6 Reliability Costs

Observable reliability costs – Minimum Load Cost Compensation (MLCC), Reliability Must Run (RMR) costs, and Out-of-Sequence (OOS) redispatch costs – were dramatically lower in 2007 than in previous years, totaling approximately $101 million, a decrease of 51 percent from the 2006 level. However, these costs do not include Reliability Capacity Service Tariff (RCST) charges[1] or capacity payments to meet Resource Adequacy (RA) requirements. Upgrades to the Southern California transmission grid in 2006 and termination of RMR contracts both appear to have contributed significantly to the decrease in reliability costs. In addition, 2007 was a year of relatively few construction outages and relatively mild weather, in which the grid required minimal workarounds to ensure reliability, save for two weeks in late October when wildfires swept through Southern California and caused numerous transmission outages. In contrast, 2006 saw multiple outages, as key transmission upgrades were completed, and an extraordinarily hot summer, in which loads were estimated to be in the top two percentile of probability.

6.1 Overview

Scheduling Coordinators (SCs) submit day-ahead/hour-ahead generation and load schedules to the CAISO. Due to differences in the price and availability of power in different locations, these schedules vary daily and, collectively, may exceed the transfer capability of grid facilities within the congestion zones. However, the CAISO's Day Ahead and Hour Ahead Congestion Management Markets only manage congestion between zones, not within zones. This allows SCs to submit day-ahead/hour-ahead schedules that require transmission within a zone that is not physically feasible, and, as a consequence, creates the need for CAISO operators to have to manage intra-zonal congestion in real-time. Managing large amounts of intra-zonal congestion in real-time creates operational and reliability challenges and can result in significant costs.

Intra-zonal congestion costs are comprised of three components:

1) Minimum Load Cost Compensation (MLCC).[2] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[3]

2) Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.

3) Costs of Out-of-Sequence (OOS) dispatches.

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[1] See Chapter 1 and Section 6.3.2 for discussion of Resource Adequacy (RA) and Reliability Capacity Services Tariff (RCST).

[2] MLCC payments are cost-based and are calculated as variable cost for providing the minimum load energy plus a $6/MWh O&M adder.

[3] Pursuant to Amendment 60 to the CAISO Tariff, MLCC costs are categorized into three categories (system, zonal and local), which reflect the primary reason the unit was denied a must-offer waiver. Both zonal and local MLCC costs are included as the MLCC component of intra-zonal costs.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated, where transmission within the zone is not sufficient to allow access to lower-priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within it. Intra-zonal congestion can also occur due to pockets in which generation is clustered together, without the transmission necessary for the energy to flow out of that pocket to load. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Such congestion is inefficient if the market costs due to the transmission congestion (i.e., the cost imposed by the fact that load cannot be served by the lowest-cost supplier(s), and instead must be served by higher-cost suppliers) exceed the cost of a transmission upgrade that could alleviate the congestion.

Typically, there is limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal congestion is often coupled with locational market power. Consequently, methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise local market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often constrains-on or commits long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments and/or RA capacity payments. This forward unit commitment process helps to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO Real Time Market.[4] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids OOS;[5]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-of-Market (OOM).

Units incremented OOS to mitigate intra-zonal congestion are paid the higher of their bid price or the zonal market clearing price (MCP). They do not set the real-time market clearing price. Units decremented OOS to mitigate intra-zonal congestion are charged the lower of their decremental reference price or the zonal market-clearing price. They also do not set the real-time market clearing price. Inter-tie bids taken OOS are settled on an as-bid basis.

[4] 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.

[5] The term "out-of-sequence" refers to the fact that such dispatches require the CAISO, when incrementing (or decrementing) generation, to bypass lower (or higher) priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

In addition, OOS bids are subject to local market power mitigation. Specifically, incremental OOS dispatches are subject to a conduct test where accepted OOS bids priced greater than the minimum of $50 or 200 percent above the interval MCP are mitigated to their reference price for that OOS dispatch and are settled at the greater of the mitigated bid price or the interval MCP. To the extent decremental bids are dispatched OOS for intra-zonal congestion, such dispatches will be based on decremental reference levels rather than market bids and will be settled based on the lower of the unit's decremental reference price and the real-time interval MCP.

6.2 Points of Intra-Zonal Congestion

Both NP26 and SP15 experienced intra-zonal congestion in 2007. The largest congestion point within NP26 was the Humboldt area on the North Coast of California. Intra-zonal congestion within SP15 was predominately at locations where intra-zonal congestion has been an issue in recent years. These include the following:

