Appendix A

Analysis of Costs in Excess of Competitive Market Levels in California's Wholesale Energy Market (May 2000-2001)

Description of Methodology

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Summary

This appendix describes the methodology used to analyze costs incurred in California's wholesale energy market in excess of competitive levels since May 2000. The analysis builds upon previous work performed by the ISO's Department of Market Analysis (DMA), described in previous filings submitted to the Commission.[1] The analysis is based on a two step process:

- First, hourly energy prices that could be expected under competitive market conditions are estimated as a baseline for use in the analysis. Consistent with well established economic theory, the *competitive baseline price* upon which the ISO's analyses are based represent the estimated short-run marginal cost of the highest-cost thermal generating unit needed to meet system demand for capacity in a given hour.

- Second, the set of hourly *competitive baseline prices* are combined with actual hourly transactions and schedules to identify revenues earned in excess of competitive levels in each market by each seller. This stage of the analysis is being refined, as additional data on actual transaction prices and quantities in different segments of California's the wholesale market becomes available.

The main body of this report provides results of this second stage of the analysis under a variety of different *price scenarios*, representing different methods for calculating the competitive baseline price. Price scenarios examined include:

- Modeling assumptions designed to "backcast" hourly energy prices for the ISO system under the assumption that key features of the Commission's June 19 Order were in effect and successfully ensured competitive market outcomes during this period (hereafter referred to as the *FERC scenario*).

- A second scenario, in which the baseline price is calculated based on the heat rate of the least efficient gas-fired unit dispatched by the ISO in the real time imbalance market. The methodology used to calculate this price scenario is provided in Attachment B of this report.

[1] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market*, March 2001, Submitted as Attachment B to the ISO's *Comments on FERC Staff's Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market*, March 22, 2001.

Impacts of Market Power in California's Wholesale Energy Market: More Detailed Analysis Based on Individual Seller Schedules and Transaction in the ISO and PX Markets, April 9, 2001.

Methodology

Step 1: Competitive Baseline Price

The methodology used in this analysis to estimate the competitive baseline price takes into account actual hourly system load and supply conditions, and is summarized in Figure 1 and as described in detail in previous filings submitted to the Commission.[2]

The basic framework of the Commission's June 19 Order closely mirrors the underlying methodology to estimated the competitive baseline price used in previous studies submitted to the Commission by the DMA:

- The "must-bid" requirement that all available gas-fired capacity not already scheduled for energy or ancillary services must be bid into the ISO real time market is already incorporated in the DMA model. This important market power mitigation requirement is implicitly incorporated in the DMA model, since the model calculates the hourly competitive baseline price based on the full available capacity of gas-fired generation. The available capacity of each gas-fired unit for each hour based on the rating of the unit (filed with the ISO) less any capacity reported to be unavailable due to scheduled or forced outages. We note that this assumption implicate assumes that all outages are legitimate and that no capacity was *physically withheld* from the market through unnecessary or prolonged outages.

- The requirement that all non-gas-fire sources of supply be treated as *price takers* in the California market is also already incorporated in the DMA model, since the model "nets out" the actual supply of energy and operating reserves provided these sources of "residual supply" from total system demand for energy and operating reserves. Only two minor modifications (Items 6 and 7 below) were necessary to make the DMA model used in previous analyses fully consistent with this provision of the order.

The following modifications were made in the DMA model used in previous studies to reflect key provisions of the Commission's June 19 Order. As noted below, virtually all of these modifications involved the bid prices for gas-fired units under competitive market conditions:

