# 6. Intrazonal (Within Zone) Congestion

## 6.1 Introduction/Background

Intrazonal congestion can occur either in areas where generation is clustered together, with insufficient transmission access to allow the energy out, or where load is concentrated with insufficient transmission access to allow competitively priced energy in. In both cases, the absence of sufficient transmission access to that area means that the CAISO has to resolve the problem locally, either by incrementing generation within the area if there is not enough, or by decrementing it if there is too much. The CAISO's current method for dealing with incremental intrazonal congestion is by dispatching available RMR energy in real-time in the first instance. Should that energy be insufficient, other units are then dispatched out-of-sequence (OOS) if they have submitted real-time imbalance energy market bids, or out-of-market (OOM) if they have not. OOS dispatches are so called because they require the CAISO, when incrementing [decrementing] generation, to bypass lower [higher] priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intrazonal congestion problem. Units incremented [decremented] OOS to mitigate intrazonal congestion are paid the higher [lower] of their bid price [reference level] or the zonal market clearing price, and do not set the real-time market-clearing price. Intertie bids taken OOS are paid-as-bid.

Available thermal units within the CAISO control area are subject to the must-offer-obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids. The provisions of Amendment 50 allow the CAISO to decrement generation for intrazonal congestion using bid-reference levels supplied by an independent entity. This process is discussed in greater detail in Chapter 1.

### *6.1.1 Causes of Intrazonal Congestion*

There are numerous possible causes of intrazonal congestion. However, most of the intrazonal congestion in 2003 was either the result of adding of new generation without having adequate transmission infrastructure to meet the new transmission demands, or outages/deratings of key transmission facilities.

#### 6.1.1.1 New Generation/Inadequate Transmission

In 2003, three new generation units in northern Mexico began operation with a combined capacity of approximately 1,070 MW. These units connected to the CAISO system at the Imperial Valley substation. When combined with imported energy on the Palo Verde Intertie, which also increased due to the addition of new generation units in Arizona, they quickly overloaded the transmission system, in particular the transformer banks at the Miguel substation close to San Diego. This new congestion became evident in late July, once the last unit became operational. The CAISO foresaw this congestion problem and, in response, filed Amendment 50 in late March. Under the terms of the proposed Amendment 50, the CAISO would be provided a number of new tools with which to mitigate intrazonal congestion requiring decremental generation. Amendment 50 was approved in part. (See Chapter 1, Section 1.1.1.3 for a more detailed discussion of the filing). The resulting mitigation regime, from its July 1, 2003 implementation date, changed the way in which localized over-generation was mitigated throughout the CAISO. The principal change was the institution of bid reference levels for all control area resources.

Bid reference levels are calculated according to the protocol outlined in Section 1.1.1.3 in Chapter 1. When the CAISO needs to decrement generation to mitigate over-generation in a constrained region, it refers to the bid reference levels rather than the bid prices and units are charged the lower of their reference level or the zonal decremental market clearing price. Prior to July 1, 2003, units were charged the lower of their bid price or the market-clearing price. Since the startup of the three units in northern Mexico, congestion associated with these units has accounted for the bulk of the decremental OOS dispatches, often 80-90 percent of total dispatches. Generation from these border units, combined with energy imported at the Palo Verde intertie, have consistently overloaded the Miguel substation and have been the single most significant decremental congestion-causing event in 2003.

On occasion, the Miguel bank has been so congested that mitigation has had to include the Palo Verde-Devers and the Palo Verde-North Gila interties. Both feed energy through the Imperial Valley substation, via SWPL, and into the Miguel transformer banks. The mitigation has been accomplished by accepting supplemental energy exports OOS at the interties. By exporting out of the CAISO control area against the flow of power, the overloading of the path is mitigated. These bids are not subject to Amendment 50 provisions since they are not from control area resources. Consequently, they cannot set the MCP and are paid as bid. Prior to the startup of the border generation units, there were few supplemental energy exports accepted OOS. Since these units began operation, this has become a common method of mitigating the overloading of the Miguel banks.

#### 6.1.1.2 Outages/Deratings

Another common cause of intrazonal congestion is outages, either full or partial, of critical grid equipment. The reasons for these outages vary, from cleaning and testing to catastrophic events, such as fires. During 2003, the most well known example of this was the fire at the Vincent substation on March 18. The fire resulted in the failure of one of the three 500/230 kV step-down transformer banks. Even though a fourth transformer bank was already on order, it was not until late November that the installation and testing was complete. This caused significant congestion on the system during that period. Subsequent to the Vincent outage, there was a shorter outage at the Sylmar substation that similarly caused a significant increase in congestion while it lasted.

