CALIFORNIA ISO

Report on Real Time Supply Costs Above Single Price Auction Threshold: December 8, 2000 - January 31, 2001

Prepared by the Department of Market Analysis

California Independent System Operator

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EXECUTIVE SUMMARY

This report provides a preliminary cost review of real time energy bids accepted and out-of-market (OOM) purchases by the ISO to meet demand for real time Imbalance Energy during the period December 8, 2000 to January 31, 2001. The ISO has prepared this analysis and report in an effort to assist the Commission in its review and determination of the justness and reasonableness of transactions in the California electricity market since implementation of the modified single price auction market design, or *soft cap*, on December 8, 2000.

Under the soft cap approach, all bids less than a specific threshold continue to be treated under the single price auction design: any bids not exceeding this soft cap that are accepted receive a market clearing price (MCP) equal to the highest bid within the threshold accepted to meet demand. Any bids over the soft cap threshold that are needed to meet demand may be paid "as-bid", subject to cost reporting, review, and potential refund. During December 8 to 31, 2000, this threshold or soft cap was set at $250, pursuant to the ISO emergency filing on Amendment 33. Since January 1, 20001, this threshold has been set at $150 pursuant to the Commission's December 15 order.

This report compares sales of energy at prices over the $250 and $150 thresholds in the ISO's real time energy market relative to estimated costs, including what the ISO considers a reasonable margin above operating costs under current market conditions: 10% of operating costs or $25/MWh, whichever is lesser.[1] For natural gas-fired plants within the ISO Control Area owned or operated by major non-utility owners, costs are estimated based on actual unit operating levels, combined with estimated heat rates, spot market gas prices, and, where applicable, estimated NOx emission rates and emission credit costs. For imports into the ISO Control Area, costs are estimated based on daily spot market gas prices and an average 12,000 Btu/kWh heat rate (representing a relatively inefficient thermal unit), plus 10% of operating costs or $25/MWh, whichever is lesser.

The ISO's analysis presented in this report indicates that the net operating revenues earned by numerous suppliers in December 2000 and January 2001 appear to be excessive when compared to their estimated operating costs, and that the bid prices for much of the real time energy purchased by the ISO above the soft cap are likely to be deemed unjust and unreasonable once subject to a more detailed analysis of supply costs, current market conditions, and revenue earned by suppliers over the last year as a result of the uncompetitive conditions and outcomes in California's marketplace. Based on the analysis in this report, we estimate that costs for real time energy above the $250 threshold in effect from December 8-31 that may be deemed unjust and unreasonable may exceed $240 million, representing about 21% of real time energy

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[1] In its filing on Amendment 33, the ISO noted that the ISO would "particularly scrutinize any opportunity costs in excess of 10% of the production costs previously identified or $25/MWh, whichever is lesser." Amendment 33 transmittal letter, December 8, 2000, footnote 7, p.8.

costs during December 2000. If a reasonable standard for review of costs above the $150 soft cap in effect during January 2001 is applied, we estimate that real time energy costs may be at least $315 million above what may be deemed just and reasonable, representing about 63% of real time energy costs during January 2001.

The ISO has developed the analysis presented in this report in order to provide an indication of reasonableness of overall costs and the magnitude of potential refunds until more complete cost information can be obtained and fully reviewed by the ISO. We believe that results of this analysis indicate that further review of all transactions over the $250 and $150 thresholds in effect since December 8, 2000 is warranted and is consistent with the Commission's determination that all sales for resale in the California electricity markets are subject to refund as of October 2, 2000. We recognize that additional review and actual cost data that may be provided by suppliers may, in some cases, support the just and reasonableness of sales of real time energy above the $250 and $150 thresholds. At the same time, we believe review based on actual cost data from suppliers will in many cases show that actual costs were lower than assumed in this study. In any event, we believe the preliminary analysis presented in this report clearly indicates that such more detailed review is warranted under the Commission's acknowledged obligation to exercise its refund authority to provide relief to consumers and ensure just and reasonable outcomes.

Pursuant to the ISO's emergency filing for Amendment 33, the ISO's Department of Market Analysis previously directed all Scheduling Coordinators supplying at prices over the $250 breakpoint in effect from December 8-31, 2000 to submit supporting cost data to the ISO by January 31, 2001. To date, numerous suppliers have either not responded to this request, or have responded by indicating they do not believe they are subject to any cost reporting requirements under the ISO's Amendment 33 filing. In addition, data provided by many suppliers was typically insufficiently documented to allow cost information to be verified. Nevertheless, analysis of cost data submitted by numerous suppliers pursuant to Amendment 33 is highly consistent with general findings of this report, in that total self-reported costs are significantly lower than sales costs to the ISO and indicate that unjust and unreasonable profit margins continue to result due to the current non-competitive condition of California's wholesale energy market.[2]

[2] Summary results of the ISO's analysis of cost data submitted pursuant to Amendment 33 provided in a confidential Appendix C of this report.

In order to allow more detailed analysis of the reasonableness of prices being charged in the real time market, the ISO has requested cost data for all sales of real time energy over the $250 and $150 thresholds since December 8 pursuant to Section 4.5.1 of the Market Monitoring and Information Protocol (MMIP) through a general letter issued to Market Participants data February 27, 2000. Cost data being requested under the MMIP include all sales over the $250 soft cap in effect December 8-31, as well as all sales since January 1, 2000 over the $150 threshold.

1. Background

1.1. The “Soft Cap” as an Interim Mitigation Measure for Unjust and Unreasonable Prices

The Commission’s November 1 Order found that “the electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy [and Ancillary Services] under certain market conditions.”[3] The Commission’s December 15 Order reaffirmed its finding that “that unjust and unreasonable rates were charged and could continue to be charged unless remedies are implemented.[4]

Both the November 1 and December 15 Orders stressed the need to address fundamental market conditions, structure, and design features contributing to the unjust and unreasonable prices occurring in the California marketplace. However, in both of these orders, the Commission noted that cost mitigation measures were needed to protect against continued unjust and unreasonable prices until other key structural and market design remedies could be implemented. One of the key interim price mitigation measures proposed in each of these Orders to protect against the unjust and unreasonable rates being charged in California’s energy markets was a temporary $150 “soft cap” in the PX Day Ahead and ISO real time markets.[5] Under this approach, all bids less than this $150 threshold continued to be treated under the single price auction design, with bids accepted receiving the market clearing price (MCP) set by the highest bid within this threshold accepted. Any bids over the threshold, however, may be paid “as-bid”, subject to cost reporting, review and potential refund.

The “soft cap” was intended to mitigate the cost impacts of market power and other market conditions on buyers in two ways.

- **Bifurcating the single price auction and as-bid markets.** The first way that the “soft cap” is designed to mitigate unjust and unreasonable prices is by reducing the manner in which the single price auction design can magnify the cost impact of high marginal costs.[6] As noted in the November 1 Order, the Commission envisioned that under this modified single price auction design,

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[3] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121 (2000) reh’g pending (hereafter referred to as the November 1 Order), p. 5.

[4] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,294 (2000) reh’g pending (hereafter referred to as the December 15 Order), p. 34.

[5] As noted in the December 15 Order, “the use of the $150 breakpoint and as-bid market combined with other market changes that we have implemented in this order will discipline prices in California. Moreover, we fully expect the breakpoint to be superceded as result of … adoption of a permanent monitoring plan by May 1, 2001.” December 15, Order, p. 52.