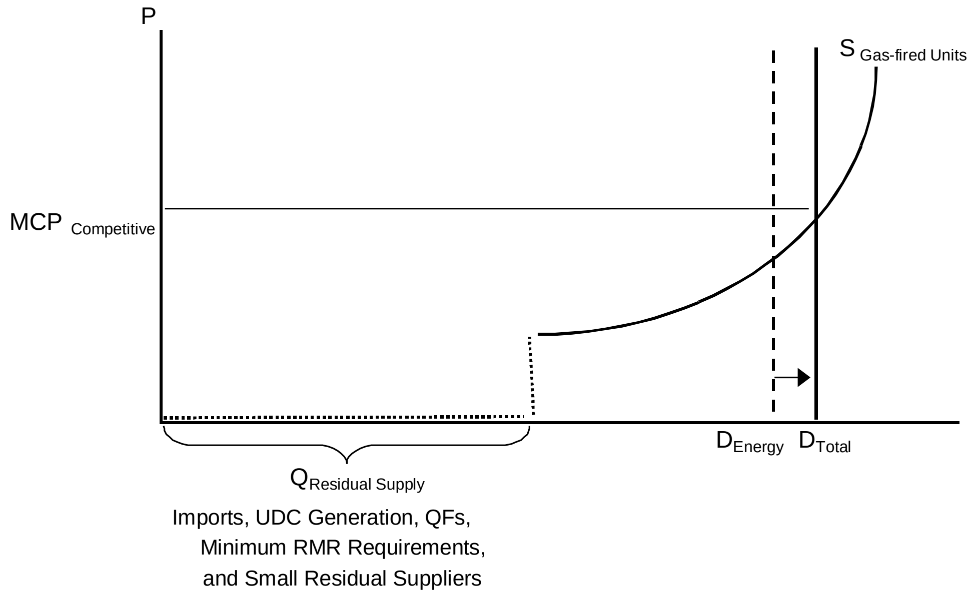
1. Incremental heat rates were based on heat rate curves filed for gas-fired units by generators pursuant to the April 26 Order. Previous DMA analyses were based on average heat rates at maximum rated capacity.
2. Gas costs were based on the average of the monthly gas contract prices for the delivery points specified in the June 19 Order. Previous DMA analyses have been done based on daily spot market prices for the Southern and Northern California borders (with units in NP15 assigned the northern CA price and units in SP15 being

[2] See footnote 1.

assigned the southern spot price).

3. Additional (non-fuel) operating costs were set at $6/MWh. Previous DMA analysis used a variable cost of $2 /MWh.
4. Potential NOx emissions costs were excluded. Previous DMA analysis incorporated potential NOx emissions costs for units in SCAQMD in order to demonstrate that this assumption explained a relatively small portion of the difference between observed market prices and prices under competitive market conditions.
5. A 10% adder was assumed (by simply increasing the final competitive baseline price by 10%), to reflect the provision for such an adder in the June 19 order.
6. For the scenario representing the June 19 Order, all gas-fired units within the ISO area are included in the supply curve used to determine the hourly competitive market price. In previous DMA studies, only the gas-fired units of the major five non-utility generation owners were included in the supply curve, with the amount of energy or operating reserves from the gas-fired units of smaller "residual suppliers" being "netted out" of demand.
7. For the FERC scenario, the DMA model was modified so that all imports are treated as *price takers*, with the actual quantity of imports being *netted out* of system demand. As previously noted, the previous DMA model included imports of replacement reserve and supplemental in the "supply curve" at their actual bid prices, rather than being netted out of demand, through November 2000. Due to the fact that virtually all imports since late November have been procured "out-of-market" (for which no bid prices are available that might be assumed to reflect marginal costs), the model was modified so that starting at that time, all imports are "netted out" of system demand.

Figure 1. Competitive Baseline Cost Methodology



The competitive market baseline price used in this report and previous ISO analyses represents the estimated variable operating cost of the highest cost thermal generation unit needed to meet system demand each hour.

To estimate this competitive baseline price, the operating cost of major non-utility owned thermal units within the CAISO system are first estimated based on incremental unit heat rates filed with the ISO pursuant to the Commission's May 26 Order, and monthly gas prices specified in the June 19 Order.

The net system demand that must be met by these resources is then calculated for each hour by first increasing total system loads by 10% to account for additional capacity needed for on-line reserves (about 3% for upward regulation and 7% for operating reserve), as shown in the figure above. The portion of this demand met by utility owned generation, scheduled imports, renewables and smaller "fringe" suppliers is then "netted out" of demand. In practice, this supply can be effectively "netted out" of system demand by including it as "must-run" supply, as shown in the figure above.

As illustrated above, the competitive baseline price represents the variable operating cost of the highest cost thermal generation unit needed to meet system demand each hour.

Step 2: Analysis of Potential Revenues in Excess of Competitive Levels

Since the focus of this study is on excess revenues earned by individual suppliers due to uncompetitively high prices in California's wholesale energy markets, the methodology and results of this study are described from the "supply side" perspective, or in terms of *excess revenues that would be received by suppliers based on hourly market schedules and prices.* Separate financial analysis is necessary to assess the potential allocation of these costs to buyers of energy and ancillary services, and degree to which these costs have not actually been paid to suppliers.