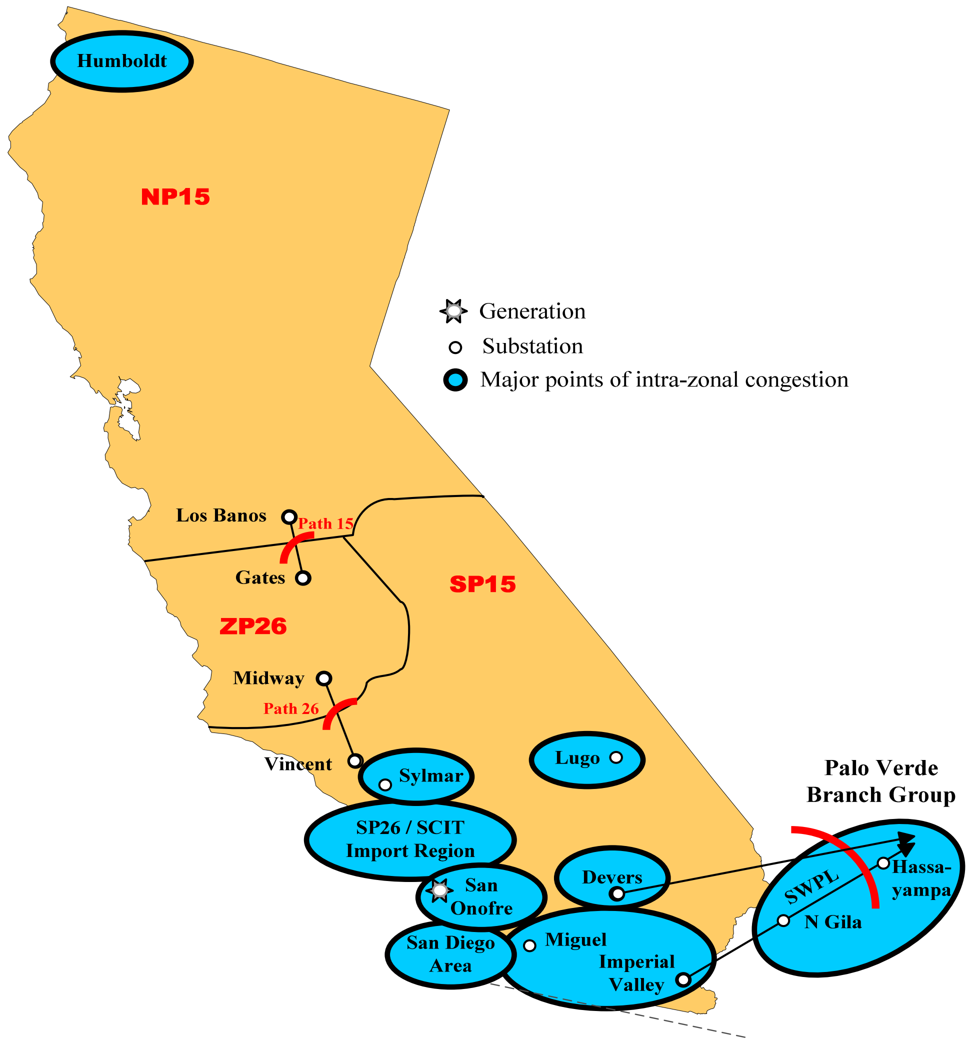
- Miguel, Imperial Valley Banks, and SWPL, which are considered in the San Diego Transmission Network Analysis (TNA) procedure that manages flows through the greater San Diego area that also impact the greater SP15 area. The Miguel and Imperial Valley substations provide transmission of power to Southern California load from generation facilities located in Mexicali, Baja California, Mexico, and imports on the Southwest Power Link (i.e., North Gila to Imperial Valley).

- South of the Lugo substation, near Hesperia. Power from the Hoover Dam in Nevada and newer combined-cycle facilities in California and Nevada interconnect to the Southern California grid at this point, often resulting in congestion.

- Palo Verde / Devers Branch Group. This was impacted in October by shifts in power flow due to the wildfires and SWPL outage, and was also forced out of service in late November and early December. While this is an inter-zonal, not intra-zonal, transmission corridor, the CAISO did rely on non-market mechanisms to manage reliability on this facility in the fourth quarter.

Figure 6.1 provides a representation of the CAISO Control Area's key historical intra-zonal congestion locations.

Figure 6.1 Key Points of Intra-Zonal Congestion



6.3 Reliability Management Costs

Intra-zonal congestion and reliability costs were significantly lower in 2007 than in previous years, due largely to new infrastructure improvements that were completed in previous years. For example, a key upgrade to the Lugo-Serrano transmission corridor, which brings power from Las Vegas area generation into the Los Angeles and Orange County metropolitan areas, was completed in mid-2006. While CAISO customers incurred approximately $15 million in MLCC costs for this path in 2006 due to construction outages, the work contributed significantly to the 51 percent decrease in reliability management costs between 2006 and 2007.

Measurable intra-zonal congestion management costs include three components: Minimum-Load Cost Compensation for intra-zonal (non-system) reasons, Reliability Must Run variable costs associated with real-time congestion management, and Out-of-Sequence redispatch costs. Table 6.1 shows monthly and annual total estimated intra-zonal congestion management costs for 2005 through 2007, itemized by these three components. While MLCC costs and RMR costs declined in 2007 by approximately $65 million and $54 million, respectively, these savings were offset to some extent by an increase in redispatch costs of approximately $13 million.

Table 6.1 Total Estimated Intra-Zonal Congestion Costs for 2005-2007 ($MM)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**
Jan	$ 8	$ 10	$ 3	$ 3	$ 13	$ 2	$ 6	$ 4	$ 2	$ 17	$ 27	$ 6
Feb	$ 4	$ 8	$ 2	$ 3	$ 15	$ 1	$ 3	$ 2	$ 2	$ 10	$ 25	$ 4
Mar	$ 3	$ 11	$ 2	$ 5	$ 13	$ 1	$ 3	$ 3	$ 1	$ 11	$ 27	$ 4
Apr	$ 6	$ 27	$ 2	$ 5	$ 8	$ 2	$ 3	$ 6	$ 2	$ 14	$ 41	$ 6
May	$ 14	$ 12	$ 2	$ 5	$ 3	$ 1	$ 2	$ 1	$ 2	$ 21	$ 16	$ 4
Jun	$ 7	$ 15	$ 3	$ 2	$ 4	$ 1	$ 0	$ 0	$ 1	$ 9	$ 19	$ 5
Jul	$ 13	$ 14	$ 7	$ 5	$ 2	$ 1	$ 1	$ 0	$ 2	$ 19	$ 17	$ 10
Aug	$ 14	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 24	$ 8	$ 4
Sep	$ 8	$ 3	$ 2	$ 6	$ 2	$ 0	$ 3	$ 0	$ 1	$ 17	$ 5	$ 4
Oct	$ 13	$ 1	$ 10	$ 8	$ 3	$ 6	$ 4	$ 1	$ 8	$ 25	$ 5	$ 25
Nov	$ 12	$ 1	$ 5	$ 5	$ 6	$ 3	$ 6	$ 0	$ 4	$ 23	$ 7	$ 12
Dec	$ 11	$ 2	$ 5	$ 16	$ 7	$ 8	$ 5	$ 0	$ 4	$ 32	$ 9	$ 17
Total	**$ 114**	**$ 109**	**$ 44**	**$ 72**	**$ 80**	**$ 26**	**$ 36**	**$ 17**	**$ 30**	**$ 222**	**$ 207**	**$ 101**

6.3.1 Minimum Load Cost Compensation

Pursuant to a FERC Order issued May 25, 2001,[6] and subsequent Orders, the CAISO provides Minimum Load Cost Compensation to generators that apply for waivers of the Must-Offer Obligation but are denied, and thus are required to be on-line at minimum load for the following operating day. In such cases, the CAISO compensates the generators for their minimum load costs, based upon unit operating costs and natural gas prices, where applicable. In addition, generators that are neither RA nor RCST resources, and whose waiver requests are denied, are also entitled to receive the real-time price for energy supplied while operating at minimum load. Units subject to the Must-Offer Obligation are required to bid all unloaded capacity into the CAISO Real Time Market. To encourage units subject to must-offer to bid into the Ancillary Services Market, the CAISO filed and FERC approved Amendment 60. This tariff change enables generators to keep both ancillary services revenues and MLCC.

