7. Local Area Reliability

Though intra-zonal congestion may have many underlying causes, the resultant problem manifests itself either in the context of a generation pocket or a load pocket. In both cases, the absence of sufficient transmission access to that area means that the ISO has to solve 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 ISO's preferred long-term method for dealing with intra-zonal congestion is using RMR contracts. RMR units are dispatched where available, however should this be insufficient, then other units are dispatched out-of-sequence (OOS) if they have submitted bids or using out-of-market (OOM) calls if they have not. OOS dispatches are so called because they require the ISO to skip over lower priced real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem. Units called OOS to mitigate intra-zonal congestion are paid as-bid, which means they cannot set the real-time market-clearing price. Units within the ISO control area are subject to the Must-Offer-Obligation (MOO) whereby bids are automatically inserted for them if they fail to do so themselves. Thus, OOM calls are seldom used for intra-zonal congestion.

7.1 Re-Dispatch Costs

There are a number of different ways to measure the cost of OOS calls. The simplest is to subtract the market-clearing price from the actual price paid and multiply the result by the MWh produced. This is a broad measure, and should further analysis be required, the calculations of cost become more complex as they must be changed to fit specific generator characteristics.

7.1.1 Incremental Energy Dispatches

Gross payments for incremental energy dispatches in 2002 totaled $4.7 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 $2.9 million. In all, the ISO procured 63,683 MWh of energy at an average price of $74/MWh. These figures are shown in Table 7.1 and Figure 7.1 below. There was a substantial increase in incremental dispatches in October and November. This increase was due to a single incident involving a series of transmission line outages and contemporaneous generator outages. The events surrounding these occurrences are currently subject to investigation. This incident alone accounted for 89% of the net incremental congestion costs for the year. Were it not for these two months, the total OOS incremental dispatches would have been substantially less.

7.1.2 Decremental Energy Dispatches

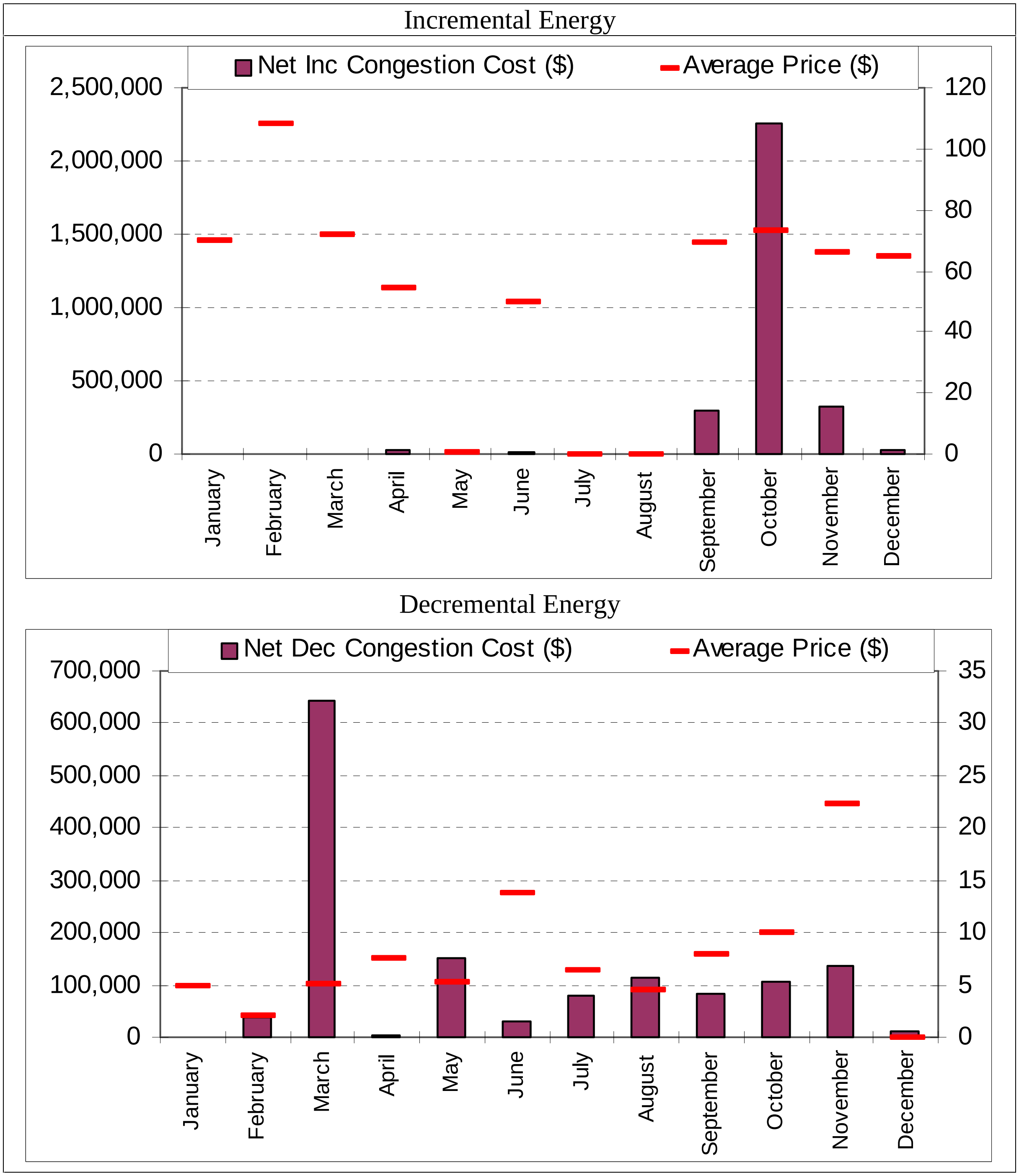
Decremental energy dispatches in 2002 totaled $297,605 (i.e. a payment of that amount to the ISO). The net cost to load of these dispatches (defined as the premium paid over the market-clearing price multiplied by the quantity procured) was $1.4 million. Decremental energy dispatches in 2002 totaled 40,808 MWh at an average price of $7/MWh. These figures are shown by month in Table 7.1 below and graphically in Figure 7.1.