[6] December 15 Order, p. 29.

"bids using this modified single price auction will continue to be disciplined by low and moderate costs suppliers bidding their marginal costs at times other than shortages to ensure that they are chosen for dispatch and can receive the clearing price." The provision allowing suppliers to bid and receive payment in excess of the threshold was adopted on the grounds that "allowing generators to receive their as-bid price should permit generators whose costs exceed $150 to participate in the market and continue to attract new supply by reflecting in prices the true cost of scarcity."[7] As noted in the December 15 order, the Commission expected this modification to the single price auction would by itself "provide substantial relief to the buyers who remain in this market." [8]

- **Subjecting bids over the threshold to review and refund.** The second way that the "soft cap" is designed to mitigate unjust and unreasonable prices is by subjecting any bids over the "soft cap" threshold to cost reporting requirements, reasonableness review and potential refund. As explained in the November 1 Order, cost data required from suppliers for all transactions above the threshold "will be used to monitoring prices on a more current basis, in order to detect potential exercises of market power or otherwise non-competitive market prices and to adjust transaction prices, if necessary, to establish just and reasonable rates."[9]

Thus, in adopting the modified single price auction, the Commission has indicated that it would rely upon competition to discipline prices, whenever possible, but would rely on reporting, monitoring and refunds to discipline sales above the soft cap threshold as needed to protect consumers from the unjust and unreasonable outcomes occurring in California's energy markets.

1.2. Implementation of the $250 "Soft Cap" Under Amendment 33

On December 8, 2000, the ISO filed Amendment No. 33 to the ISO Tariff to address bid insufficiency in its Imbalance Energy market — a circumstance that was giving rise to severe operational concerns. Among other things, Amendment No. 33 proposed to implement a "soft" cap in its Imbalance Energy market similar to that outlined by the Commission in its November 1 Order. Specifically, Amendment No. 33 proposed to establish a $250 breakpoint in the ISO's Imbalance Energy market whereby bids equal to or less than $250 would set the Market Clearing Price (MCP) in the Imbalance Energy market and bids greater than $250 would be paid as-id and could not set the MCP. As explained in the ISO filing on Amendment 33:

> To minimize uncertainty regarding the acceptability of its interim proposal, the ISO has striven to base its proposal as closely as possible on

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7 November 1 Order, p. 51.

8 December 15 Order, p. 29.

9 November 1 Order, p. 51.

> Commission policy on price mitigation measures, as expressed in the November 1 Order. The only significant difference between the ISO's interim soft cap proposal and that proposed in the November 1 Order is the use of $250, rather than $150, as the level of the soft price cap. In light of current fuel prices and the ISO's recent experience in receiving less than a thousand MW of Imbalance Energy bids at prices of $150 or less in many hours, the ISO believes that a $150 soft cap would be tantamount to procuring all Imbalance Energy on an as-bid basis.[10]

The ISO's Amendment 33 filing also requested that reporting requirements similar to those outlined in the Commission's November 1 Order be imposed on sellers bidding above $250 in the ISO's Imbalance Energy market, and requested "the Commission require that the seller provide this information to the ISO, so that the ISO can review the costs and evaluate whether to seek Commission action regarding any costs that appear to be unjust and unreasonable."[11] The Commission accepted Amendment No. 33 without modification on December 8, 2001.

Pursuant to its Amendment 33 filing, the ISO has directed all Scheduling Coordinators supplying at prices over the $250 breakpoint in effect from December 8-31, 2000 to submit supporting cost data to the ISO by January 31, 2001. To facilitate reporting and review of cost data, the ISO provided Market Participants with guidelines for reporting cost data and supporting documentation necessary to verify reported costs. Analysis of data submitted pursuant to this request is highly consistent with the analysis in this report, with both of these analyses indicating that overall supply costs are typically well below prices charged for sales of real time energy to the ISO. A summary of this analysis is provided in Appendix C of this report. However, to date numerous suppliers have either not responded to this request for information or have responded by indicating they do not believe they are subject to any cost reporting requirements under the ISO's Amendment 33 filing. In addition, data provided by suppliers was typically insufficiently documented to allow cost information to be verified. Therefore, the ISO has developed the analysis presented in this report in order to provide an indication of reasonableness of overall costs and the magnitude of potential refunds until more complete cost information is submitted and can be reviewed fully and verified by the ISO.

1.3. Implementation of the $150 "Soft Cap" Pursuant to FERC's Final December 15 Order

On December 15, 2000, the Commission issued an order confirming that the "soft cap" approach with a $150 threshold initially proposed in its November 1 Order was to be implemented on January 1, 2001, superceding the $250 soft cap that had been implemented under Amendment 33. The December 15 Order also provided some

[10] Amendment 33 transmittal letter (December 8, 2000), p. 7.

[11] Amendment 33 transmittal letter (December 8, 2000), p. 8.

additional clarification of cost data to be reported by suppliers to FERC for sales over the $150 threshold in the ISO and PX markets. In addition, the December 15 Order established a 60-day review period following submission of cost data for sales over the $150 threshold. If the Commission does not notify sellers that sales are under review at the end of this 60-day period, sales are considered final and no longer subject to refund.[12]

1.4. Overall Market Trends Since Implementation of the "Soft Cap"

The first key feature of the "soft cap" – the bifurcation of market into single price auction for low and moderate cost suppliers and an "as-bid" market for high cost suppliers – can now be assessed based on more than two months of experience. Our review indicates that the soft cap unfortunately has provided little discipline on the exercise of market power and other structural and market design factors causing unjust and unreasonable outcomes for consumers. With the "soft cap" design, the Commission anticipated that "low and moderate costs suppliers bidding their marginal costs" to receive a market clearing price (MCP) of up to $150, while "high cost suppliers [would] bid a margin above their variable costs as a needed contribution to fixed costs."[13] In practice, however, the bulk of non-utility supply has been offered at prices above the single price auction threshold, despite the fact that most of this generation would earn a reasonable contribution to fixed costs at the MCP in this market.

Figure 1 shows the daily spot market gas prices during December 2000 and January 2001. As shown in Figure 1, spot market gas prices rose gradually from about $5 to $20/MMBtu over the month of November, before spiking sharply in the first week of December to nearly $60. This spike in gas prices was a major factor underlying the overall conditions leading to implementation of the $250 "soft cap" under Amendment 33. For instance, as gas prices rose significantly above $20, the operating cost of a significant portion of thermal plants may have risen above the $250 price cap.[14] However, as shown in Figure 1, spot market gas price fell sharply starting in the second week of December, and remained below $20 for the remainder of December 2000 and January 2001.

Figure 2 shows potential NOx emission credits costs for units within the South Coast Air Quality Management District needing to buy emission credits, based on trades through a major broker of NOx emission credits. As shown in Figure 2, NOx emission prices on this market rose up to about $42/lb during the month of December, but fell to reported prices of about $18/lb in mid-January 2001.

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[12] December 15 Order, p. 31.

[13] November 1 Order, p. 51 (including footnote 87)

[14] For instance, a heat rate of 10,000 would have a fuel cost of $300/Mw if purchasing gas in the spot market a $30/MBtu.

