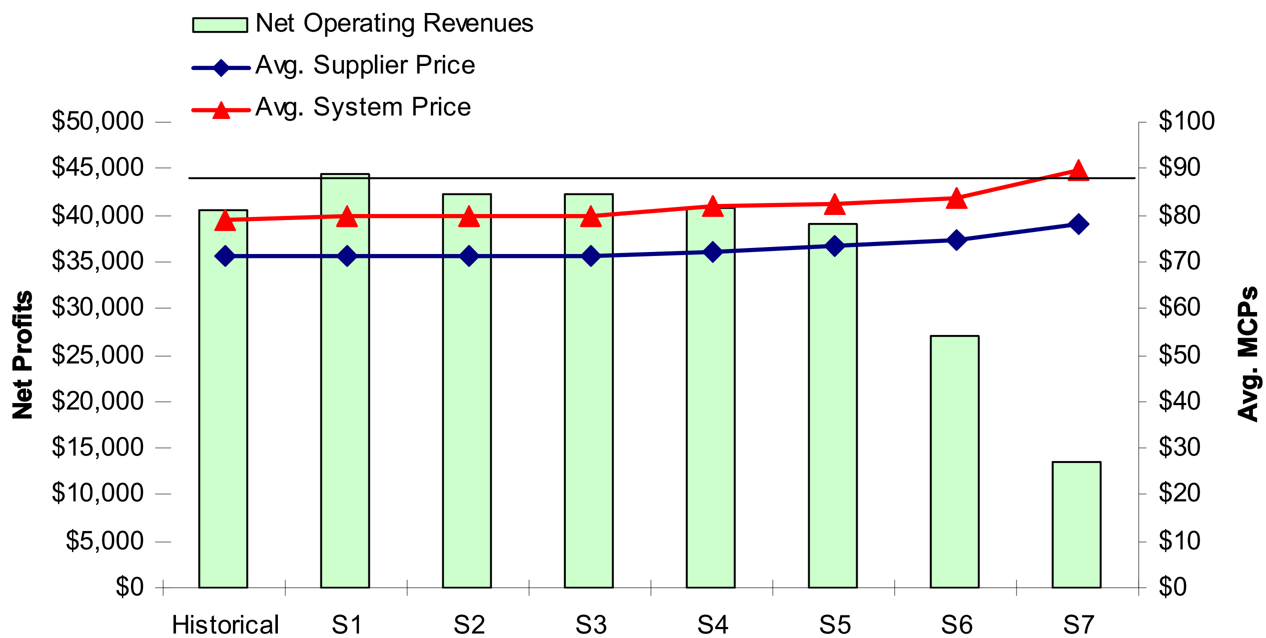
LA Basin – Supplier D

The results show no sign of increased profits from economic withholding by Supplier D. Even in the most severe withholding case (S7), there is enough competitively priced capacity from other suppliers that the price does not increase substantially, while Supplier D's profits decrease dramatically.



		Individual Supplier Bidding Scenarios ----------------------->						
		Marginal Cost	**Economic Withholding --------->**					
Profit ($)	**Historical**	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**	**S7**
Net Operating Rev	$40,470	**$44,385**	$42,208	$42,208	$40,867	$39,036	$27,106	$13,535
Avg. Supplier Price	$71.22	$71.21	$71.42	$71.42	$72.31	$73.39	$74.75	$78.20
Avg. System Price	$79.04	$79.65	$79.75	$79.75	$81.88	$82.48	$83.66	$89.73
Supplier D Generation (MW)	2243	2494	2386	2386	2171	1956	1343	640
Supplier B	$74,374	$77,936	$78,234	$78,234	$81,027	$83,888	$88,607	$108,158
Supplier F	$44,988	$38,547	$38,629	$38,629	$38,610	$40,335	$43,019	$45,982
Supplier E	$15,686	$15,651	$15,697	$15,697	$16,321	$17,076	$18,223	$21,281
Supplier A	$20,168	$22,637	$22,849	$22,849	$29,064	$29,102	$30,201	$42,154
Supplier C	$53,156	$52,654	$53,768	$53,768	$58,096	$62,352	$69,285	$84,536

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IV. Summary and Conclusions

Table 2 provides a summary of the results for each of the six major suppliers within the three areas examined in this study as presented in Section III. All data in Table 2 represent change relative to the baseline scenario that incorporates historical bid-cost mark-ups of other generators.

Table 2. Summary of Results

	Profitable to Withhold?	Decrease In Output	Generator's Price Increase	Generator's Profit Increase	System Price Increase
Bay Area Supplier A	Yes	-34%	+41%	+ 137%	+16%
Supplier B	No				
LA Basin Supplier C	Yes	-8%	+3%	+5%	+4%
Supplier D	No				
San Diego Supplier E	No				
Supplier F	No				

As discussed in Section III and summarized in the first column of Table 2, results show that under the scenarios examined in this study it would only be profitable for two suppliers to economically withhold capacity.