### *6.1.2 Operational Difficulties*

The CAISO has always preferred to resolve all congestion issues in the day or hour-ahead markets. This is the prevailing practice for resolving congestion between zones (interzonal). To the extent that intrazonal congestion can be forecast, the CAISO prefers to resolve it before real-time. Resolving forecast intrazonal congestion in real-time adds to the complexity of balancing the grid and takes from the time and attention of the grid operators, when those resources could be better utilized dealing with other unanticipated problems that occur during real-time operation. Since the emergence of persistent congestion in Southern California, Grid Operations has had to add personnel to the control room to deal with the increased real-time responsibilities.

### *6.1.3 Intrazonal Congestion Costs*

There are a number of different components of intrazonal costs.

1. Minimum Load Cost Compensation (MLCC) costs. These costs result from generating units that are committed under the provisions of the Must Offer Obligation, so that when anticipated congestion emerges, the CAISO has the resources available at the appropriate grid location to dispatch to mitigate the congestion.
2. Costs from RMR real-time dispatches that are the first response to intrazonal congestion.
3. Costs of out-of-sequence (OOS) dispatches.

#### 6.1.3.1 Minimum Load Cost Compensation

When a generator believes that it would not be profitable to run for a certain period, it is required to offer its capacity to the CAISO under the terms of the Must Offer Obligation. If the CAISO determines that the unit is not needed, the generator is allowed to shut down. Should the CAISO believe that the unit would be needed for reliability, the unit is compensated for the cost of running at minimum load. When units are kept on due to local conditions, those costs can be fairly attributed to intrazonal congestion. Table 6.1 tabulates the payments to units that were denied waivers for local reliability concerns during 2003.

**Table 6.1 2003 Must Offer Waiver Denial Costs Attributed to Local Reliability Conditions**

| Month | Days with Waiver Denial | Capacity Denied Waiver | Unloaded Capacity Denied Waiver | MLCC Payments |
|---|---|---|---|---|
| Jan-03 | 16 | 18,553 | 16,326 | 5,944,005 |
| Feb-03 | 16 | 18,553 | 16,326 | 5,944,005 |
| Mar-03 | 16 | 18,553 | 16,326 | 5,944,005 |
| Apr-03 | 12 | 14,179 | 12,263 | 3,552,598 |
| May-03 | 6 | 4,246 | 3,920 | 599,563 |
| Jun-03 | 11 | 11,095 | 10,174 | 1,946,473 |
| Jul-03 | 13 | 13,613 | 11,807 | 3,089,376 |
| Aug-03 | 28 | 63,626 | 54,209 | 12,712,017 |
| Sep-03 | 28 | 47,081 | 40,090 | 9,815,119 |
| Oct-03 | 29 | 55,697 | 47,416 | 11,324,437 |
| Nov-03 | 29 | 41,031 | 34,922 | 8,626,939 |
| Dec-03 | 29 | 41,031 | 34,922 | 8,626,939 |
| **Total** | **233** | **347,259** | **298,701** | **$78,125,479** |

For nine of the twelve months where data were available, the total cost of committing units to relieve local reliability conditions was approximately $80 million.[1] Total 2002 must offer waiver denial costs were $60.8 million, however unlike in 2003, the vast majority of these costs are likely associated with system conditions as opposed to local reliability conditions. Accurate information on the reason for must offer waiver denials are not available prior to 2003. As seen above, the capacity committed and resulting costs escalated in August and remained high through the end of the year. Approximately 99 percent of the capacity denied a Must Offer Waiver for local reliability conditions was from generating units located in Southern California.

### 6.1.3.2 Reliability Must Run Costs

To mitigate local market power, California's original (and current) market design, in the first instance, relies upon reliability must-run ("RMR") contracts with units located at known congested locations on the transmission grid. Through an annual planning process, the CAISO designates specific generating units as "RMR units," based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices. RMR units are either pre-dispatched for local reliability needs, or incremented in real-time either for local reliability or for intrazonal congestion. RMR units cannot be predispatched for intrazonal congestion.