Figure 1. Daily Spot Market Gas Prices

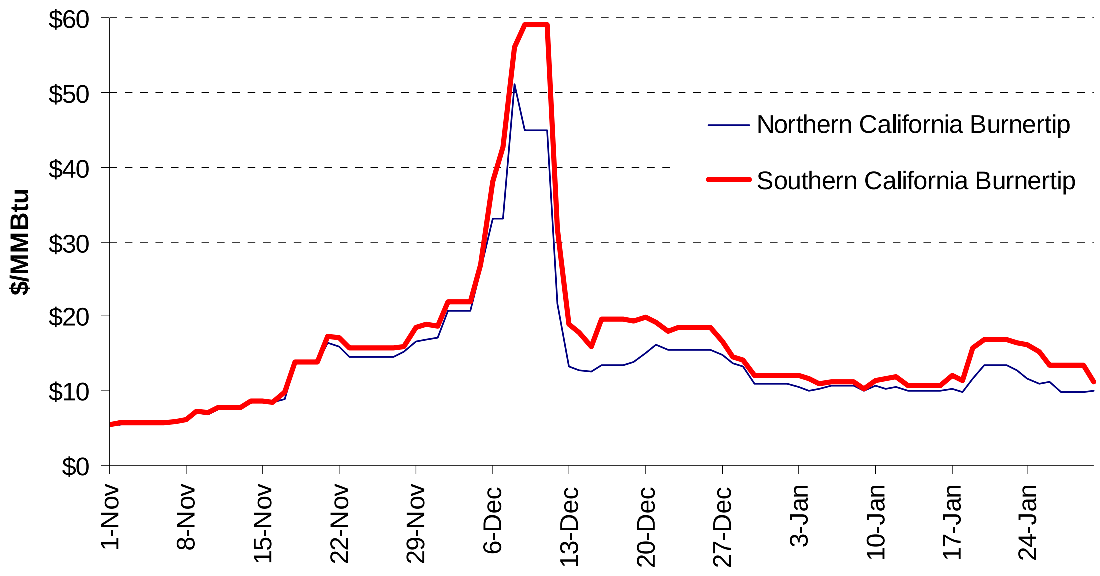


Figure 2. Potential NOx Emission Credit Costs

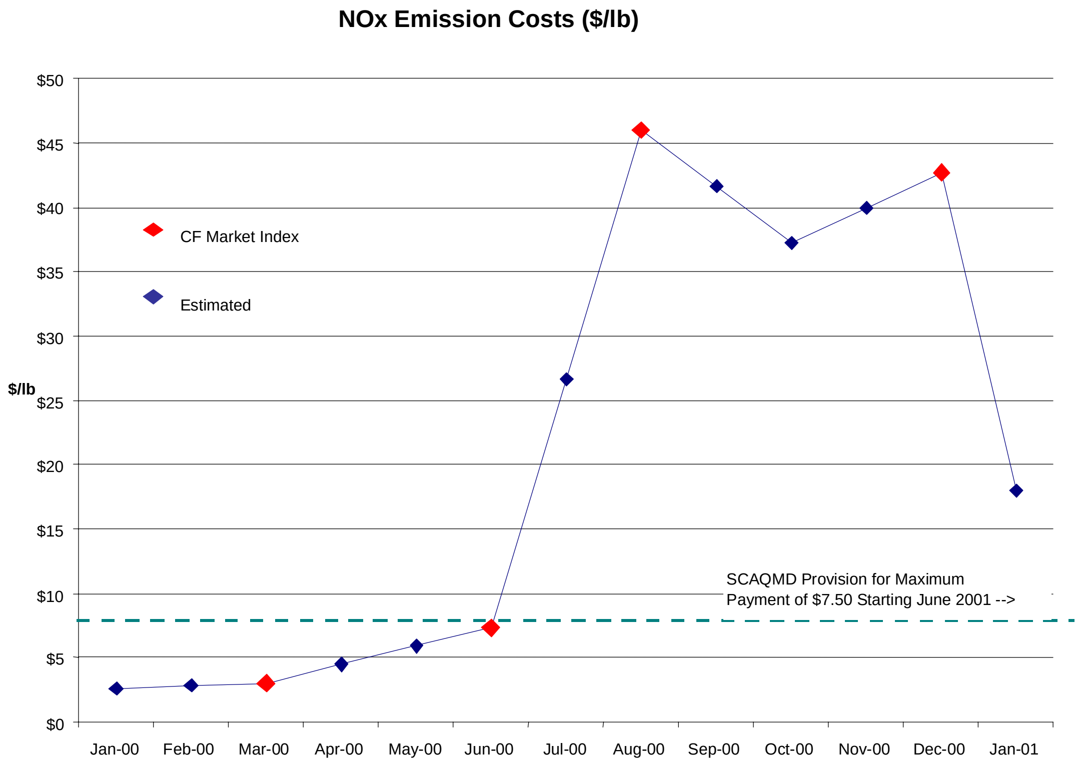


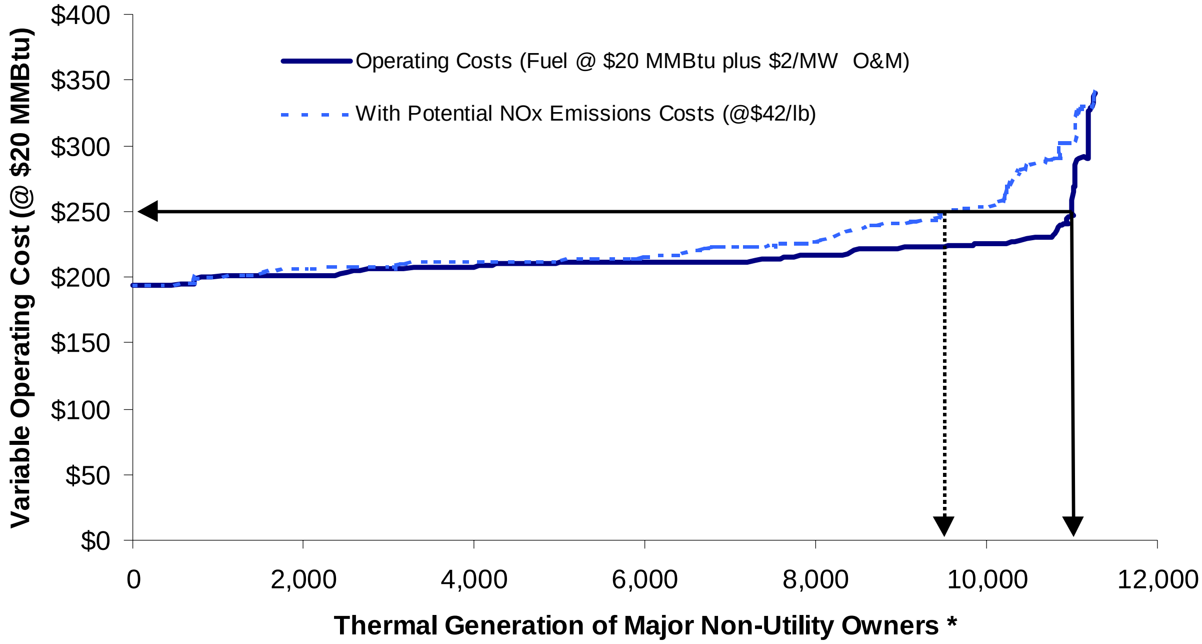
Figure 3 depicts the estimated operating costs of available thermal generation owned by the major non-utility generators in California, even with the high spot market gas and NOx emission prices that some generators may have incurred during the months of December 2000. As shown in Figure 3, even with high spot gas prices ($20/MMBtu) and NOx credit prices ($42/lb), the operating cost of most thermal capacity owned by the major non-utility owners within the ISO control system is significantly below the $250 threshold.