Table 6.2 shows average must-offer and RA waiver denial capacity and total monthly costs in 2006 and 2007, as well as the imbalance energy payments that these generators received for their minimum-load energy based on real-time market prices. The costs shown in Table 6.2 also include MLCC costs for "system" reliability reasons in addition to intra-zonal reasons; these system commitments account for the differences among the totals in Table 6.1 and Table 6.2. Note that all costs exclude resource adequacy contract payments, which are negotiated bilaterally between utilities and generation owners, and thus are not visible to the CAISO.

[6] 95 FERC 61,275; 95 FERC 61,418, etc. (2001).

Table 6.2 Must-Offer Waiver Denial Capacity and Costs

	2006			2007		
Month	Average MW*	MLCC ($MM)	Imbalance ML Energy Payments ($MM)**	Average MW*	MLCC ($MM)	Imbalance ML Energy Payments ($MM)**
Jan	1,065	$ 10.9	$ 4.0	1,054	$ 3.3	$ 0.5
Feb	965	$ 8.6	$ 2.8	848	$ 1.9	$ 0.2
Mar	1,323	$ 11.6	$ 4.7	797	$ 2.3	$ 0.5
Apr	2,444	$ 27.3	$ 13.7	846	$ 2.5	$ 0.2
May	1,331	$ 12.7	$ 6.8	697	$ 1.7	$ 0.0
Jun	2,478	$ 18.3	$ 2.9	1,541	$ 5.6	$ 1.1
Jul	2,150	$ 19.6	$ 7.1	1,951	$ 8.8	$ 2.2
Aug	879	$ 4.9	$ 0.5	1,484	$ 4.0	$ 0.5
Sep	796	$ 2.8	$ 0.2	1,120	$ 3.7	$ 0.5
Oct	309	$ 0.8	$ 0.0	1,844	$ 10.7	$ 3.3
Nov	391	$ 1.1	$ 0.1	1,254	$ 4.8	$ 0.4
Dec	445	$ 2.1	$ 0.1	975	$ 5.4	$ 0.0
Annual Total	**1,215**	**$ 120.7**	**$ 42.8**	**1,201**	**$ 54.7**	**$ 9.6**

* Average maximum daily capacity of units on must-offer waiver. Includes minimum operating level plus unloaded capacity.

** Uninstructed energy payment for minimum load energy received by generator. Since MLCC covers full operating costs, this represents surplus revenue for the generator, or contribution to fixed costs.

CAISO operators issued unit commitments for a variety of reasons in 2007, with no one particular reason predominating across the year. Certain commitment reasons have been cited consistently for several years, particularly during summer and high-load periods. These reasons include:

- System capacity requirements, which are charged proportionally to all LSEs.
- Southern California capacity requirements, which are charged proportionally to SP15 zonal customers.
- Southern California area capacity to ensure sufficient resources are available when the Southern California Import Transmission (SCIT) nomogram, a physical limitation on power imports into Southern California, is binding. These commitment costs are generally charged to zonal customers.
- Local Los Angeles and Orange County area requirements when flows through the Lugo Substation, through which energy from the Las Vegas and Hoover Dam areas pass, are constrained. This was prevalent June through September of 2007. Costs for this capacity typically are allocated locally to area load.

A key transmission upgrade to route power between the Lugo and Serrano substations through the Mira Loma substation was completed in April 2006. This work required multiple clearances and commitment costs over several months in 2005 and early 2006. Its completion resulted in a decrease in MLCC for Lugo-area reasons to approximately $6.9 million in 2007, from $35.2 million in 2006.

Other reasons were event-specific in 2007 and tended to occur over short periods of time. As these happened to occur later in the year, the bulk of costs were incurred between July and December. For example:

- Commitments for the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) load-serving areas for reliability in those areas were issued during the winter and spring. As discussed below, the CAISO was able to eliminate several RMR contracts in this region due to the fact that generation capacity needed for reliability needs was procured by LSEs in meeting the resource adequacy requirements imposed by the CPUC. Reliability requirements for these resources are particularly high in the winter and spring, when Southern California load relies heavily on relatively inexpensive imports, and conserves internal high-cost and emission-constrained resources for summer use. Costs for these commitments are primarily charged to zonal (SP15) customers.

- Beginning November 2007, the CAISO frequently has made additional unit commitments for regional requirements based on a transmission network analysis of the transmission facilities generally in or around the SDG&E service territory (San Diego TNA) and other power flow analysis which jointly indicated additional resources were required to support reliability at Miguel Banks. Because these commitments are required to mitigate regional reliability issues at Miguel Banks, costs for these unit commitments are allocated to zonal (SP15) customers pursuant to FERC Order on Rehearing on Amendment 60.[7]

- Wildfires in October 2007 across Southern California resulted in significant transmission losses, and necessitated primarily local commitment of resources. At certain points, fires nearly or completely eliminated high-voltage transmission, and local generation supplied all load. Commitment costs were primarily local.

- A forced outage of one bank at the Vincent substation resulted in Path 26 being derated intermittently between July 11 and August 8. This resulted in approximately $6 million in primarily zonal costs within the SP15 region in July, for both zonal capacity and SCIT management.

- Other outages, derates, and clearances for transmission work, the costs of which typically are allocated locally.

[7] *Cal. Indep. Sys. Operator,* 121 FERC ¶ 61,193 (2007).