ISO Real Time Energy Market

The excess revenues above competitive levels received from real time energy dispatched through the ISO's Balancing Energy Ex-Post Price (BEEP) software was assessed based on dispatch records. Prior to December 8, all energy dispatched in the real time energy market received the real time MCP (or hourly ex-post price).

Since December 8, 2000, the real time market also includes sales above the \$250/\$150 "soft caps", which may be paid on an "as-bid" basis, but are subject to cost review and refund by FERC.

For purposes of this study, the real time market is defined as including out-of-market (OOM) purchases by the ISO, as well as any energy dispatched through the hourly imbalance market. Out-of-market purchases made by CDWR are broken out separately, and classified in terms of the seller indicated the *interchange_id* code appearing in ISO records.

The excess revenues above competitive levels in the real time market are estimated in this study by first recalculating the actual price of this energy, and then comparing it to the price of the same quantity of energy at the hourly competitive market baseline price calculated as part of the previous analysis by DMA submitted to the Commission. First, total real time energy revenues earned by each generating unit (or real time import) are calculated for each hourly dispatch by multiplying the incremental quantity dispatched by the hourly real time imbalance energy price:

$$\text{Actual Revenue}_{u,t} = \text{Dispatched MW}_{u,t} \times \text{Real Time Price}_{t}$$

For purchases made out-of-market or at prices above the "soft cap", the <u>bid price</u> of these transactions is used in place of the real time price in the equation above.

Payments in excess of competitive levels are calculated based on the difference between transaction prices and the hourly competitive baseline price:

$$\text{Excess Payments}_{u,t} = \text{Dispatched MW}_{u,t} \times \text{Max}(0, \text{Real Time Price}_t - \text{CBP}_t)$$

As noted above, this analysis only includes incremental energy purchases by the ISO. Costs for incremental energy purchased by the ISO are allocated the Schedule Co-ordinators (SCs) based on a combination of (1) unscheduled load (actual metered loads in excess of final Hour Ahead demand schedules submitted to the ISO by each SC) and (2) "under generation" (or metered generation levels lower than final generation schedules).

Analysis of how total excess charges for imbalance energy were distributed among SC's by the ISO will require more detailed analysis by the ISO's Settlements division. Until the close of the PX, the bulk of these charges were ultimately billed to the PX, which served as the SC for the state's major Utility Distribution Companies (UDCs). The PX, in turn, allocated these charges to the UDCs as well as other entities scheduling load and generation through the PX. Thus, much of the analysis of how excess payments were distributed among market participants must be performed by the PX.

The degree to which excess costs were incurred by specific suppliers within the ISO control area is captured in the analysis of uninstructed deviations included in a separate part of this analysis. With this approach, any excess costs incurred by suppliers within the ISO control area is effectively "netted off" of revenues earned from positive uninstructed deviations (or metered generation levels higher than final generation schedules).

Out-of-Market (OOM) Energy Purchases

Since May 2000, significant quantities of energy have also been procured by the ISO directly from suppliers through *out-of-market* (OOM) purchases. Due to the financial crisis that developed in early 2001, the bulk of energy purchased out-of-market since January has been purchased through CDWR, with CDWR arranging purchases with suppliers and then scheduling this energy with the ISO. Excess charges for OOM purchases are treated in the same manner as real time energy dispatched directly though the ISO's automated balancing energy market (BEEP), except that the transaction price is based directly on a reported sales price, rather than a the real time energy market clearing price.

$$\text{Actual Revenue}_{u,t} = \text{Purchased MW}_{u,t} \times \text{Purchase Price}_{u,t}$$
$$\text{Excess Payments}_{u,t} = \text{Purchased MW}_{u,t} \times \text{Max}(0, \text{Purchase Price}_t - \text{CBP}_t)$$

OOM purchases are summarized in terms two categories: purchases made directly by the ISO, and purchases made by the ISO through CDWR. Purchases made through CDWR have been tracked back to the actual supplier based on inter-tie identification codes.