Figure 4 shows a similar illustration of the operating costs of available thermal generation owned by the major non-utility generators in California under typical conditions in January, when a "soft cap" of $150 was in effect. As shown in Figure 4, the operating cost of most thermal capacity owned by the major non-utility owners within the ISO control system was below the $150 threshold, even with spot gas prices ($12/MMBtu) and NOx credit prices ($18/lb).

Figure 5 summarizes the portion of total real time energy procured at prices below and above the $250 threshold in effect during December 2000 and the $150 threshold taking effect January 1, 2001. As shown in Figure 5, the bulk of real time energy procured in December was at prices above the $250 threshold, even during the last two weeks of December, when the spot market gas price fells well below $20, so that the bulk of thermal generation had an operating cost well below this threshold (as shown previously in Figure 3). Similarly, after the $150 threshold took effect in January, the bulk of real time energy was purchased at prices above this threshold, even though the bulk of thermal generation within the ISO control area would have an operating cost below this threshold as gas prices and NOx emission prices dropped in January 2001 (as shown previously in Figure 4).

Figure 3. Potential Variable Operating Costs of Major Non-Utility Owned Thermal Generation within ISO Control Area

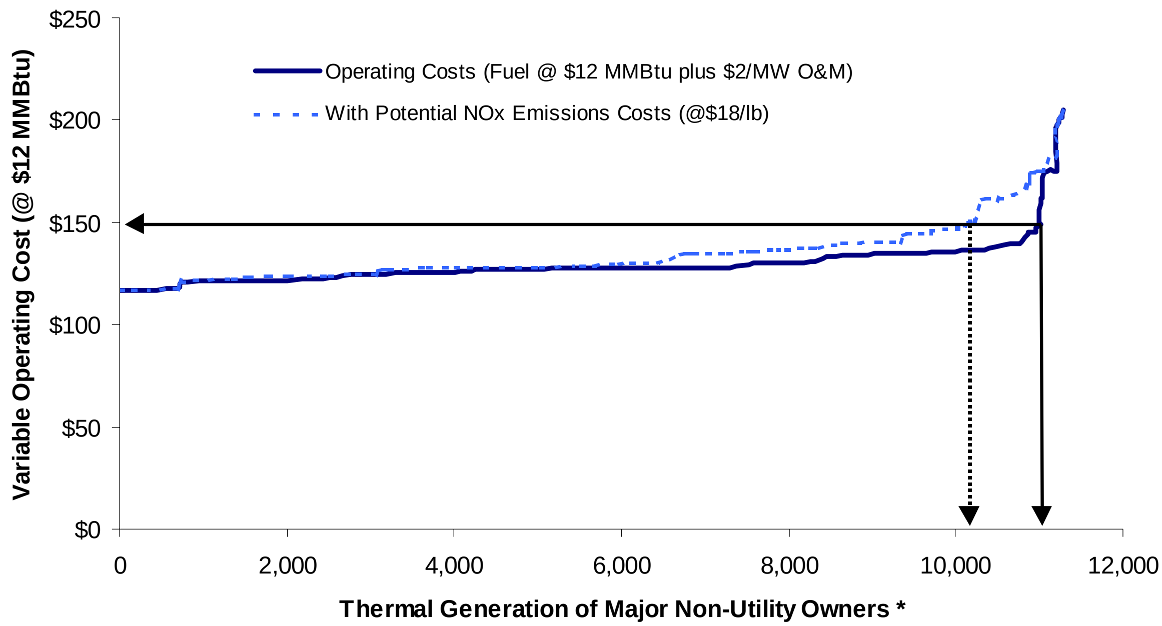
Typical Conditions - December, 2000



* Capacity adjusted based on average capacity unavailable due to outages from December 13-31 period.

Figure 4. Potential Variable Operating Costs of Major Non-Utility Owned Thermal Generation within ISO Control Area

Typical Conditions – January, 2001



* Capacity adjusted based on average capacity unavailable due to outages from January 1-31 period.

Figure 5. Portion of Real Time Energy Procured at Prices Above $250/$150 Thresholds

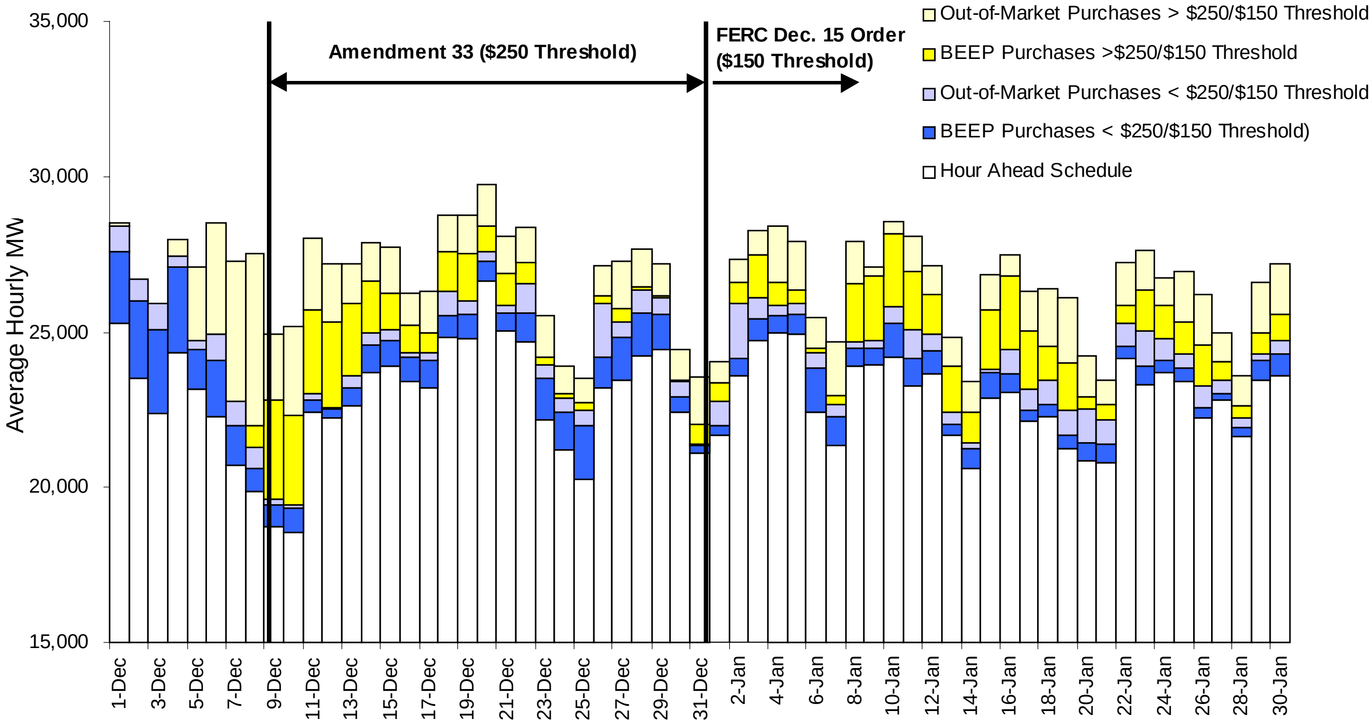


Figure 6 and 7 summarize total potential costs for real time energy at prices above and below the $250 and $150 single price auction thresholds in effect during December 8-31, 2000 and January 2001, respectively:

- As shown in Figure 6, approximately two-thirds of all real time energy procured during the December 8-31 period was procured at prices above the $250 threshold, with the total amount of potential payments in excess of the $250 threshold representing about $400 million.