[1] The CAISO did not track detailed information for units denied a must offer waiver during 2003. The numbers reported in Table 6.1 were derived from data collected and interpreted from operator logs that were created over a twelve-month period. Differences from month to month will reflect changes in local reliability conditions as well as changes in logging practice and interpretation of the logs after the fact. Complete data on waiver denials and subsequent payments prior to February 20, 2003, and after November 30, 2003, were not included.

### 6.1.3.2.1 Estimating Intra-Zonal RMR Costs

The payment of RMR units is complex and is dependent on the nature of the RMR contract. RMR units receive an annual fixed payment from the CAISO for various interrelated reliability needs as well as separate monthly payments for their operational or variable costs. The total fixed and variable costs are shown in Table 6.2. Total 2003 RMR costs for all the various services RMR units provide were $450 million, a substantial increase over the $373 million of 2002.

**Table 6.2 RMR Fixed and Variable Costs for 2002-2003**

| | 2002 | 2003 |
|---|---|---|
| January | $ 31,234,033 | $ 35,661,900 |
| February | $ 27,548,365 | $ (1,350,809) |
| March | $ 31,956,273 | $ 38,818,093 |
| April | $ 33,057,690 | $ 40,007,857 |
| May | $ 34,175,845 | $ 44,815,527 |
| June | $ 21,724,187 | $ 44,473,741 |
| July | $ 35,098,019 | $ 42,409,550 |
| August | $ 35,459,397 | $ 45,373,597 |
| September | $ 35,449,490 | $ 42,057,059 |
| October | $ 31,887,297 | $ 43,677,274 |
| November | $ 27,844,204 | $ 37,543,207 |
| December | $ 27,883,314 | $ 36,135,365 |
| **Totals** | **$373,320,115** | **$449,624,363** |

The complexity of determining intrazonal cost arises from the fact that predispatches for reliability needs can serve the dual purpose of decreasing grid congestion. We have adopted a conservative approach by simply ignoring this overlap on the grounds that the RMR predispatch is needed for reliability regardless of congestion needs. We count only the real-time RMR dispatches in excess of the pre-dispatch level as "intrazonal", and we measure the intrazonal cost as that cost in excess of the MCP, as the CAISO would have had to pay the MCP irrespective of energy source. Since this calculation does not include any measure of fixed cost, or any accounting for the overlap between predispatched energy and real-time energy, it is likely a conservative estimate. Table 6.3 indicates that in 2003 the RMR costs that can be attributed to intrazonal congestion, subject to the aforementioned caveats, are approximately $26.6 million. This is up substantially from the 2002 estimated RMR costs attributed to intrazonal congestion of $1.4 million.

**Table 6.3 RMR Costs for 2003**

| | MWH | | Net RMR Cost | | |
|---|---|---|---|---|---|
| 2003 | Predispatch | Realtime | Predispatch | Realtime | Total |
| January | 606,366 | 30,220 | 8,373,548 | 382,896 | 8,756,445 |
| February | 587,595 | 63,846 | 8,922,133 | 1,156,751 | 10,078,883 |
| March | 523,340 | 19,340 | 9,463,198 | 283,669 | 9,746,867 |
| April | 350,130 | 28,178 | 8,811,708 | 856,163 | 9,667,871 |
| May | 481,900 | 74,772 | 14,743,605 | 2,701,241 | 17,444,846 |
| June | 585,114 | 49,548 | 13,750,044 | 1,711,802 | 15,461,846 |
| July | 638,394 | 73,370 | 9,920,983 | 1,610,059 | 11,531,041 |
| August | 747,586 | 155,549 | 12,961,343 | 3,794,650 | 16,755,993 |
| September | 751,042 | 181,211 | 11,409,590 | 3,304,087 | 14,713,678 |
| October | 788,306 | 185,850 | 22,116,868 | 5,547,781 | 27,664,649 |
| November | 593,329 | 91,167 | 8,863,498 | 1,834,803 | 10,698,302 |
| December | 537,294 | 104,270 | 14,725,485 | 3,416,607 | 18,142,092 |
| **Total** | **7,190,395** | **1,057,322** | **$144,062,004** | **$26,600,509** | **$170,662,513** |

### *6.1.4 Out-Of-Sequence (OOS) Costs*[2]

There are a number of different ways to measure the cost of OOS calls due to intrazonal congestion. The simplest is to subtract the market-clearing price from the actual price paid and multiply the result by the MWh produced. This measure, termed "Re-dispatch Cost" is both a broad and simple measure. Should further analysis be required, the calculations of cost become more complex as they must be changed to fit specific generator and grid characteristics.