The above analysis also includes the relatively small quantities of purchases made through *out-of-sequence* (OOS) purchases by the ISO. OOS dispatches represent energy bids for generating units within the ISO control area that are above the market clearing price, but are dispatched *out of sequence* due to a need for additional energy (or voltage support) from a specific unit or group of units in order to ensure the reliability of the grid. Since OOS dispatches are based on localized constraints and reliability requirements, units dispatched out-of-sequence are paid their bid price, but these dispatches are not used to set the system-wide (or zonal) market clearing price.

Ancillary Service Capacity Markets

Experience – as well as economic theory -- shows that under competitive market conditions the prices of Ancillary Service (A/S) capacity purchased directly by the ISO would be expected to be highly correlated with energy market prices, particularly during periods of high prices and market power, but should rarely exceed the price of energy. In addition, since these prices represent specific transactions in the ISO market, this study includes calculation of the degree to which the prices of Ancillary Service capacity purchased directly by the ISO have been increased by the exercise of market power in California's wholesale market.

In this study, we have assumed that in a competitive market the price of both upward and downward regulation capacity would not exceed the hourly competitive market baseline energy price used throughout this study, so that:

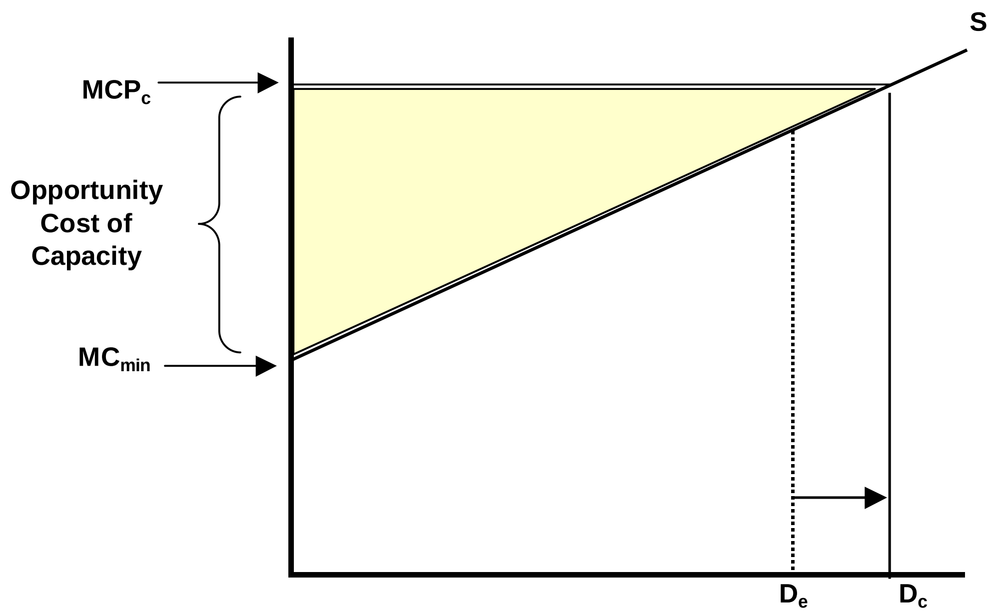
$$\text{Regulation Capacity Payment}_{u,t} = \text{Final Schedule}_{\text{i,t}} \times \text{MCP}_t$$

$$\text{Excess Capacity Payment}_{u,t} = \text{Final Schedule}_{\text{i,t}} \times \text{Max}(\,0,\ \text{MCP}_t - \text{CBP}_{\text{t}}\,)$$

This approach allows payments for regulation capacity of up to double the actual competitive baseline energy price, since units providing upward regulation also earn the real time energy price for any additional real time energy the actually provide while providing regulation.

For other Ancillary Services (spin, non-spin and replacement reserve), the competitive price of reserve capacity is based on the maximum opportunity cost of a gas-fired unit providing these ancillary services. As illustrated in Figure 2, this can be calculated for each hour based on the *difference* between the competitive market energy price and the operating cost the most efficient gas unit in the ISO system (represented by a 6,800 MBtu heat rate in this study).