Figure 6.2 Annual MLCC Costs by Reason, 2006-2007

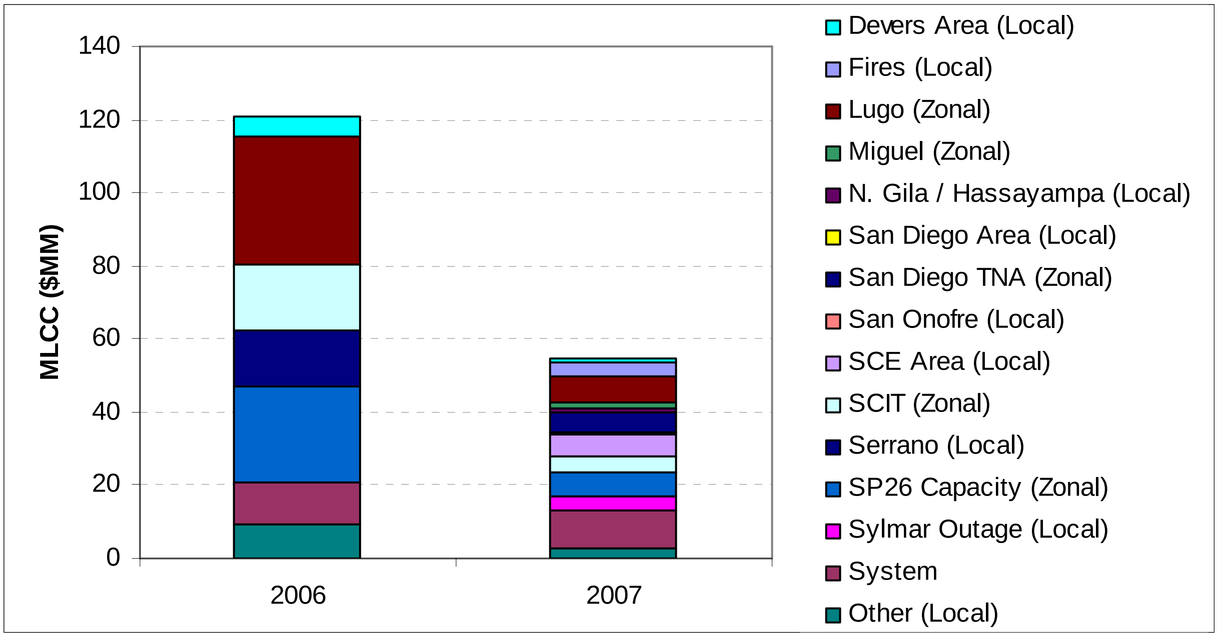


Figure 6.3 Monthly MLCC Costs by Reason, 2007

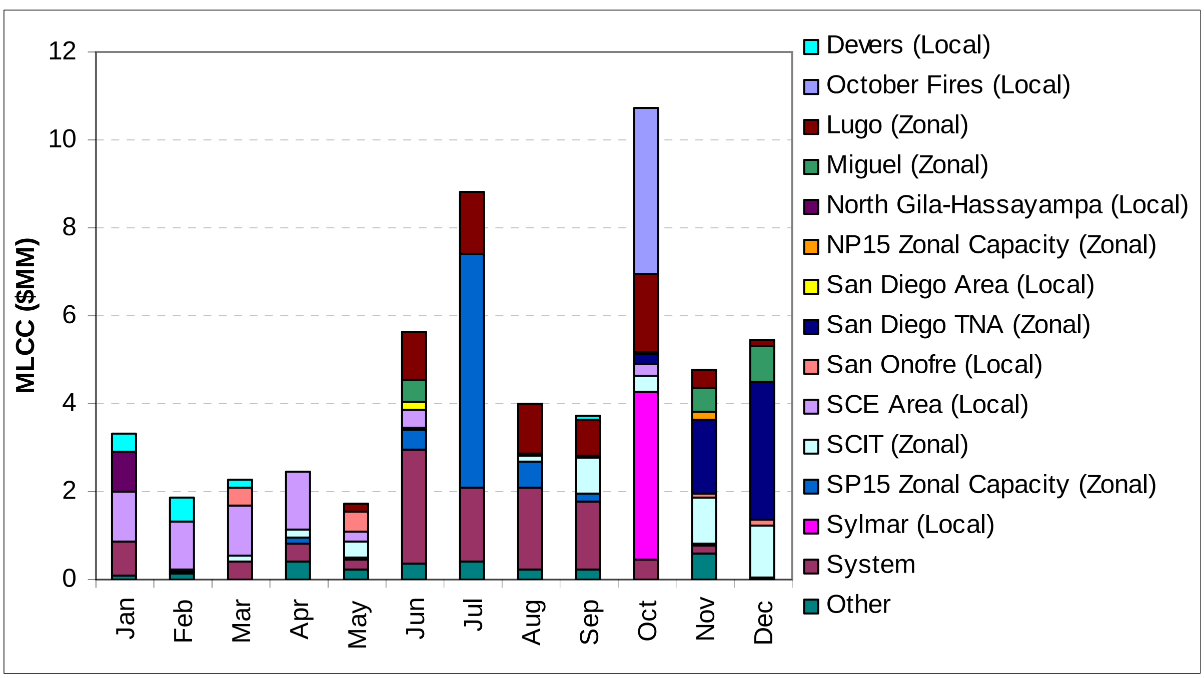
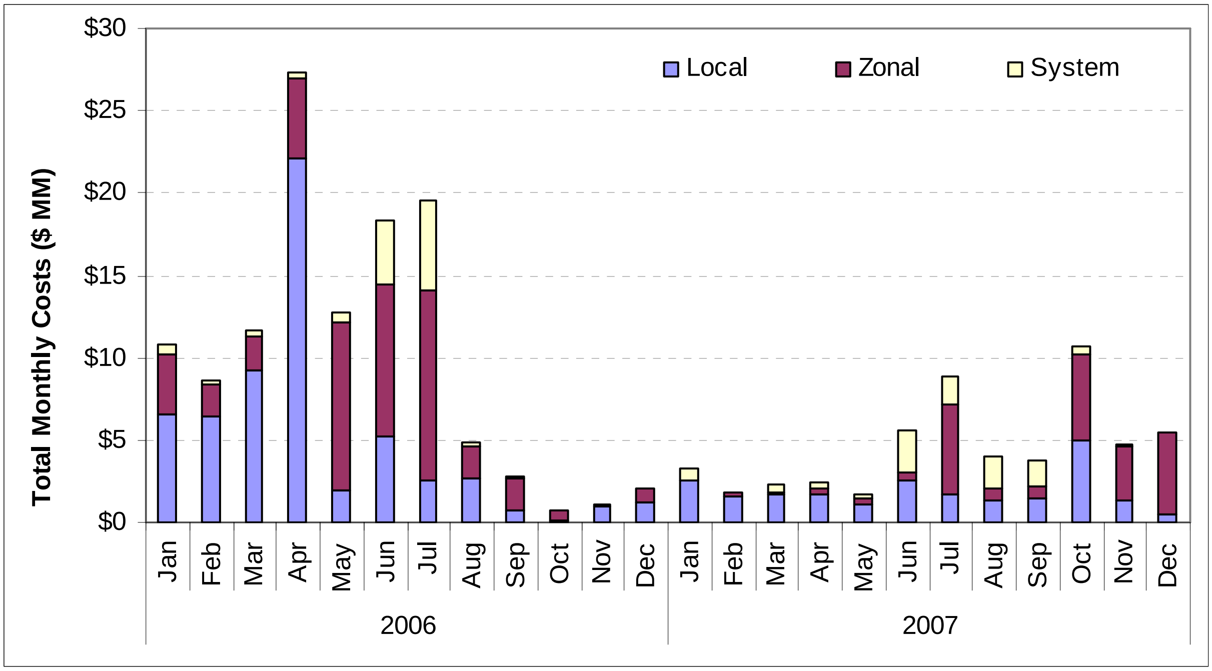