- Within the Bay Area, Supplier A was found to have a signficant ability to exercise market power under the scenarios examined in this study. As summarized in Table 2, economic withholding by Supplier A resulted in a 34 percent drop in output from Supplier A's portfolio, but increased the price received by Supplier A by 41 percent. The result of this witholding increased Suppliers A's profits by 137 percent and increased overall system prices by 16 percent. However, as discussed in Section III, these results can be attributed to a potential for more general market power within Northern California that results from the combination of economic withholding by Supplier A and relatively high bids by other suppliers in Northern California inside and outside of the Bay Area. In addition, as shown by the sensitivity analysis described in Section III, Supplier A's ability to increase prices and profits through economic withholding may be limited or eliminated by more competitive bidding by other suppliers. For example, if Supplier B is assumed to bid at marginal cost (rather than based on the historical bid cost mark-ups used in the base case scenarios used in this study), results show that it would not be profitable for Supplier A to economically withhold capacity.
- Within the LA Basin, Supplier C was found to have limited ability to exercise locational market power under the scenarios examined in this study. As summarized in Table 2, economic wittholding by Supplier C resulted in an 8 percent drop in output from Supplier C's portfolio, but increased the price received by Supplier C by 3 percent. The result of this witholding increased Supplier C's profits by 5 percent and increased overall system prices by 4 percent.

Overall results of this study were somewhat surprising in terms of how limited the potential for the exercise of locational market power by the type of strategic bidding identified by LECG was found to be. Thus, additional review of the reasons for these results and sensitivity analysis of different assumptions may be warranted. Potential enhancements and areas for further study are discussed in the final portion of this section.

In addition, it should be noted that while this study focused on the potential for the exercise of locational market power through the specific type of strategic bidding identified by LECG, there are other ways in which locational market power may be exercised under the current MRTU market design. These include:

- Strategic bidding to establish high DEBs for some units under the LMP-based option, and/or to allow LMPs to be set by very high DEBs that may be established for some units under the LMP-based option.
- Submission of very high startup and minimum load costs under the bid-based option for establishing startup and minimum load costs.

DMM will continue to assess these and other ways in which locational market power may be exercised under the current MRTU market design.

At the same time, results of this study do not indicate that an alternative, indirect New York-style LMPM would be more effective than the direct, PJM-style LMPM approach incorporated in the CAISO's current MRTU market design. For example, LMPM rules previously considered for the CAISO if a New York-style approach was adopted – which were based on FERC-approved rule in the New York ISO – would have allowed prices in load pockets to rise by up to the lower of $10/MWh or 20 percent due to locational market power before LMPM provisions would limit bids and prices. As discussed on the preceding page, while one scenario examined in this analysis resulted in price increases greater than this $10/MWh or 20 percent threshold, it appears that these price increases do not result from the exercise of locational market power, and instead result from more general forms of economic withholding by multiple suppliers that would not be prevented by New York-style LMPM rules.

Potential Further Analysis

The basic modeling framework established through this study can be expanded and refined to provide more comprehensive analysis of the basic issues and areas of concern identified in this study. Potential future enhancements and areas of study include the following:

- *Transmission model review.* Continued review of constraints in the PLEXOS model to ensure that the model reasonably reflects actual constraints that will be incorporated in the CAISO systems used to perform LMPM, the IFM and Security Constrained Unit Commitment (SCUC) under MRTU.
- *Review and sensitivity analysis of Local Market Power Mitigation Assumptions.* One of the key assumptions in this analysis is that all key paths that constrain supply into load pockets will be deemed uncompetitive under the CAISO Competitive Path

Assessment (CPA). In addition, the study assumes that the DEB for all units (except FMUs) will be based on marginal costs. In practice, DEBs could be significantly higher under the LMP-based option for DEBs, which is based on an average of the lowest quartile of LMPs at the unit's location during time periods when the unit is in operation. Thus, additional analysis of these key assumptions may be warranted. However, at this time, it would be very difficult to assess the level of DEBs that may result from the LMP-based option in a meaningful way due to the large number of assumptions that need to be made in such analysis. In addition, it should be noted that high LMP-based DEBs would undermine the effectiveness of both the PJM and New York-style LMPM approaches.

- *Incorporation of daily unit commitment decisions and costs*. Under MRTU, the IFM optimization will be based on bids for energy, startup and minimum load over a 24 hour period, and generators' scheduling and bidding practices will be affected by the overall profitability of different strategies over a similar 24 hour operating period. Incorporating of these daily unit commitment decisions and costs into the model would provide a more realistic assessment of the potential profitability of different biding strategies. Initial sensitivity analysis indicates that incorporating these factors into the analysis may increase the profitability of economic withholding relative to more competitive bidding strategies. DMM is currently testing the unit commitment features of the Plexos software, and developing the additional data inputs and modeling changes necessary to utilize the model to simulate the type of 24 hour optimization upon which the IFM will be based.
- *Analysis spanning a broader time period and range of system conditions*. As noted above, this analysis was based on conditions representing a relatively high load day and hour, in order to provide an indication of the ability to exercise locational market power when this would most likely be successful. However, sensitivity analysis of other system load conditions would provide a more robust assessment of this issue. Although it may not be necessary or feasible to perform extensive analysis of a full 365 day period, some methods may be developed to annualize results in order to provide a better indication of results in the context of overall market costs and prices. For instance, a sampling of different day types can be analyzed and these results can be weighted to annualize overall results.
- *Refinement of Bidding Scenarios.* The relatively simple bidding scenarios utilized in this study may be refined to identify and test other bidding strategies that may be more profitable than the basic strategy identified by LECG. For example, search methods might be developed to identify more profitable strategies within the general range examined in this study. However, unless other system conditions or model modifications are identified that would significantly alter the basic findings of this analysis, it does not appear that more refined bidding strategies would result in different conclusions.
- *Duopolistic Bidding.* As described above, the bulk of the generating resources in each of the three major load pockets in the CAISO system are owned by two major suppliers. Under such market conditions, duopolistic bidding behavior is a logical concern. Although a more general analysis of locational market power is beyond the

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scope of this study, the basic model and methodology used in this study could be applied to examine the potential for duopolistic bidding patterns.