Figure 2. Competitive Cost of Ancillary Services



The competitive cost of spinning, non-spinning and replacement reserve capacity was estimated based on the maximum opportunity cost of a gas-fired unit providing these ancillary services. As shown above, the difference between the competitive market energy price and the operating cost the most efficient gas unit represents the maximum opportunity costs of a gas-fired unit providing reserve capacity. In practice, units providing these ancillary services also receive an energy payment when dispatched for real time energy. In this analysis, excess revenues from sales of ancillary services were assessed based on the difference between the MCP paid for reserve capacity and the maximum opportunity cost of a thermal unit providing these reserves (i.e. rather than producing energy at the competitive MCP for energy).

Excess revenues from sales of real time energy by units providing ancillary services were assessed separately in the study, based on the difference between the real time energy MCP and the competitive baseline energy price. Thus, calculations of excess revenues allow for double payments for bot the competitive price for reserve capacity, plus an amount up to the competitive energy price for any real time energy actually provided from this reserve capacity.

Competitive capacity prices for upward and downward regulation were assumed to be equal to the competitive energy price because of the greater number of factors affecting the potential competitive cost of providing regulation. Calculations of excess revenues for regulation also allowed for double payments to generators of up to the competitive energy MCP for reserve capacity, plus an amount up to the competitive energy MCP for any real time energy actually provided from this regulation. Energy from units providing regulation is capture in the calculation of uninstructed deviations included in the analysis. Since units providing downward regulation may be required to “buy back” energy at prices higher the competitive energy MCP, any excess payments for negative uninstructed deviations during hours when the real time MCP exceeded the competitive price were also calculated and “netted off” of excess payments for any positive deviations during other hours (or other units the in generators portfolio) when the real time energy MCP exceeded the competitive level.

Thus, costs for reserve capacity (spin, non-spin and replacement) in excess of the competitive capacity prices levels CCP_t , are derived as follows:

$$\text{Reserve Capacity Payment}_{u,t} = \text{Final Schedule}_{i,t} \times MCP_t$$

$$\text{Excess Capacity Payment}_{u,t} = \text{Final Schedule}_{i,t} \times \text{Max}(0, MCP_t - CCP_t)$$

Where:

$$\text{Competitive Capacity Payment}_{,t} \ (CCP_t) = \text{Max}(0, MCP_t - (6.8 \text{ x Gas Price}))$$

In practice, units providing these ancillary services also receive an energy payment when dispatched for real time energy. In this analysis, excess revenues from sales of ancillary services were assessed based on the difference between the MCP paid for reserve capacity and the maximum opportunity cost of a thermal unit providing these reserves (i.e. rather than producing energy at the competitive MCP for energy).

Daily Spot Market Purchases by CDWR

Starting in January 2001, CDWR began procuring energy in the daily spot market and scheduling this against UDC demand in the Day Ahead and Hour Ahead load/supply schedules. [3] Data on the sales prices and quantities of these purchases were provided to the ISO for this analysis. These purchases were made for multi-hour blocks of energy (such 16 hour blocks from the peak hours 7 through 11) at a levelized (rather than hourly) price. Consequently, excess payments from these sales in excess of competitive levels were calculated on a daily (rather than hourly) basis. Specifically, the total cost of each daily block purchased was first calculated by summing up payments for all hours *t* of each day *d* :

$$\text{Total Payment}_d = \sum \ MW_{d,t} \text{ x Sales Price}_{d,t}$$

The cost of this energy at the hourly competitive baseline cost is then calculated as follows:

$$\text{Total Competitive Cost}_d = \sum \ MW_{d,t} \text{ x Competitive Baseline Price}_{d,t}$$

Any excess payments for each block of energy purchased on the daily spot market are then calculated as follows:

$$\text{Excess}_d = \text{Max}(0, \text{Total Payment}_d - \text{Competitive Baseline Cost}_d)$$

[3] In practice, under the ISO scheduling protocols, energy was transferred from suppliers through inter-Schedule Co-ordinator (or inter-SC) trades to CDWR, which in turn then transferred supply to utility demand.

Balance of Month (BOM) Purchases by CDWR

Starting in February 2001, CDWR also began procuring peak and off-peak blocks of energy on a monthly basis in Balance of Month (BOM) transactions. Like blocks of energy purchased in the daily spot market, this energy was scheduled against UDC demand in the Day Ahead and Hour Ahead load/supply schedules. Data on the sales prices and quantities of these purchases were provided to the ISO for this analysis.