Figure 6.4 shows average daily capacity cost of waiver denials by commitment charge type (local, zonal, and system). The monthly totals of all three reason categories equals the values

shown in Table 6.2. The sharp decline in zonal requirements following the summer of 2006 was due largely to the completion of the aforementioned Southern California transmission upgrade projects.

Figure 6.4 Total Monthly MLCC Payments for All Reasons (Local, Zonal, and System), 2006-2007

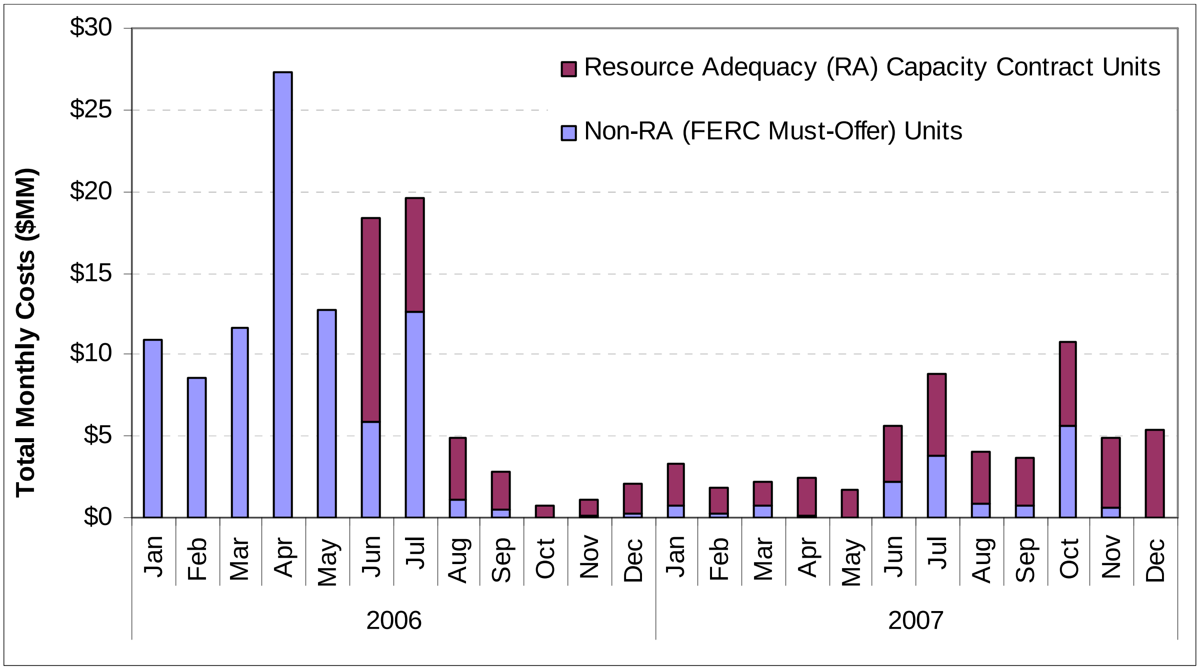


In 2006, the Resource Adequacy (RA) programs developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserves. In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines the way RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecasted load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined for each CPUC-jurisdictional LSE load forecast based on an allocation of each LSE’s coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE’s forecast load was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation. Most frequently-committed units are now covered under RA capacity contracts. Non-RA units were committed under the Must-Offer Obligation in 2007 occasionally, usually to meet system requirements and when needed in October during the series of wildfires. Figure 6.5 shows the breakdown of costs between commitment of units with and without RA contracts. As noted previously, these costs do *not* include RA contract payments, which are bilateral and outside the purview of the CAISO, nor do they include RCST payments which are covered in the next section of this chapter.

Figure 6.5 Total Monthly MLCC Payments to Must-Offer vs. RA-Contracted Units in 2006-2007



6.3.2 *Reliability Capacity Service Tariff (RCST) Charges*

Beginning June 1, 2006, the CAISO implemented a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST also provides the CAISO with the authority to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

The purpose of the RCST, which was ultimately approved by the FERC, was to provide a mechanism by which the reliability needs of the CAISO were met and that ensured generators providing reliability services would be appropriately compensated, thereby reducing the likelihood that units critical for reliability will be mothballed or shut down. Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. The capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. The net payment was designed to reflect a reasonable price for "backstop" capacity and encourage LSEs and generators to engage in longer term contracting and not rely on the must-offer mechanism. This net RCST capacity payment is calculated on a monthly basis by allocating these annual fixed costs to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process for four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