#### 6.1.4.1 Incremental Out-Of-Sequence Dispatches

Gross payments for incremental OOS energy dispatches during 2003 totaled $49 million. The net cost to load of these dispatches (defined as the premium paid over the market-clearing price multiplied by the quantity procured) was $25 million, up from $2.9 million in 2002. In all, the CAISO procured 785,325 MWh of energy at an average price of $62.60/MWh. The pattern of incremental energy dispatches was the result of three noticeable events:

1. There was a sizeable increase in incremental dispatches during March and April 2003. This was related to the fire at the Vincent substation on March 18, 2003;
2. Summer congestion began in August and continued for the next three months, declining by November. Summer congestion consists of a number of different congestion patterns, including south of Lugo congestion and Sylmar congestion (the latter caused by a lack of loaded generation in the Edison service territory); and

[2] Intrazonal congestion has traditionally been resolved by Out-Of-Sequence calls. However, due to the absence of an obligation to insert decremental bids, as well as the workings of the Amendment 50 reference levels, some of these dispatches are tagged Out-Of-Market (OOM). Whether the dispatches are OOS or OOM, the salient feature is that they are all for intrazonal congestion. Within this document any references to OOS calls will always include some OOM calls where those OOM calls are for intrazonal congestion.

3. There was a significant increase in intrazonal congestion in December. This was related to a three-week maintenance outage at the Sylmar substation.

These figures are shown in Table 6.4.

**Table 6.4 Incremental Congestion Costs 2003**

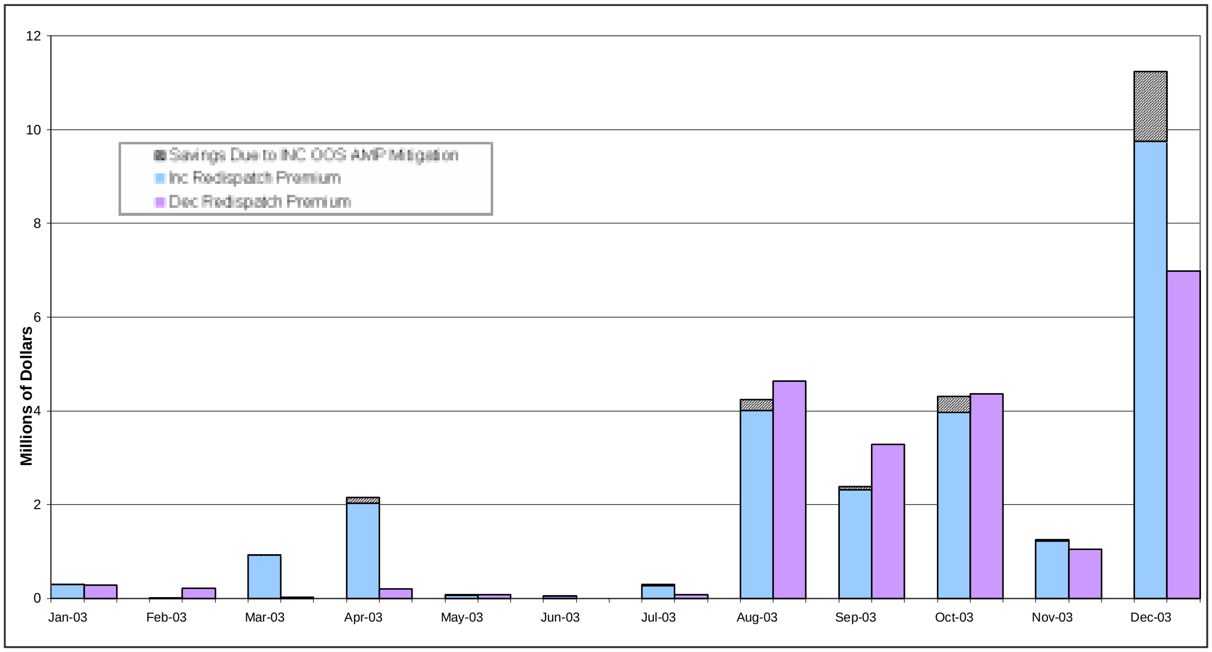
| Month | MWh | Gross_Cost | Redispatch Premium | Mitigation Savings | Avg_price | Avg Premium |
|---|---|---|---|---|---|---|
| Jan-03 | 10,452 | 724,394 | 291,557 | 7,434 | 69.31 | 27.90 |
| Feb-03 | 203 | 16,232 | 3,024 | 0 | 80.02 | 14.91 |
| Mar-03 | 33,908 | 2,565,207 | 923,153 | 2,173 | 75.65 | 27.23 |
| Apr-03 | 55,144 | 3,382,071 | 2,032,630 | 122,294 | 61.33 | 36.86 |
| May-03 | 5,384 | 365,282 | 70,827 | 9,512 | 67.84 | 13.15 |
| Jun-03 | 3,833 | 235,459 | 52,724 | 4,152 | 61.43 | 13.75 |
| Jul-03 | 10,290 | 701,738 | 268,170 | 30,284 | 68.19 | 26.06 |
| Aug-03 | 148,569 | 8,621,319 | 4,012,655 | 228,427 | 58.03 | 27.01 |
| Sep-03 | 95,822 | 5,653,539 | 2,314,004 | 75,980 | 59.00 | 24.15 |
| Oct-03 | 122,789 | 7,222,079 | 3,968,998 | 333,843 | 58.82 | 32.32 |
| Nov-03 | 47,664 | 2,595,251 | 1,224,977 | 24,887 | 54.45 | 25.70 |
| Dec-03 | 251,485 | 17,089,901 | 9,749,537 | 1,496,712 | 67.96 | 38.77 |
| Totals | **785,542** | **$49,172,474** | **$24,912,255** | **$2,335,697** | $62.60 | $31.71 |