Any excess payments for these purchases were calculated in the same manner as the daily spot purchases, except that excess payments were calculated on a monthly (rather than daily) basis, by comparing total purchases for each monthly BOM contract with the cost of this same monthly block of energy at the competitive baseline price.

Energy Sales in the PX Market

Final calculations of PX transactions will be performed by PX staff. However, ISO staff has developed the capability to estimate excess charges from energy sold in the PX market based on final PX schedules obtained by the ISO through the PX.

Excess revenues from sales of energy in the PX at prices in excess of competitive levels may then be calculated for each PX Market Participant (MP) as follows:

$$\text{PX Revenue}_{MP,t} = \text{PX Sales}_{MP,t} \times \text{PX\_MCP}_t$$

$$\text{Excess Revenues}_{MP,t} = \text{PX Sales}_{MP,t} \times \text{Max}(\text{PX\_MCP}_t, \text{CBP}_{t,})$$

Excess payments from purchases of energy in the PX at prices in excess of competitive levels may then be calculated as follows:

$$\text{PX Payment}_{MP,t} = \text{PX Purchases}_{MP,t} \times \text{PX\_MCP}_t$$

$$\text{Excess Payments}_{MP,t} = \text{PX Purchases}_{MP,t} \times \text{Max}(\text{PX\_MCP}_t, \text{CBP}_{t,})$$

For each market participant, the net excess revenues or payments from sales and purchases of energy in the PX at prices in excess of competitive levels may then be calculated as follows:

$$\text{Net Excess}_{MP,t} = \text{Excess Revenues}_{MP,t} - \text{Excess Payments}_{MP,t}$$

Results of this analysis provide an estimate of how excess charges in the PX market may be distributed based on excess payments incurred by different market participants.

The impact of sales/purchases in the PX Block Forward Market (BFM) was also factored in to this analysis, with results being added to (or subtracted from) totals from the PX Day Ahead and Hour Ahead markets. The net financial impact of transactions in the PX BFM can be analyzed on a monthly basis as a Contract for Difference (CFD) as follows:

$$\text{Net CFD}_{\text{BFM, MP}} = \text{Quantity}_{\text{BFM,MP}} \times (\text{Transaction Price}_{\text{BFM, MP}} - \text{Final Contract Price}_{\text{BFM, MP}})$$

Where:

$\text{Quantity}_{\text{BFM,MP}}$ = Quantity of BFM product purchased/sold by each Market Participant (MP). BFM products represent monthly contracts for peak energy in either SP15 or NP15

$\text{Transaction Price}_{\text{BFM,MP}}$ = Price that each BFM product was purchased/sold.

$\text{Final Contract Price}_{\text{BFM,MP}}$ = Final Contract Price of each BFM product, as posted on PX website. Final price represents simple average price of PX Day Ahead Market during hours of month covered by BFM product.

Results of this analysis were used to adjust the monthly net excess revenues or payments in the Day Ahead and Hour Ahead PX markets for each Market Participant as follows. If the participant's net BFM position was negative (typically indicating a payment due for sales of BFM contracts at prices lower than actual prices), any excess revenues earned by the participant in the Day Ahead and Ahead PX market during that month (M) were reduced accordingly:

$$\text{Adjusted Net Excess}_{MP,M} = \text{Max}\,(0,\ \text{Net Excess}_{MP,M} + \text{Net CFD}_{\text{BFM, MP}})$$

If the participant's net BFM payment was positive (typically indicating a credit due for <u>purchases</u> of BFM contracts at prices <u>lower</u> than actual PX market prices), any excess payments incurred by the participant in the Day Ahead and Ahead PX market that month were reduced accordingly:

$$\text{Adjusted Net Excess}_{MP,M} = \text{Min}\,(0,\ \text{Net Excess}_{MP,M} + \text{Net CFD}_{\text{BFM, MP}})$$

If the participant's net BFM payment was negative (typically indicating a payment due for <u>sales</u> of BFM contracts at prices <u>lower</u> than actual PX market prices), any excess revenues earned by the participant in the Day Ahead and Ahead PX market that month were reduced accordingly:

$$\text{Adjusted Net Excess}_{MP,M} = \text{Max}\,(0,\ \text{Net Excess}_{MP,M} + \text{Net CFD}_{\text{BFM, MP}})$$

NOTE: Prices for the PX Day-of-Market (scheduled in the Hour Ahead market) have not yet been obtained from the PX. Therefore, we have applied Day Ahead prices to these sales in this analysis.