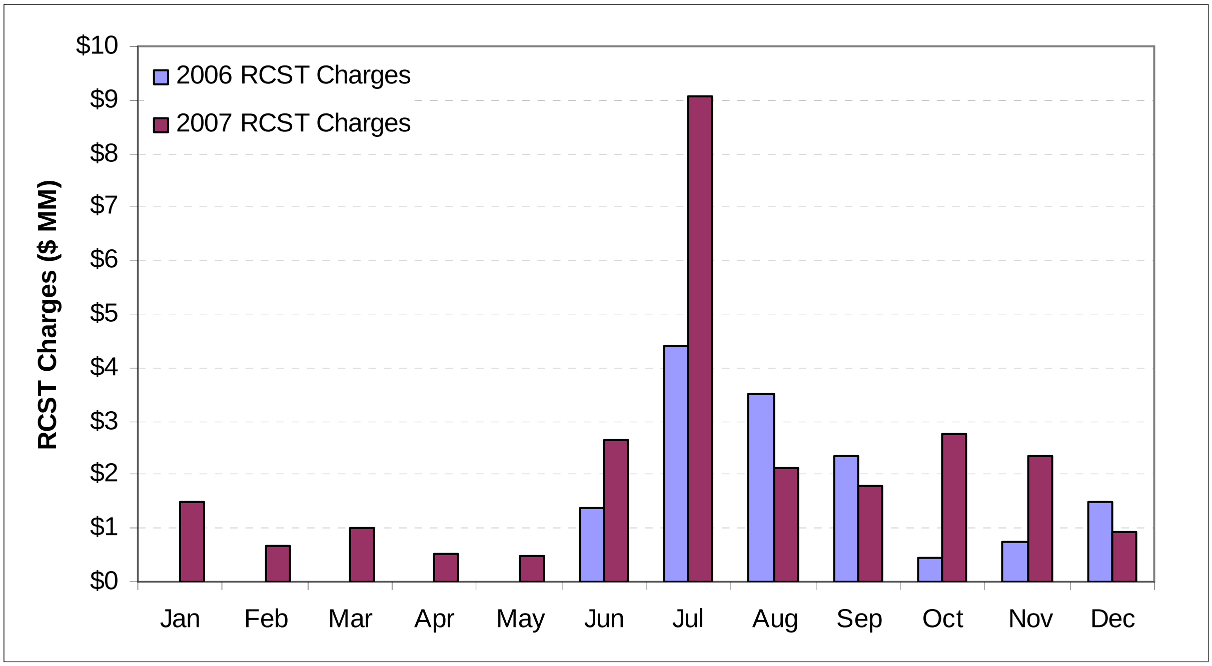
- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. As discussed below, approximately $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with more than 75 percent of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the CAISO's current local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[8]

For 2006 and 2007, there was only one instance where the RCST Capacity Payment (not the Daily RCST Capacity Payment) was warranted, which occurred in 2006 and totaled just over $600,000 in total payment. The vast majority of costs associated with the RCST have been in Daily RCST Capacity Payments, which can be seen in Figure 6.6.

[8] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs which are in excess of $50 or 200 percent of the interval MCP are mitigated to their reference price and settled on the greater of the mitigated bid or the interval MCP. Under the RCST tariff provisions, bids mitigated under these LMP provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

Figure 6.6 Daily RCST Capacity Payments by Month for 2006-2007



The RCST was in effect only for the last six months of 2006. During this period, the Daily RCST Capacity Payments totaled $14.3 million. In 2007, the comparable RCST payments totaled $25.9 million for the full twelve months, with $21.7 million of that occurring in the last six months. Comparing the June – December periods for 2006 and 2007, the Daily RCST Capacity Payments increased 52 percent. The increase in daily RCST capacity payments in 2007 can be attributed to a number of factors, including increased use of short-start units to provide system energy, increased use of resources to provide capacity in SP15, and increases in the basis of the 1/17th capacity payment, resulting in lower Peak Energy Rents in the summer months in 2007.

6.3.3 Reliability Must-Run (RMR) Costs

To mitigate local market power and to ensure that local reliability requirements are met, California's current market design relies upon 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 (prior to real-time), or incremented in real-time either for local reliability or for intra-zonal congestion. RMR units cannot be pre-dispatched for intra-zonal congestion.

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[9]

Since 2006, the CAISO has significantly reduced its portfolio of RMR resources. This has resulted in a decline in total RMR costs of approximately 70.7 percent between 2006 and 2007. Table 6.3 shows fixed and variable RMR costs by month in 2007, and further divides variable cost payments into costs associated with pre-dispatch RMR energy for local reliability, and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[10] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy.

Table 6.3 Monthly RMR Contract Energy and Costs in 2007*

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Pre-Dispatch Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan	61	29	$ 8	$ 4	$ 2	$ 13
Feb	41	20	$ 7	$ 2	$ 1	$ 10
Mar	32	31	$ 8	$ 2	$ 1	$ 11
Apr	21	23	$ 6	$ 1	$ 2	$ 9
May	57	7	$ 5	$ 3	$ 1	$ 8
Jun	36	31	$ 5	$ 2	$ 1	$ 8
Jul	60	16	$ 5	$ 2	$ 1	$ 8
Aug	84	24	$ 5	$ 3	$ 1	$ 9
Sep	64	12	$ 6	$ 3	$ 0	$ 8
Oct	98	201	$ 5	$ 3	$ 6	$ 15
Nov	55	126	$ 5	$ 2	$ 3	$ 9
Dec	66	154	$ 5	$ 3	$ 8	$ 16
2007 Total	**675**	**676**	**$ 70**	**$ 29**	**$ 26**	**$ 125**
% Δ from 2006	-76.1%	-63.7%	-73.1%	-66.9%	-67.3%	-70.7%

* Includes only dispatches under contract option.