### 6.1.4.1.1 Mitigation of Incremental OOS calls

Current local market power mitigation measures include an automatic mitigation procedure that allows for the mitigation of incremental OOS dispatches that breach a defined bidding threshold. If the OOS bid price is $50/MWh or 200 percent greater than the MCP, the bid price is mitigated to the higher of MCP or the unit's reference price. Since inception, the mitigation of incremental OOS dispatches have occurred every month with the exception of February as indicated in Figure 6.1. Rules that provided for the mitigation of decremental bids began on July 1, 2003 under the Amendment 50 guidelines detailed above. Prior to July 1, 2003, decremental bids were simply subject to a soft price cap of -$30/MWh.

The local AMP mitigation measure had a minimal impact on intrazonal congestion costs in 2003. In 2003, redispatch costs were $2,335,697 lower due to the local AMP mitigation procedure as shown in Figure 6.3. This is 9.4% of the incremental redispatch costs and 4.8% of gross incremental costs. Had the OOS calls been mitigated down to Market Clearing Prices then the entire redispatch costs would not have been incurred and the gross incremental OOS costs would have been about $25 million instead of around $49 million, as shown in Table 6.4 above and Figure 6.1.

**Figure 6.1 2003 Incremental and Decremental Redispatch Premium and Reduced Costs from Local AMP**




### 6.1.4.2 Decremental Energy Dispatches

Gross charges for decremental energy dispatches in 2003 totaled -$9,427,119 (i.e. a payment of that amount to the CAISO). The net cost to load of these dispatches (defined as the premium paid over the market-clearing price multiplied by the quantity procured) was $21.2 million, up from $1.4 million in 2002. These figures are shown by month in Table 6.5 and the decremental redispatch premium presented graphically in Figure 6.1 above.