- As shown in Figure 7, during January 2001, approximately two-thirds of all real time energy procured by the ISO was at prices above the $150 threshold, with the total amount of potential payments in excess of the $150 threshold representing about $350 million.

Data shown both Figures 6 and 7 include all sellers of real time energy to the ISO, including municipal utilities and other public entities, including California Department of Water Resources (CDWR), which has scheduled significant volumes of energy with the ISO as an out-of-market transaction.

Figure 6. Total Real Time Energy Procured at Prices Above $250 Threshold (December 9-31)

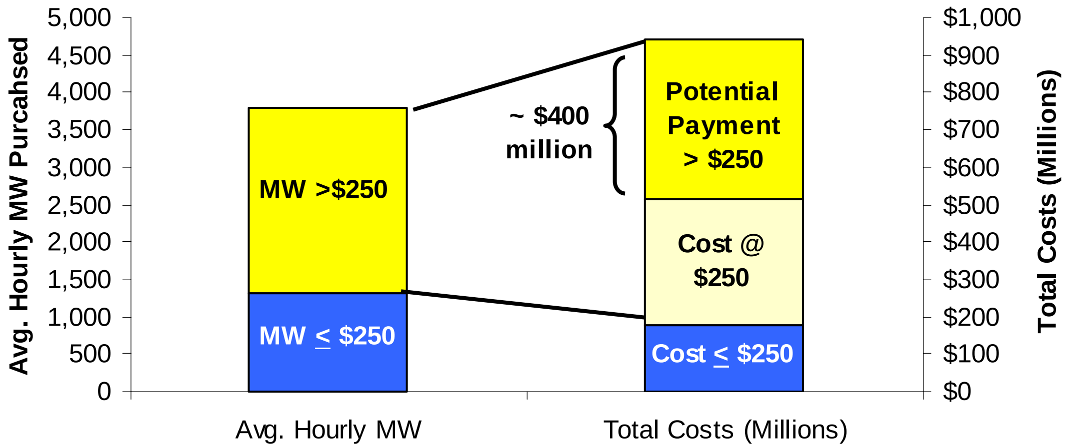
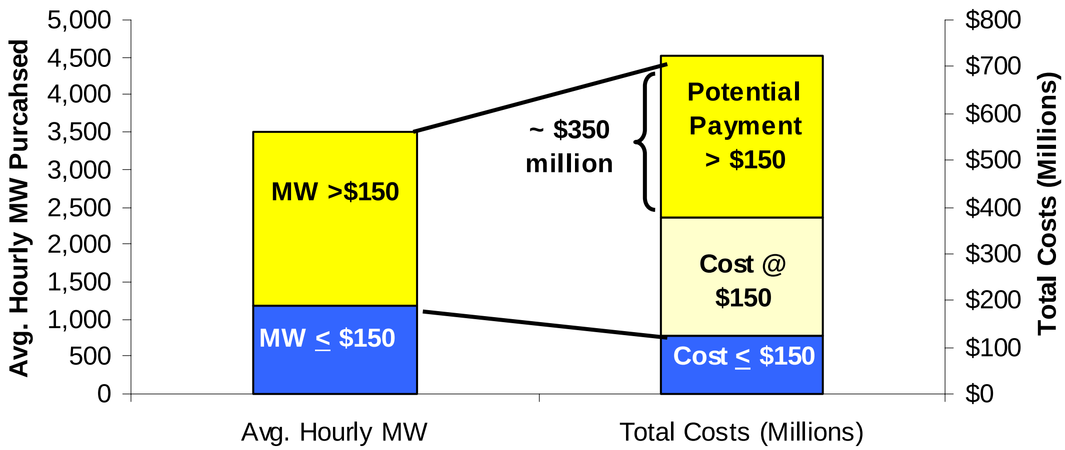


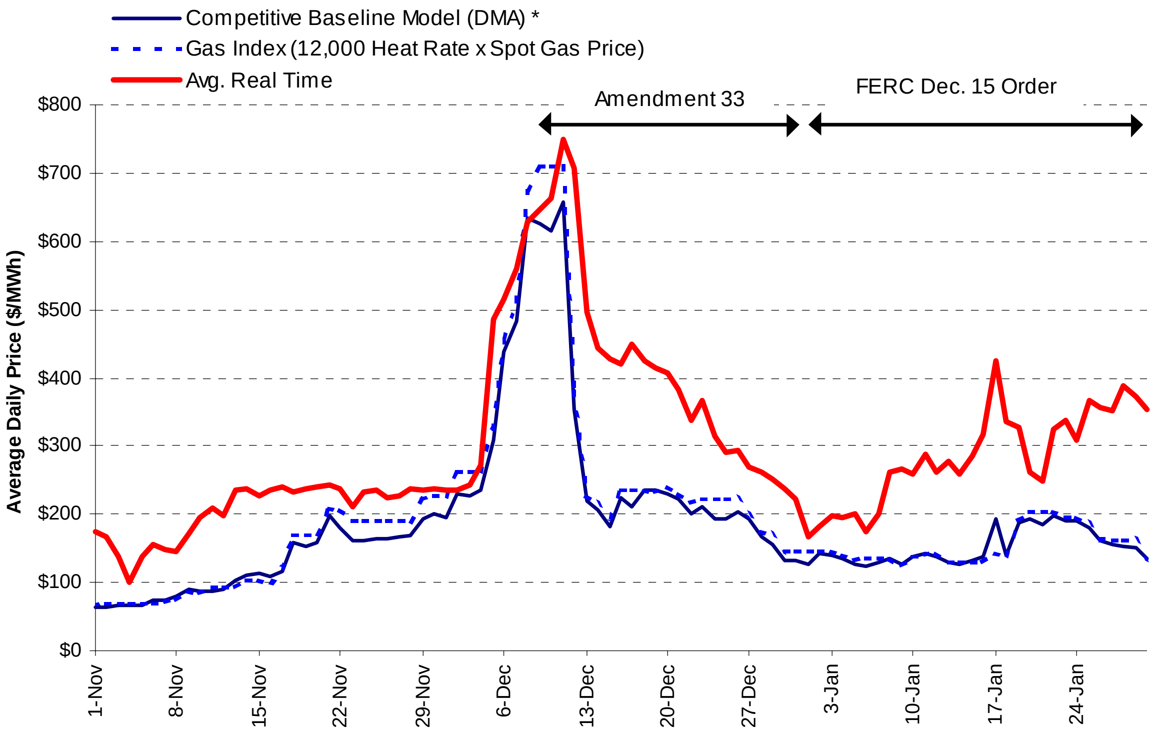
Figure 7. Total Real Time Energy Procured at Prices Above $150 Threshold January 2001 *



*** Includes energy purchased by CDWR and then scheduled with the ISO out-of-market.**

Figure 8 compares the daily weighted average price of all real time energy purchased by the ISO to a competitive baseline price calculated by the DMA, using the same basic methodology used in previous analyses submitted to FERC.[15] Real time prices are also compared to a simple price index, developed by multiplying the spot market gas price by a heat rate of 12,000 Btu/kWh. As shown in Figure 8, actual weighted average real time prices tracked relatively closely to both of cost-based baseline measures as spot gas prices spiked during the first two weeks of December. However, after this period, the average price of real time energy exceeded these competitive benchmark prices by a significant amount.