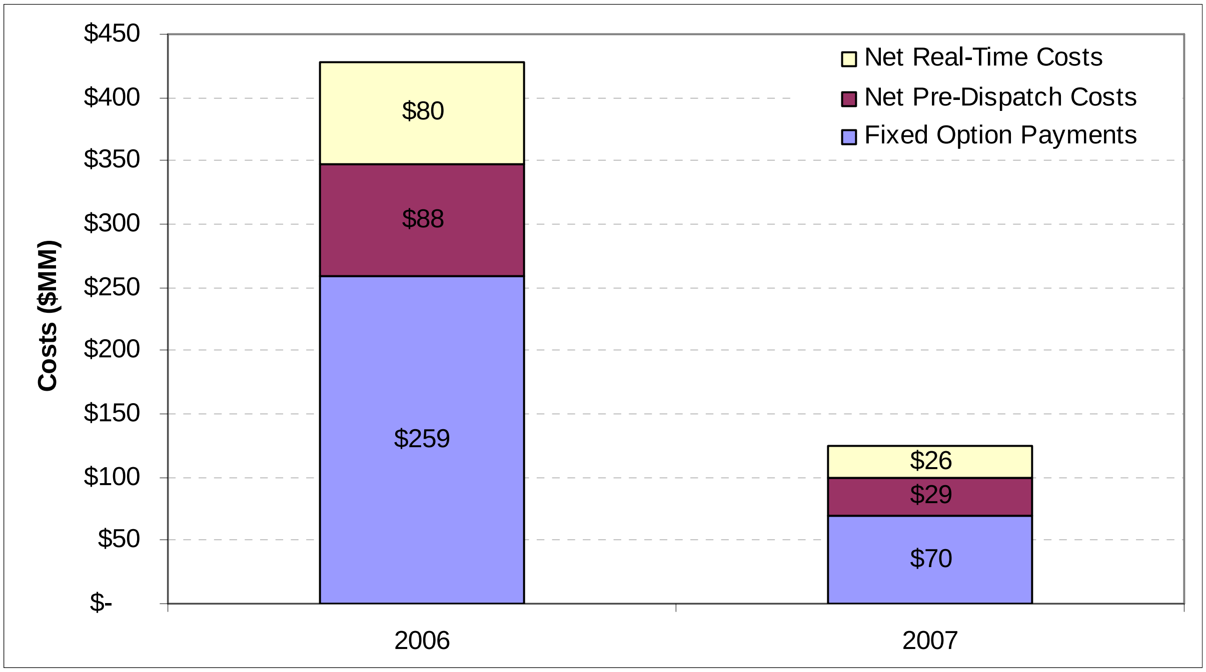
Most of the savings in RMR contract costs is attributable to a large reduction in the amount of generation capacity under RMR contracts, from approximately 9,300 MW in 2006 to 3,300 MW in 2007. As previously discussed in Chapter 1, the significant decline in the amount of generation capacity under RMR contracts was brought about through the introduction of Local Resource Adequacy requirements. With more local resources being procured through Resource Adequacy contracts, the CAISO was able to significantly decrease its RMR designations, which in turn resulted in a significant decrease in RMR fixed option payments, from approximately $259 million in 2006 to $70 million in 2007. In addition, the reduction in RMR contracted units, as well as grid upgrades and milder weather, resulted in substantially lower RMR variable cost payments (pre-dispatch and real-time dispatch). RMR variable costs

[9] Units under Condition 1 of the RMR contract are free to select the "Market Option" when receiving an RMR dispatch on a day-ahead or hour-ahead basis, in which case they keep all revenues from sales of this energy and do not receive any reimbursement for variable operating costs.

[10] Since selection of RMR units and pre-dispatch of RMR units is based on local reliability requirements, these costs are not specifically associated with intra-zonal congestion. While annual designation of RMR units and pre-dispatch of RMR units to meet local area reliability requirements may reduce intra-zonal congestion in real-time, these costs would be incurred even if intra-zonal congestion did not occur in real-time. Thus, it is more appropriate to exclude costs associated with the FOP and pre-dispatch of RMR units from intra-zonal congestion costs.

totaled approximately $55 million in 2007, compared to $168 million in 2006. In sum, total RMR costs decreased in 2007 to approximately $125 million, from approximately $428 million in 2006 (Figure 6.7). This continued a trend of declining RMR costs that has persisted since 2004.

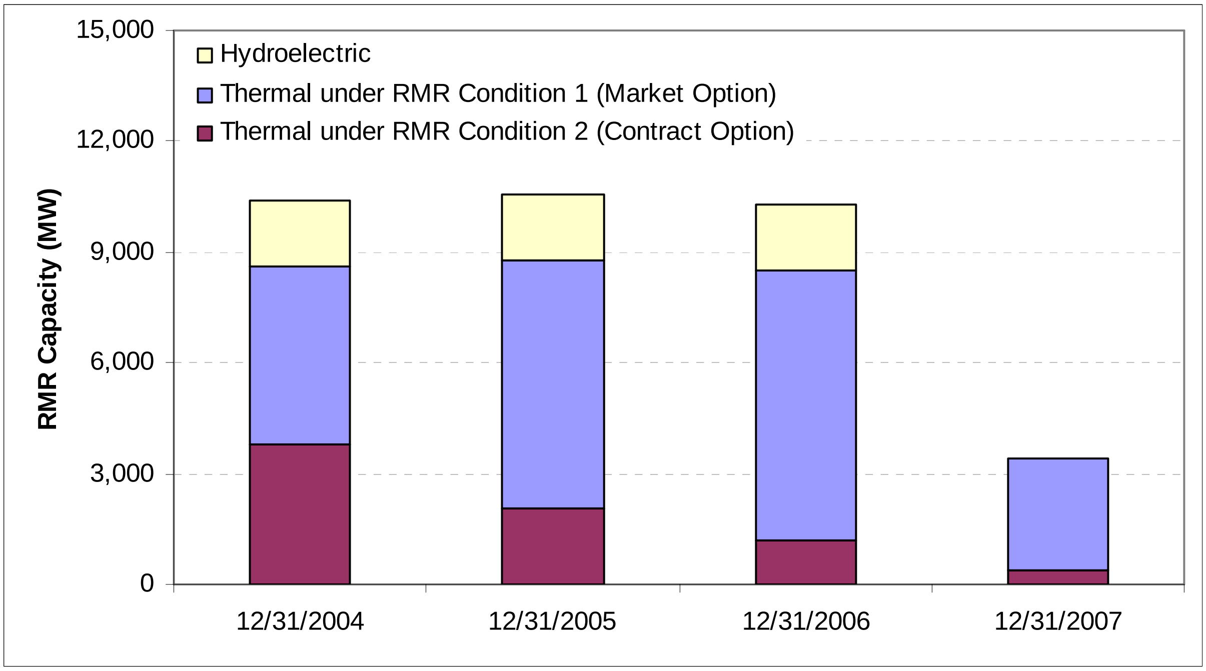
Figure 6.7 Total RMR Costs, 2006-2007



The portion of RMR unit capacity selecting Condition 2 (non-market) of the pro forma RMR contract continued to decrease, which also contributed to lower variable cost payments. RMR-providing generation owners may select either Condition 1 or 2 contracts. Condition 1 designations entitle the generation owner to participate in the market, and, if dispatched for RMR, to select on a daily basis whether to collect variable contract-based rates (Contract Path) or market revenues (Market Path). Because Condition 1 units have market opportunities, they receive a lower monthly FOP.[11] Condition 2 effectively is a tolling agreement between the CAISO and the generation owner, where the owner receives a higher FOP, but receives cost-based payments for its energy and cannot participate in the market unless given an RMR dispatch. Condition 2 unit capacity accounted for approximately 10.3 percent of total RMR-contracted unit capacity by the end of 2007, compared to 11.8 percent at the end of 2006 (Figure 6.8).