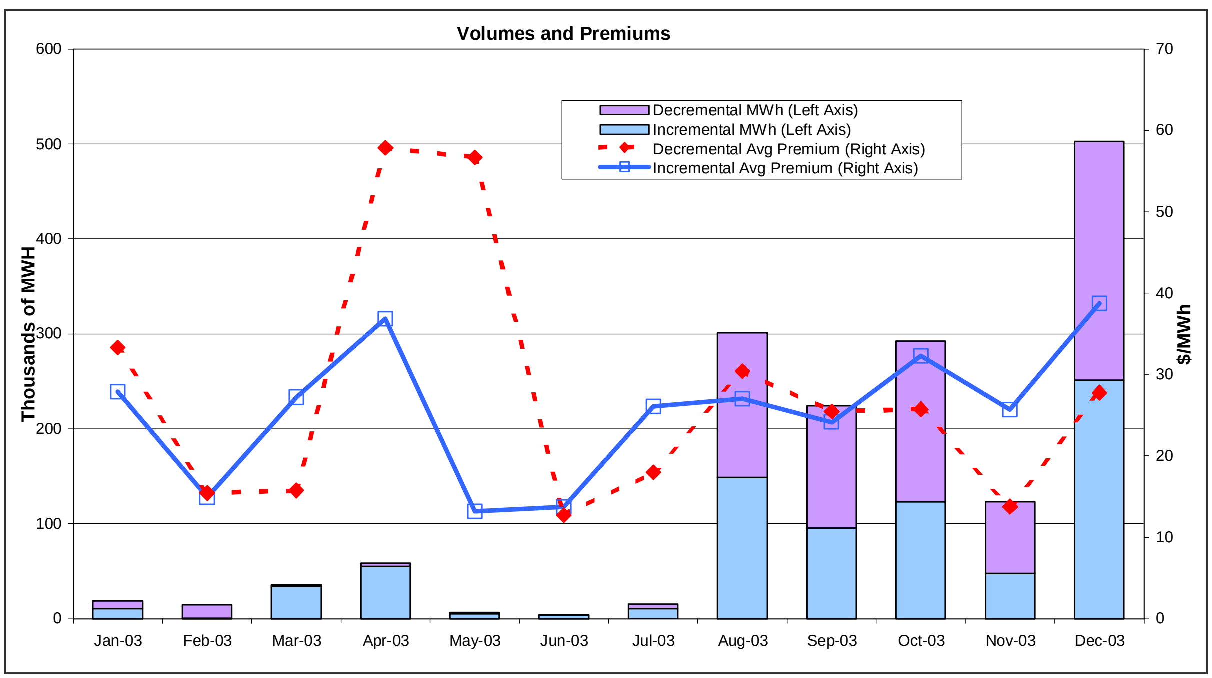
1. The sizeable increase in decremental intrazonal costs starting in August 2003 was due to the congestion on the Miguel transformer bank mentioned earlier. Congestion on the Miguel bank was mitigated by decrementing the border generation units and then by awarding supplemental energy exports at the Palo Verde tie point.
2. The sudden increase in intrazonal costs to $6 million in December was due to the Sylmar bank outage. The CAISO awarded supplemental energy exports OOS at the Sylmar NOB tie point.

## Table 6.5 Decremental OOS Congestion Costs 2003

| | DECREMENTAL | | | | |
|---|---|---|---|---|---|
| Month | MWh | Gross_Cost | Redispatch | Avg_price | Avg Premium |
| January | 8,399 | -201,316 | 279,790 | 23.97 | 33.31 |
| February | 14,347 | -481,339 | 221,512 | 33.55 | 15.44 |
| March | 1,933 | -66,497 | 30,418 | 34.40 | 15.74 |
| April | 3,478 | -56,352 | 201,277 | 16.20 | 57.87 |
| May | 1,319 | -3,701 | 74,825 | 2.81 | 56.72 |
| June | 6 | -106 | 72 | 18.83 | 12.73 |
| July | 4,589 | -86,337 | 82,541 | 18.81 | 17.99 |
| August | 152,407 | -1,357,575 | 4,633,960 | 8.91 | 30.41 |
| September | 128,836 | -1,851,642 | 3,284,141 | 14.37 | 25.49 |
| October | 169,379 | -1,480,052 | 4,360,797 | 8.74 | 25.75 |
| November | 75,785 | -1,591,488 | 1,043,206 | 21.00 | 13.77 |
| December | 251,507 | -2,250,714 | 6,983,667 | 8.95 | 27.77 |
| **Totals** | **811,987** | **-$9,427,119** | **$21,196,205** | **$11.61** | **$26.10** |

Figure 6.2 below graphically presents much the same information as shown in Tables 6.4 and 6.5 above. The figure shows the split between the incremental and decremental MWh dispatches as well as the respective premiums for each. A sizeable increase in dispatches is evident in August, due primarily to the emergence of the border generation/Miguel Bank congestion on the decremental side, and the summer congestion patterns made worse by outages of the Vincent and Sylmar substations.