Figure 8. Comparison of Weighted Average Cost of Real Time Energy with Competitive Baseline Price and Gas Price Index



* See footnote 15 for discussion of DMA methodology for assessing a competitive baseline price.

15 This basic methodology used to calculate this competitive baseline price is described in two previous filings: Declaration of Eric Hildebrandt, in support of Proposed Offer of Settlement, filed by ISO on October 20, 2000; and Comments on FERC's November 1 Order on Proposed Remedies for California's Wholesale Markets, *Attachment A: Analysis of Market Power in California's Wholesale Energy Markets*, filed November 21, 2000. Due to the extremely high portion of imports that were purchased Out-of-Market during December, we modified this methodology to include the assumption that all real time imports actually provided had a cost equal the spot market gas price, multiplied by a heat rate of 12,000. As described in the above filings, we performed analysis of the summer and fall months by assuming that the cost of all real time energy was equal to its actual bid price.

2. Cost Review of Real Time Sales Over Single Price Auction Threshold

2.1. The ISO's Standard of Review

Beyond establishing that refunds may be used to ensure just and reasonable rates until longer-term remedies are in place, the November 1 and December 15 Orders provide limited guidance in terms of how refunds may be determined. The November 1 noted that limited refund liability to no lower than the seller's marginal cost or legitimate and verifiable opportunity cost.[16] However, the Commission December 15 Order explicitly eliminated the option of justifying as-bid prices based on opportunity costs," noting "the unworkable complexities that the opportunity cost concept introduces in the ISO real time imbalance market," and the fact that "sellers' opportunity to sell in these other markets has already passed" when transactions in the ISO's real time imbalance market occur.[17] In its filing on Amendment 33, the ISO noted that it would scrutinize particularly any opportunity costs in excess of 10% of the production costs previously identified or $25/MWh, whichever is lesser.[18]

The DMA believes that, given the structure of California's energy markets and the physical characteristics of generating resources, the "just and reasonableness" of any individual hourly bid or transaction in the real time market should ultimately be assessed in a broader context, which includes consideration of a resources overall costs and revenues in different Energy and Ancillary Service (A/S) markets over a longer period of time.

For example, during any given hour a generating resource may earn revenues from a variety of different markets, ranging from the PX Day Ahead market, bilateral transactions, A/S capacity markets, in addition to the ISO's real time Imbalance Energy Market. The overall cost and profitability of a resource depends not only on sales of real time Energy, but on sales and revenues in these other markets as well. Units providing Ancillary Service capacity, for instance, also receive a capacity payment in addition to payment for real time energy provided.

In addition, due to the physical operating constraints of many generating resources, the overall operating cost and profitability of resources must often be assessed based on an operating cycle which typically spans a period of days, rather any single individual hour. For instance, the costs of keeping a thermal steam unit on-line at minimum operating levels during off-peak hours should be balanced against operating revenues from Energy and A/S capacity sales during other hours.

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16 November 1 Order p. 56.

17 December 15 Order, p. 55.

18 Amendment 33 transmittal letter (December 8, 2000), footnote 7, p. 8.

Most importantly, DMA also believes any assessment as to whether any individual hourly transaction is "just and reasonable" requires consideration of overall market outcomes over a much longer period of time. Generators reasonably expect, over time, to recover fixed and sunk costs and earn a fair return on investment (including premiums commensurate with the risks inherent in a newly restructured market). Thus, examination of revenues earned in any individual hour may not, by itself, indicate reasonableness of prices.

However, DMA believes that the high prices the California electricity market has experienced since spring of 2000 have significantly exceeded the level necessary to ensure recovery of fixed costs (including a fair return on investment), and have exposed consumers and the broader economy to significant burden and disruption. In recent reports and filings submitted to the Commission, DMA has provided analysis showing that while a significant portion of the price increases may be attributable to an increase in production costs (e.g., fuel, emission credits, etc.) and an absolute scarcity of supply during numerous hours, a significant portion of the high market prices can clearly be attributed to the exercise of market power created by tight supply and demand conditions.[19]

Therefore, within this context, DMA believes that FERC must carefully scrutinize all sales since October 2 in terms of overall equity to consumers. A complete analysis of the extent to which recent market prices are just and reasonable is clearly beyond the scope of this study. However, consistent with the ISO's obligations to monitor the markets and identify anomalous market behavior, the ISO feels compelled at this time to screen recent sales prices against a benchmark for a what be a just and reasonable contribution to fixed costs in light of the uncompetitiveness of recent market outcomes and current market conditions, and report its preliminary findings to the Commission.

2.2. Methodology

The ISO's analysis is based on an assessment of the projected operating costs and revenues of major suppliers during the period from December 8, 2000 to January 31, 2001, including a sensitivity analysis of the refunds that might result from the Commission's ultimate determination of what costs are just and reasonable.

The ISO's analysis focuses on two major categories of suppliers: the five major non-utility owned gas-fired Generating Units within the ISO system,[20] and entities that supplied power from other control areas (i.e., imports) at prices over the $250 and $150 thresholds in effect during the period covered in this report. Together, these two

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[19] See (1) *Report on California Energy Market Issues and Performance: May-June*, 2000, prepared by the Department of Market Analysis, August 10, 2000; (2) Declaration of Eric Hildebrandt, in support of Proposed Offer of Settlement, filed by ISO on October 20, 2000; and (3) Comments on FERC's November 1 Order on Proposed Remedies for California's Wholesale Markets*, Attachment A: Analysis of Market Power in California's Wholesale Energy Markets*, filed November 21, 2000.

[20] The only major suppliers within ISO control area not included in this study are utility-owned generators.

categories accounted for over 90% of total real time Energy sales at bids over the $250 and $150 thresholds during the period covered in the study.

2.3. Operating Costs and Revenues for Thermal Units of Major Non-Utility Owners

In this analysis, generating costs for major non-utility owned gas-fired Generating Units are estimated based on the following data:

- **Heat Rates.** The heat rate of each Generating Unit is estimated based on the metered operating level of each Generating Unit during each hour, combined with the heat rate curves previously compiled by the DMA from a variety of public and proprietary sources. The heat rates compiled by DMA consist of five points, each of which represents the Generating Unit's heat rate at a specific operating level. The five points for each generating Unit's heat rate range from each unit's minimum operating level to its maximum operating level. The heat rate for each Generating Unit's metered operating level was estimated for each hour by linear interpolation between the closest two points of the five-point curve.