[11] RMR Condition 1 revenues from dispatch under the Market Path are not included in the calculation of reliability costs, but are included as real-time market costs in the calculation of total wholesale market costs in Chapter 2.

Figure 6.8 RMR Capacity by Resource and Contract Type, 2004-2007



6.3.4 Out-of-Sequence (OOS) Costs

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is the difference between the price paid to the resource for OOS energy (generally, their bid price) less the market clearing price (the cost of balancing the OOS energy). For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental OOS energy.[12]

As shown in Table 6.4, net redispatch costs of incremental dispatches to LSEs, or the costs in excess of real-time market prices, were approximately $20.8 million in 2007, compared to $4.3 million in 2006. In all, the CAISO procured 365 GWh of incremental OOS energy at an average price of $107.36/MWh, or $56.89/MWh above market.

Table 6.5 shows decremental OOS statistics. Decremental redispatch costs, or the amount of money below the market price that resources save when the CAISO reduces their output in order to avoid intra-zonal congestion, totaled approximately $9.7 million in 2007, compared to

[12] This discussion excludes OOS and OOM dispatches for system conditions, which totaled approximately $4.9 million in redispatch costs in 2007. These dispatches were largely incremental dispatches to RMR Condition 2 units during the summer heat wave, which under the RMR contract are not required to bid, and decremental dispatches to pump storage units to offset over-generation during the spring months.

$13.2 million in 2006. In all, the CAISO decremented 480.8 GWh of OOS energy at an average price of $45.19/MWh, or $20.22/MWh below market.

Table 6.4 Incremental OOS Congestion Costs in 2007

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Mitigation Savings ($)	Average Price	Average Net Cost ($/MWh)
Jan	33.0	$ 3.4	$ 1.9	$ 436,369	$ 102.03	$ 57.74
Feb	23.8	$ 2.5	$ 1.4	$ 225,168	$ 103.45	$ 60.62
Mar	13.5	$ 1.5	$ 0.9	$ 32,607	$ 111.38	$ 68.80
Apr	14.3	$ 2.2	$ 1.6	$ 30,945	$ 155.79	$ 109.06
May	27.1	$ 2.9	$ 1.4	$ 30,854	$ 105.43	$ 50.71
Jun	15.7	$ 1.9	$ 1.0	$ 129,924	$ 123.79	$ 64.45
Jul	28.6	$ 3.4	$ 1.9	$ 94,811	$ 118.76	$ 65.07
Aug	29.0	$ 2.7	$ 0.9	$ 105,756	$ 91.60	$ 30.82
Sep	18.1	$ 2.1	$ 1.2	$ 268,150	$ 113.03	$ 63.71
Oct	108.7	$ 9.4	$ 4.1	$ 191,202	$ 86.26	$ 37.65
Nov	30.6	$ 3.5	$ 1.9	$ 221,467	$ 113.78	$ 63.03
Dec	22.6	$ 3.9	$ 2.6	$ 416,144	$ 170.99	$ 115.47
2006 Total	**365.0**	**$ 39.2**	**$ 20.8**	**$ 2,183,396**	**$ 107.36**	**$ 56.89**

Table 6.5 Decremental OOS Congestion Costs in 2007

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Average Price	Average Net Cost ($/MWh)
Jan	(20.0)	$ (1.0)	$ 0.1	$ 49.67	$ 4.27
Feb	(25.6)	$ (1.5)	$ 0.2	$ 58.03	$ 6.12
Mar	(7.6)	$ (0.3)	$ 0.2	$ 45.91	$ 22.31
Apr	(0.7)	$ (0.0)	$ 0.0	$ 42.18	$ 14.09
May	(16.2)	$ (0.6)	$ 0.6	$ 39.45	$ 39.96
Jun	(7.3)	$ (0.4)	$ 0.1	$ 54.42	$ 19.21
Jul	(10.6)	$ (0.5)	$ 0.3	$ 51.65	$ 23.83
Aug	(5.7)	$ (0.2)	$ 0.4	$ 29.28	$ 67.63
Sep	(15.4)	$ (0.6)	$ 0.2	$ 42.04	$ 11.49
Oct	(165.1)	$ (7.1)	$ 4.4	$ 42.84	$ 26.44
Nov	(128.5)	$ (5.4)	$ 2.3	$ 41.80	$ 17.74
Dec	(78.1)	$ (4.0)	$ 1.1	$ 51.56	$ 13.51
2007 Total	**(480.8)**	**$ (21.7)**	**$ 9.7**	**$ 45.19**	**$ (20.22)**

The increase in OOS redispatch costs in 2007 over the 2006 level was due primarily to the increased need for management of local congestion in Humboldt County, a rural region in Northern California connected to the CAISO grid by two relatively small transmission lines. Until December 31, 2006, the Humboldt area was supported by RMR contracts covering the region's four generators, rated at a total of 135 MW. Beginning January 1, 2007, the CAISO managed reliability in this transmission-constrained region through OOS redispatches. Humboldt-area local OOS dispatches are typically in the incremental direction, while the dispatch in the remainder of the NP15 zone is generally decremental to manage over-scheduling in that region.

Of the $30.49 million in intra-zonal congestion redispatch costs, $14 million are due to uplifts to support local reliability in the Humboldt area.

Figure 6.9 Monthly Contribution to Intra-Zonal Congestion OOS Redispatch Costs by Reason in 2007