Two units owned by the same company account for 80.4 percent of the net decremental congestion costs. The construction of a new power plant and the work to upgrade the transmission lines has resulted in significant congestion in the vicinity of one of the plants. Scheduled transmission upgrades in 2003 are expected to solve this problem. In addition, the ISO submitted filings to FERC with the intention of acquiring bid mitigation authority. This would allow the ISO to mitigate bids due to extraordinary circumstances and would prevent market participants from unduly profiting from intra-zonal congestion.

Table 7.1. 2002 Incremental and Decremental Energy

Incremental Energy				
Month	MWh	Actual Cost ($)	Re-dispatch Cost ($)	Average Price ($)
January	202	14,208	5,127	70
February	31	3,322	2,317	108
March	29	2,095	9	72
April	1,070	58,156	23,196	54
May	2	1	0	1
June	313	15,546	11,467	50
July	0	0	0	0
August	0	0	0	0
September	8,670	600,085	292,439	69
October	44,865	3,291,023	2,254,581	73
November	9,822	649,943	318,039	66
December	1,170	75,744	26,307	65
Totals	63,683	4,710,125	2,933,482	74
Decremental Energy				
Month	MWh	Actual Cost ($)	Re-dispatch Cost ($)	Average Price ($)
January	-15	-73	475	5
February	-1,546	-3,144	37,282	2
March	-15,951	-81,261	642,269	5
April	-348	-2,650	5,440	8
May	-5,284	-28,455	150,013	5
June	-1,297	-17,966	30,110	14
July	-2,235	-14,281	78,614	6
August	-2,978	-13,440	113,745	5
September	-3,369	-26,972	84,358	8
October	-3,543	-35,675	106,071	10
November	-3,294	-73,716	134,755	22
December	-949	28	11,012	0
Totals	-40,808	-297,605	1,394,144	7

Figure 7.1. 2002 Incremental and Decremental Energy



7.2 Locational Market Power

Locational market power problems can arise on any electric power network as a result of intra-zonal congestion and other local constraints in the transmission system, combined with concentration of ownership of generating units within "load pockets" with limited transmission capacity to the main electrical grid. When local system conditions are such that any individual generating unit, or generation from a group of units owned by only one or two suppliers, are needed to ensure local system reliability, local market power can arise, i.e., owners of specific resources needed to ensure local reliability are able to demand unreasonable prices for additional capacity and/or generation needed to ensure local reliability. Locational market power also can arise within "generation pockets" in instances where the amount of energy scheduled by one or more generators may exceed the transmission capacity of a generation pocket, thereby requiring the ISO to call upon these same generators to reduce their generation to mitigate the intra-zonal congestion created by this generation pocket.

To mitigate locational market power, California's original (and current) market design primarily relies upon Reliability Must-Run ("RMR") contracts with units located at known strategic locations on the transmission grid. In cases where intra-zonal congestion cannot be mitigated by dispatching an RMR unit for additional incremental energy, the ISO must call real-time energy bids submitted by specific units out-of-sequence (OOS) to resolve intra-zonal congestion and ensure local reliability. Although bids dispatched OOS do not set the overall market clearing price, bids accepted OOS are paid at bid price, so generators do have the ability to exercise locational market power whenever the ISO must issue OOS calls for incremental or decremental generation from just one or two specific market participants.

The concern that generators have opportunities to profit unduly from Intra-Zonal Congestion and other locational reliability constraints is not simply theoretical; the ISO has observed this behavior on numerous occasions since its inception, and has developed a number of measures to assess and track the costs of intra-zonal congestion and locational market power. The simplest of these is the re-dispatch cost calculations shown in Table 7.1, however the calculation of Potential Market Power requires additional refinement.