### Figure 6.2 2003 Out-of-Sequence Volumes and Redispatch Premiums



### *6.1.5 Total OOS Redispatch Costs*

In all, the CAISO dispatched 1.6 million MWh for intrazonal congestion for a combined redispatch cost of $46.1 million and an average redispatch premium of $28.86/MWh. These combined figures are shown in Table 6.6.

**Table 6.6 Total OOS Intrazonal Redispatch Costs**

| Month | MWH | Re-dispatch Premium | Average Re-Dispatch Premium |
|---|---|---|---|
| Jan-03 | 18,851 | 571,346 | 30.31 |
| Feb-03 | 14,550 | 224,536 | 15.43 |
| Mar-03 | 35,841 | 953,571 | 26.61 |
| Apr-03 | 58,622 | 2,233,907 | 38.11 |
| May-03 | 6,704 | 145,652 | 21.73 |
| Jun-03 | 3,839 | 52,796 | 13.75 |
| Jul-03 | 14,879 | 350,711 | 23.57 |
| Aug-03 | 300,976 | 8,646,615 | 28.73 |
| Sep-03 | 224,658 | 5,598,145 | 24.92 |
| Oct-03 | 292,168 | 8,329,794 | 28.51 |
| Nov-03 | 123,449 | 2,268,184 | 18.37 |
| Dec-03 | 502,991 | 16,733,204 | 33.27 |
| **Totals** | **1,597,528** | **$46,108,461** | **$28.86** |

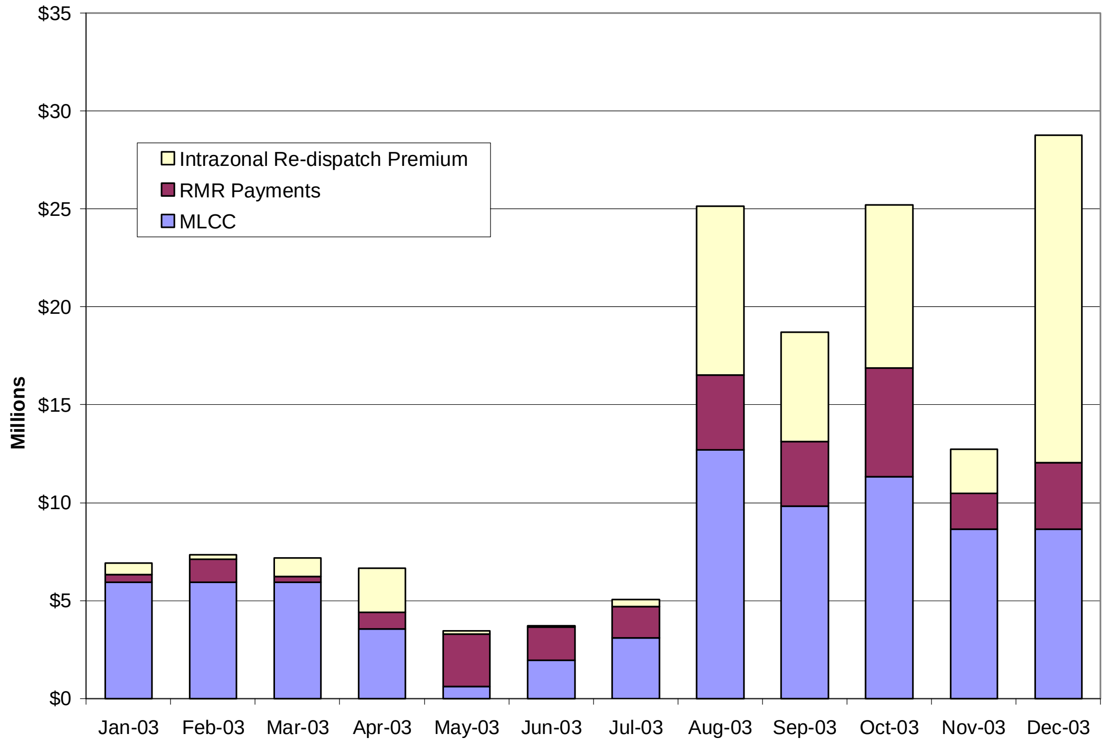
### *6.1.6 Total Intrazonal Congestion Costs*

Table 6.7 below shows the summation of all the costs that might reasonably be attributed to intrazonal congestion. Most of these costs are MLCC costs. In 2003, we estimate that there were approximately $150.8 million in intrazonal congestion costs, substantially higher than the roughly $6 million incurred in 2002. Significantly, there is a substantial increase in all the measures in August of 2003 due to the ongoing congestion at the Miguel substation. This is made clear in Figure 6.3.