Also, we have not yet incorporated the fact that in January, bids above the $150 "soft cap" that cleared the market would be paid "as-bid". This requires more detailed analysis of bid data. This analysis simply assumes all energy clearing the PX Day Ahead market is paid the MCP (limited at the $150 soft cap). To the extent that bids above $150 were accepted in the PX, the current analysis would <u>underestimate</u> total potential payments in excess of competitive levels.

Appendix B

Calculation of Hourly Marginal Heat Rates/Costs based on Real Time Energy Dispatches

Determination of the Heat Rate of Marginal Gas-Fired Unit

Dispatched in the Real Time Market

The assumptions used in this preliminary analysis are the following:

1. Real-time congestion is ignored.
2. Capacity that was available but not bid into the market was ignored.
3. Hourly data are used from May 2000 through August 2000. Starting in September 2000 (when the ISO implemented new 10-minute dispatch protocols), data for each 10-minute interval are available for use in the analysis. For this period, hourly values are calculated based on the weighted average of each 10-minute interval within each hour.

The process to determine the cost/heat rate of the marginal gas-fired unit for each hour/interval is as follows:

1. For each hour/ten-minute interval from the BEEP stack, determine the Acknowledged Operating Target (AOT) of each gas-fired unit for which incremental heat rates are available. From the AOT determine the unit's acknowledged operating point by summing the AOT for each service and the final Hour-Ahead schedule, if any.
2. From this operating point determine the incremental heat-rate value (BTU/kWh) for each of these units.
3. Apply the corresponding monthly gas price along with a conversion factor to determine the $/MWh marginal cost based solely on the heat-rate for each of these units.
4. Add on a $6/MWh variable operation and maintenance (O&M) cost to derive a proxy price for each unit.
5. For these units each hour, find the <u>maximum</u> proxy price/heat rate and <u>minimum</u> proxy price/heat rate for each ten-minute interval/hour.
6. Over the ten-minute interval sum the AOTs to determine the net MW acknowledged instruction.
7. If the net MW acknowledged instruction is <u>positive</u> (indicating <u>incremental</u> generation or "decreasing" of generation to balance loads and generation)) set the ten-minute cost/heat rate to the <u>maximum</u> price/heat rate as determined by step 5. If the net MW acknowledged instruction for the hour/interval is <u>negative</u> (indicating net <u>decremental</u> generation, or "decreasing" of generation to balance loads and generation) set the ten-minute cost/heat rate to the minimum price/heat rate as determined by step 5.

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8. When ten-minute data are available (After September 1, 2000), hourly values represent weighted average of 10-minute interval results. Prior to September 1, 2000, the above algorithm was modified to be run on an hourly basis, rather than for each 10-minute interval.
9. NOTE: Application of the above algorithm resulted in no values being calculated during hours when no gas-fired generation was either incremented or decremented. Missing values during these hours were filled through simple linear interpolation.