7.2.1 Potential Market Power Approach (PMP)

As in the calculation of re-dispatch costs, the calculation of PMP evaluates the accepted bids against a benchmark. For thermal generators this benchmark is set at the higher of the Market Clearing Price and their marginal cost, which is calculated using the relevant generator heat rate and a proxy for fuel price[1]. The PMP calculation thus becomes the difference between this hybrid benchmark and the price paid, multiplied by quantity. This PMP measure is useful in an investigative framework, as it creates a subset of the re-dispatch costs (i.e. the costs benchmarked against the MCP) which highlights the market power that generators are able to exercise due to their location. The results of these calculations are shown in Table 7.2. On the incremental energy side potential market power costs are shown to be approximately

[1] Potential Market Power calculations for non-thermal generators were not calculated due to the difficulty of establishing reliable opportunity costs for these units.

$2 million, while on the decremental energy side potential market power costs are approximately $870,000.

Table 7.2. 2002 Potential Market Power

Incremental Energy					
Month	MWh	Actual Cost ($)	Re-dispatch Costs (MCP Benchmark)	Potential Market Power	% of Re-dispatch
January	202	14,208	5,127	5,013	98
February	31	3,322	2,317	1,967	85
March	29	2,095	9	0	0
April	1,070	58,156	23,196	18,937	82
May	2	1	0	0	0
June	313	15,546	11,467	5,402	47
July	0	0	0	0	0
August	0	0	0	0	0
September	8,670	600,085	292,439	221,295	76
October	44,865	3,291,023	2,254,581	1,587,772	70
November	9,822	649,943	318,039	211,853	67
December	1,170	75,744	26,307	17,745	67
Totals	66,174	4,710,125	2,933,482	2,069,984	71
Decremental Energy					
Month	MWh	Actual Cost ($)	Re-dispatch Costs (MCP Benchmark)	Potential Market Power	% of Re-dispatch
January	-15	-73	475	349	73
February	-1,546	-3,144	37,282	6,506	17
March	-15,951	-81,261	642,269	515,395	80
April	-348	-2,650	5,440	4,231	78
May	-5,284	-28,455	150,013	81,339	54
June	-1,297	-17,966	30,110	10,534	35
July	-2,235	-14,281	78,614	35,485	45
August	-2,978	-13,440	113,745	46,507	41
September	-3,369	-26,972	84,358	63,859	76
October	-3,543	-35,675	106,071	64,542	61
November	-3,294	-73,716	134,755	28,570	21
December	-949	28	11,012	11,012	100
Totals	-40,808	-297,605	1,394,144	868,331	62

7.3 Reliability Must Run

To mitigate locational market power, California's original (and current) market design primarily relies upon Reliability Must-Run ("RMR") contracts with units located at known strategic locations on the transmission grid. Through an annual planning process, the ISO 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, provide adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. Units receiving RMR designation are then subject to a pro forma RMR contract agreement, which provides specific terms and conditions under which the ISO can dispatch such units on a day-ahead basis or in real-time to ensure that sufficient energy and on-line generation within each RMR area is available to meet local reliability requirements. RMR contracts also 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 contracts provide a means of mitigating one form of the exercise of local market power (the "Inc Game") in cases where incremental energy is needed for local reliability by ensuring that the ISO has the ability to call upon RMR units to provide energy at a pre-agreed, cost-based rate if the level of RMR generation needed to meet local reliability requirements is not scheduled through a market transaction. In the absence of RMR contracts, generation owners could, under certain load conditions, bid capacity at a very high price in the real-time energy market and force the ISO to meet local reliability requirements by calling for generation out-of-sequence at these uncompetitive high bid prices.

7.3.1 Estimating Intra-Zonal RMR Costs

RMR units receive annual fixed payments from the ISO for all kinds of interrelated reliability needs and there is only an imprecise way to separate the portion of intra-zonal congestion costs from the total of these fixed payments. We estimate the RMR costs attributable to intra-zonal congestion as the net variable cost payments for the nonnegative value of RMR real time requirements less hour-ahead scheduled energy. We calculate the net variable cost as the higher of zero and the difference between the RMR variable payment rate and the real time ex-post imbalance energy price. Table 7.3 shows the distribution of RMR intra-zonal congestion cost at various sub-zones in ISO control area over the last two years.

Table 7.3. Monthly RMR Intra-zonal Costs

Zone	2001 RMR Intra-Zonal Cost		2002 RMR Intra-Zonal Cost	
	MWh	Cost	MWh	Cost
Fresno Area	1,148.86	$125,702	1,021.36	$29,359
Greater Bay Area	66,670.06	$419,985	53,409.92	$1,102,749
Humboldt	6,248.84	$453,342	56,662.19	$1,076,921
LA	7,201.68	$526,698	98,561.16	$1,186,128
North Bay Area	2,155.54	$369	1,057.28	$0
San Diego	46,152.23	$1,328,623	102,856.9	$1,327,202
San Francisco	79,749.18	$1,345,378	116,521.6	$1,351,571

Figure 7.2 presents monthly RMR intra-zonal costs from January 2001 to November 2002. These costs were highest for September 2002 at $1.42 million dollars when station work affected two separate lines, namely Lewis-Serrano No. 2 and Serrano-Villa Park No. 2. The ISO dispatched RMR units in Los Angeles in response to the events.

Figure 7.2. Intra-Zonal Costs Associated with RMR Units