- **Gas Costs**. The cost of gas was estimated based on publicly reported data on daily spot market prices delivered to the Northern and Southern California borders, plus estimated distribution charges. To the extent that generators may purchase a significant portion of gas through forward market transactions, this approach may overestimate actual gas costs. Daily spot market gas prices used in this analysis are shown in Figure 1, Section 1.3.

- **NOx Emission Costs**. NOx emission rates for most units within the South Coast Air Quality Management District (SCAQMD) were estimated based on data contained in previously filed Reliability Must Run (RMR) contracts, and average emissions rates during 1999 were calculated from 1999 EPA data. Rates for units for which EPA data were not available were based on engineering estimates obtained from a variety of sources. NOx emission credits were assumed to cost $42.50/lb during December, based on trade prices obtained from brokers. To the extent that generators previously may have purchased NOx credits at a lower prices or may obtain credits at a lower price at a later date, this approach may overestimate actual emission credit costs.

The ISO recognizes that start-up costs can, in some cases, represent significant components of the cost of thermal generation. However, given current market prices and spot market gas costs used in this analysis, we believe these costs represent a relatively minor component of overall operating costs, and would not affect the fundamental conclusions of this analysis.

2.4. Cost Basis for Imports

Imports, the second category of supply considered in this study, are examined by comparing prices to a benchmark price designed to approximate the average cost of thermal generation plus a reasonable margin.

- **Benchmark Generation Cost**. The benchmark used in this analysis to screen the reasonableness of import transactions is based on daily spot market gas prices,[21] multiplied by a heat rate of 12,000 Btu/kWh. This approach is based on the assumption that the cost of either thermal (direct) or hydro (opportunity) resources during winter months should be the cost of relatively inefficient thermal generation.

- **Margin**. The benchmark used in this report to screen the reasonableness of imports also includes a potential margin above costs, equal the minimum of 10% of the benchmark generation costs described above, or $25/MWh.[22]

2.5. Operating Revenues of Suppliers

The ISO's analysis includes a *daily revenue screen*, which takes into account the estimated total daily revenues of the major non-utility owned gas-fired generating units, as described in Section 2.6. The ISO's estimate of revenues used in this *daily revenue screen* is based on the following data:

- **Hour Ahead Energy Schedules.** Revenues from Final Hour Ahead Energy schedules for each Generating Unit were estimated based on the Market Clearing Prices in the PX Day Ahead market. The ISO's analysis implicitly values any energy scheduled through bilateral contracts at the PX price.[23] The only exception to this assumption is for Reliability Must Run (RMR) Generating Units that elect to provide reliability Energy under the RMR Contract, as discussed below.
- **RMR Energy Provided Under Contract Path.** RMR Generating Units that elect to meet their minimum reliability energy requirements under the terms of the RMR Contract (i.e., they elect the *contract path)* are assumed to recover their variable operating costs (rather than market prices) for the portion of their output provided to meet these minimum reliability requirements. In effect, this

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21 Maximum of the daily spot market prices in Northern and Southern California (with estimated markup from border to burner-tip).

22 This standard is equivalent to the markup over costs specifically cited in the ISO's Amendment 33 filing as a standard that would be used to assess bids subject to scrutiny.

23 Given California's market structure, which is based on portfolio bidding in the PX and unit-level schedules submitted to the ISO, it is frequently not possible to determine if a specific unit's output was sold in the PX.

assumption ensures that net revenues from this portion of their generation are zero, since revenues from this generation is assumed to be equal to generation costs.

- **Ancillary Service Capacity.** Revenues from any Ancillary Service (A/S) capacity provided are calculated for each hour, and are included in calculations of total Generating Unit operating revenues.
- **Real Time Energy Dispatches.** Revenues from any Spinning Reserve, Non-spinning Reserve, Replacement Reserve or Supplemental Energy bids accepted by the ISO are calculated as follows: bids ≤ the $250/$150 threshold earn the MCP, while any bids over the $250/$150 threshold that are accepted are paid “as bid”. After this initial calculation, we then determine the extent to which any bids over the $250/$150 threshold exceed estimated hourly operating costs, and how the refund of any payments over $250/$150 would impact a Generating Unit’s total net operating revenues on a hourly and daily basis, as described in Section 2.4.
- **Out-of-Market (OOM) and Out-of-Sequence (OOS) Dispatches.** Revenues from any OOM or OOS calls recorded in the ISO’s OSMOSIS database are estimated based on the reported transaction price. In practice, it should be noted that analysis of scheduling and metered data indicates that a significant portion of OOM calls issued for generators within the ISO control area were subsequently met by market schedules or transactions. For instance, after receiving an OOM call on a day ahead basis, a generator subsequently may have scheduled the unit in the market and/or bid capacity from the unit into the real time market, where it would have a high likelihood of being dispatched as a market bid. In such cases, the portion of each OOM/OOS transaction that may have been met through a market Energy schedule and the remaining portion that may be settled at the OOM price is ultimately determined during the ISO’s 90-day settlement process.
- **Uninstructed Deviations.** Any uninstructed deviation is calculated based on the difference between each Generating Unit’s metered generation and its total scheduled generation level (including Hour Ahead Schedule plus any real time Energy dispatch and OOM/OOS call). Uninstructed deviations are assumed to be settled at the unit’s estimated variable operating costs.[24]

For imports, calculation of operating revenues for each Schedule Coordinator (SC) is limited to the revenues received from OOM sales and any real time Energy supplied at a price over $250/$150.

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[24] In practice, uninstructed deviations are settled at the real time imbalance price and are subject to a variety of other charges. We have valued our calculation of uninstructed deviations at the variable cost of the unit to avoid results that may be heavily influenced by errors in settlements, as well as potential errors in the actual amount of uninstructed deviations due to inaccurate metering or scheduling data.

2.6. Potential Limits on Payments Over $250

2.6.1. Thermal Units of Major Non-Utility Owners

For major non-utility-owned thermal Generating Units, the difference between the estimated operating costs and revenues of each unit represents the net operating revenues of each unit prior to any limits that may be placed on payments for real time Energy sales over $250/$150. Tables in the confidential Appendix A of this report provides a summary of the overall net operating revenues of each supplier if all transactions are settled "as-bid" and then provides a sensitivity analysis of how different price levels for sales over $250/$150 would effect each supplier's overall operating revenues, as well as total costs paid by California consumers.

The analysis then assesses the amount of potential refunds based on a variety of scenarios or criteria:

- Payment for real time Energy sales is limited to the $250/$150 threshold.
- Payment for any real time Energy sales over $250/$150 is limited to estimated direct generation costs (i.e. on an hourly basis, based on the actual operating level of the unit)
- Payment for any real time Energy sales over $250/$150 is limited to minimum of (1) estimated hourly operating costs plus 10%, or (2) estimated hourly operating costs plus $25.[25]

To address previous comments from generators that high real time prices may be justified in some hours due to lower revenues (or even operating losses) incurred during off-peak hours, we also adjust results of these scenarios based on a *daily revenue screen*, which takes into account the estimated total daily revenues of each unit, as follows:

- First, the total daily net operating revenues of each unit are calculated and are then compared to the potential limit placed on payment for real-time Energy sales over $250/$150 that is calculated based on the three decision rules described above.
- The potential reduction in payments for real-time Energy sales for each unit for each day is then limited so that a unit's daily net operating revenue would not become negative as a result of this refund, or payment reduction.