**Table 6.7 Total Estimated Intrazonal Congestion Costs for 2003**

| 2003 | MLCC | RMR | Redispatch | Total |
|---|---|---|---|---|
| January | 5,944,005 | 382,896 | 571,346 | 6,898,247 |
| February | 5,944,005 | 1,156,751 | 224,536 | 7,325,292 |
| March | 5,944,005 | 283,669 | 953,571 | 7,181,245 |
| April | 3,552,598 | 856,163 | 2,233,907 | 6,642,668 |
| May | 599,563 | 2,701,241 | 145,652 | 3,446,456 |
| June | 1,946,473 | 1,711,802 | 52,796 | 3,711,071 |
| July | 3,089,376 | 1,610,059 | 350,711 | 5,050,146 |
| August | 12,712,017 | 3,794,650 | 8,646,615 | 25,153,282 |
| September | 9,815,119 | 3,304,087 | 5,598,145 | 18,717,351 |
| October | 11,324,437 | 5,547,781 | 8,329,794 | 25,202,012 |
| November | 8,626,939 | 1,834,803 | 2,268,184 | 12,729,926 |
| December | 8,626,939 | 3,416,607 | 16,733,204 | 28,776,750 |
| **Totals** | $78,125,479 | **$26,600,509** | **$46,108,461** | **$150,834,446** |

**Figure 6.3 2003 Monthly Total Intrazonal Congestion Costs**




### *6.1.7 Out of Market (OOM) Dispatches for System Reliability*

The process of balancing the grid occurs in the real-time imbalance energy market. Generators submit bids to either increment generation (sell energy to the grid) or decrement generation (buy over-supplied energy from the grid). The bid-based balancing of the grid is usually problem-free unless there are local reliability problems or bid-sufficiency problems. As a rule, under stable market conditions OOM[3] calls result from emergency conditions, such as transmission lines going down or plants tripping unexpectedly. OOM calls are infrequent since the imbalance energy required to balance the grid should be available from market-based systems such as the BEEP stack. This stack includes bids both by in-state generators and bids by out-of-state generators via intertie bids. We regard the presence of occasional OOM calls as an anomalous condition whereas the persistence of OOM calls as a situation that requires further investigation due to the possibility of market under-performance or market failure.

The pattern of incremental OOM dispatches shown as Table 6.8 is reassuringly sporadic. This indicates that during 2003 the imbalance energy market was nearly always sufficient to balance the grid and OOM calls were limited to use during system emergencies. There were only three significant OOM events in 2003, on May 28, September 22 and December 21. OOM calls on May 28 and September 22 were due to load forecast errors and associated reserve deficiencies. The OOM calls on December 21 were due to a Path 15 emergency when a 500 kV line tripped. The minor OOM call on February 23 was due to the loss of major unit during the evening ramp.

[3] This analysis is limited to purchases of incremental energy Out-of-Market from out-of-control area entities to alleviate system conditions.

**Table 6.8 Incremental OOM Calls for 2003**

| Date | INC MWh | Gross Cost | Redispatch | Avg Price | Avg Prem |
|---|---|---|---|---|---|
| Jan-03 | 0 | 0 | 0 | 0 | 0 |
| Feb-03 | 71 | 10,940 | 0 | 154 | 0 |
| Mar-03 | 0 | 0 | 0 | 0 | 0 |
| Apr-03 | 0 | 0 | 0 | 0 | 0 |
| May-03 | 1,134 | 150,813 | 29,873 | 133 | 26 |
| Jun-03 | 0 | 0 | 0 | 0 | 0 |
| Jul-03 | 0 | 0 | 0 | 0 | 0 |
| Aug-03 | 0 | 0 | 0 | 0 | 0 |
| Sep-03 | 557 | 33,718 | 17 | 61 | 0 |
| Oct-03 | 0 | 0 | 0 | 0 | 0 |
| Nov-03 | 0 | 0 | 0 | 0 | 0 |
| Dec-03 | 623 | 57,769 | 8,243 | 93 | 13 |
| **Total** | **2,385** | **$253,240** | **$38,133** | **$106** | **$16** |