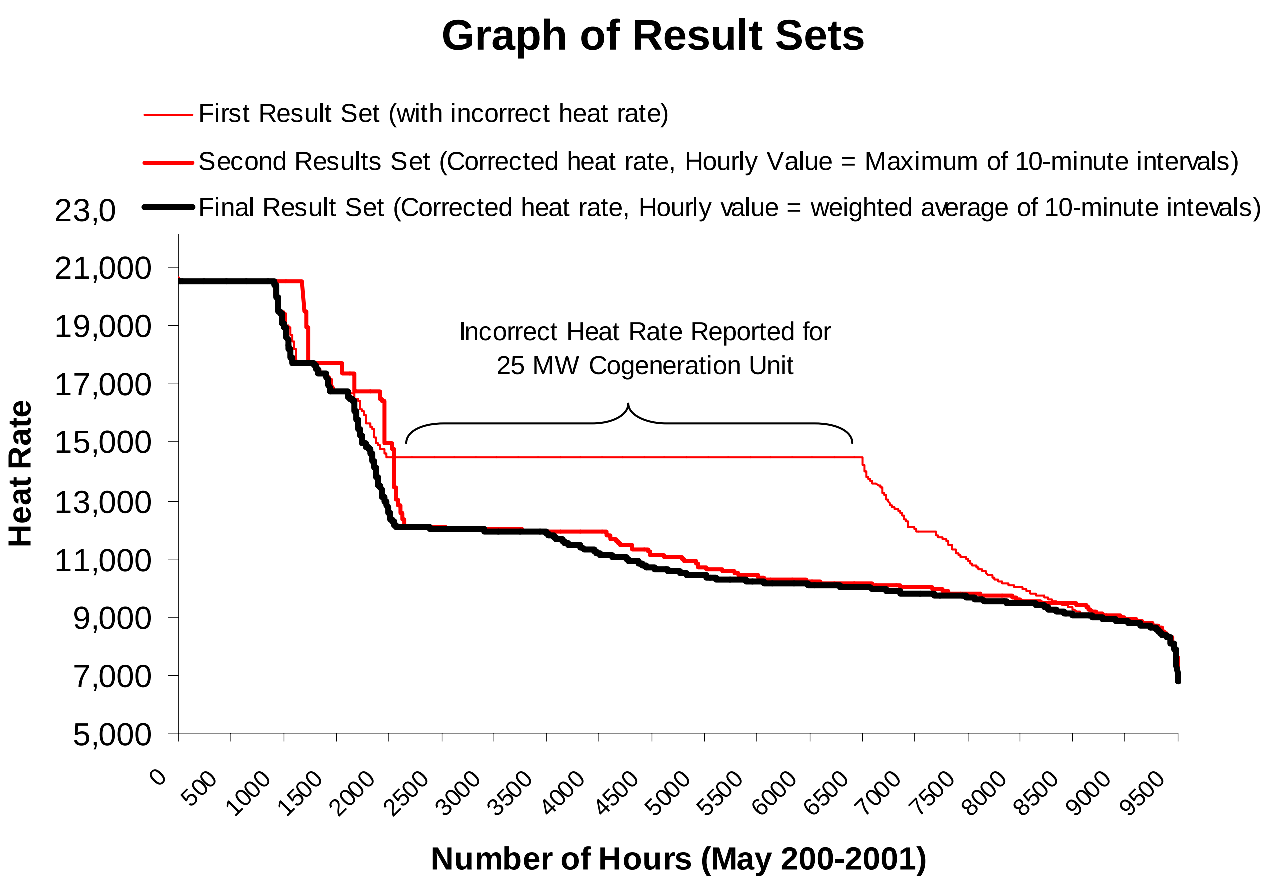
In the course of this settlement conference, two calculations were provided of the heat rate of the marginal units actually dispatched by the ISO.

The first of these files was found to contain an incorrect heat rate for a single 25 MW cogeneration unit that was identified in this initial calculation as being the marginal cost unit dispatched by the ISO in about 60% of the hours from May 200 to 2001. Further investigation and analysis of the heat rate reported by the plant operator fo this unit (14,500) indicated that this was in fact the average heat rate at minimum load, and that the heat rate declines from 14,500 to 12,000 at the higher load levels at which the unit operates when selling energy to the ISO. Thus, the actual incremental heat rate of this unit at its dispatch point of about 20 MW is 9,500, rather than 14,500. After this correct heat rate was verified with the operator and through engineering simulations, a corrected file was provided (See Figure 1).

The second set of hourly heat rates provided in this settlement conference was based on the maximum heat rate of any unit dispatched each hour (i.e. the maximum of the marginal unit during each of the 6 10-mintue intervals each hour).

A third set of calculations was also performed and used in this study after the program used to calculate the hourly marginal heat rate was refined to calculate the hourly value based on the weighted average of each the 6 10-minute intervals each hour. This refinement was added in order to more accurately calculate the marginal heat rate on an hourly basis, and because this method reflects how the real time price is actually calculated pursuant to the ISO's tariff.

The following chart compares these three result sets.



Graph of Result Sets
First Result Set (with incorrect heat rate)
Second Results Set (Corrected heat rate, Hourly Value = Maximum of 10-minute intervals)
Final Result Set (Corrected heat rate, Hourly value = weighted average of 10-minute intevals)
Incorrect Heat Rate Reported for
25 MW Cogeneration Unit
Heat Rate
23,0
21,000
19,000
17,000
15,000
13,000
11,000
9,000
7,000
5,000
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
8000
8500
9000
9500
Number of Hours (May 200-2001)