Finally, we aggregate each owner's portfolio of Generating Units in order to examine each supplier's net daily operating revenues under the range of scenarios outlined above. This reflects statements by generators that they manage and schedule resources on a portfolio basis, so that the overall profitability of the portfolio of plants therefore provides the best overall indicator of a supplier's profitability.

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[25] This standard was specifically cited in the ISO's Amendment 33 filing as a standard that would be used to assess bids subject to scrutiny.

Summary results of this analysis aggregated on a daily basis are presented and discussed in Section 3 of this report. Detailed results of this analysis on an hourly and unit-by-unit basis are provided in a confidential Appendix A.

2.6.2. Imports

For imports, which cannot be tied to specific generating resources based on data available to the ISO, potential limits on payment over the $250/$150 threshold are based on a direct comparison of the price of each hourly supply transaction to the benchmark prices (based on the generating cost of a thermal unit with a heat rate of 12,000 plus a margin of 10% or $25), as described in Section 2.2.

Summary results of this analysis aggregated on a daily basis are also presented and discussed in Section 3. Detailed results of this analysis on an hourly basis for each supplier are provided in a confidential attachment and electronic data file provided to FERC.

3. Results of Cost Analysis

3.1. Thermal Plants of Major Non-Utility Owners Within Control Area

Table 3-1 presents a summary of aggregated results for major non-utility owned thermal plants in the ISO system. Results shown in Table 3-1 are based on a scenario in which payments for real time energy bid at prices above the $250/$150 thresholds in effect during December and January are limited to variable operating costs plus a margin equal to the lesser of 10% of operating costs or $25/MW. In addition, results are based on a scenario in which any refunds were further limited based on the daily revenue screen described in Section 2.6.1.[26] Detailed results, including other scenarios and results for individual suppliers, are included in Appendix A.

As shown in Table 3-1, the average operating cost of energy provided in the real time market during this period is estimated at about $205/MW, compared to potential revenues of $354/MW if no adjustment is made to bid prices for energy called above the $250/$150 thresholds in effect during this time period. Applying refunds based on a just and reasonable standard under which payments would be limited to variable operating costs plus a margin equal to the lesser of 10% of operating costs or $25/MWh would result in refunds estimated at about $183 million dollars in the two month period examined in this study, while still allowing generators to earn an estimated margin of about $44/MWh for sales of real time energy to the ISO during this period.

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[26] As described in Section 2.6.1, this daily revenue screen assumes that refunds would be limited so that a unit's daily net operating revenue would not become negative as a result of any refund or reduction in payment for real time energy.

Table 3-1. Summary Results for Thermal Generation of Major Non-Utility Generation Owners

December 2000 and January 2001

	Real Time Sales	Gross Revenue	Variable Cost*	Net Revenue	Gross Revenue	Variable Cost*	Net Rev.	Potential Refund	Adjusted Revenue ($/MWh)	
	(GWh)	← Millions of Dollars →			← $/MWh →			(Millions)	Gross	Net
Dec 8-31	783	$315 M	$210 M	$105 M	$402	$268	$134	$ 53 M	$334	$66
Jan 1-31	952	$300 M	$145 M	$155 M	$315	$152	$163	$130 M	$178	$26
Total	1,735	$615 M	$355 M	$260 M	$354	$205	$150	$183 M	$512	$44

*Real time sales include energy bid and dispatched in the real time market (BEEP) at prices less than the $250/$150 thresholds, which earn the MCP, and energy bid and dispatched at prices above the threshold, which may be paid as-bid, subject to cost review and refund.

3.2. Imports

Table 3-2 presents a summary of aggregated results for purchases of real time energy from sources outside the ISO system during December 2000 and January 2001. Results shown in Table 3-2 are based on a scenario in which payments for real time energy bid at prices above the $250/$150 thresholds in effect during December and January are limited to the estimated cost of thermal generation (at a 12,000 heat rate x daily spot market gas prices) plus a margin equal to the lesser of 10% of operating costs or $25/MW. Detailed results including other scenarios and daily results for individual suppliers are included in Appendix B.

As shown in Table 3-2, applying a just and reasonable standard under which payments would be limited to thermal generation costs plus a margin equal to the lesser of 10% of operating costs or $25/MWh would reduce costs about $379 million dollars over the two month period examined in this study, while still allowing suppliers to earn about $245/MWh for sales of real time energy to the ISO during this period.

Table 3-2. Summary Results for Imports

December 2000 and January 2001

	Real Time Sales	Gross Revenue	Potential Refund	Average Price ($/MWh)		Gas Cost Index + 10%/$25 Margin
	(GWh)	(Millions of Dollars)	(Millions)	Unadjusted	Adjusted	
Dec 8-31	804	$463 M	$ 194 M	$576	$334	$351
Jan 1-31	900	$334 M	$185 M	$372	$166	$167
Total	1,704	$797 M	$379 M	$468	$245	$254

4. Conclusions

The ISO has developed the analysis presented in this report in order to provide an indication of reasonableness of overall costs and the magnitude of potential refunds until more complete cost information can be obtained and fully reviewed by the ISO. We believe that results of this analysis indicate that further review of all transactions over the $250 and $150 thresholds in effect since December 8, 2000 is warranted and is consistent with the Commission's determination that all sales for resale in the California electricity markets are subject to refund as of October 2, 2000. We recognize that additional review and actual cost data that may be provided by suppliers may, in some cases, support the just and reasonableness of sales of real time energy above the $250 and $150 thresholds. At the same time, we believe review based on actual cost data from suppliers will in many cases show that actual costs were lower than assumed in this study. In any event, we believe the preliminary analysis presented in this report clearly indicates that such more detailed review is warranted under the Commission's acknowledged obligation to exercise its refund authority to provide relief to consumers and ensure just and reasonable outcomes.

Pursuant to the ISO's emergency filing for Amendment 33, the ISO's Department of Market Analysis previously directed all Scheduling Coordinators supplying at prices over the $250 breakpoint in effect from December 8-31, 2000 to submit supporting cost data to the ISO by January 31, 2001. To date, numerous suppliers have either not responded to this request, or have responded by indicating they do not believe they are subject to any cost reporting requirements under the ISO's Amendment 33 filing. In addition, data provided by many suppliers was typically insufficiently documented to allow cost information to be verified. Nevertheless, analysis of cost data submitted by numerous suppliers pursuant to Amendment 33 is highly consistent with general findings of this report, in that total self-reported costs are significantly lower than sales costs to the ISO and indicate that unjust and unreasonable profit margins continue to result due to the current non-competitive condition of California's wholesale energy market. Summary results of the ISO analysis of cost data submitted pursuant to Amendment 33 provided in a confidential Appendix C of this report.

In order to allow more detailed analysis of the reasonableness of prices being charged in the real time market, the ISO has requested cost data for all sales of real time energy over the $250 and $150 thresholds since December 8 pursuant to Section 4.5.1 of the Market Monitoring and Information Protocol (MMIP) through a general letter issued to Market Participants data February 27, 2000. Cost data being requested under the MMIP include all sales over the $250 soft cap in effect December 8-31, as well as all sales since January 1, 2000 over the $150 threshold.