SWIDLER BERLIN SHEREFF FRIEDMAN, LLP

THE WASHINGTON HARBOUR
3000 K STREET, NW, SUITE 300
WASHINGTON, DC 20007-5116
TELEPHONE (202) 424-7500
FACSIMILE
WWW.SWIDLAW.COM

JULIA MOORE
DIRECT DIAL: (202) 295-8357
FAX: (202) 424-7643
JULIAMOORE@SWIDLAW.COM

NEW YORK OFFICE
THE CHRYSLER BUILDING
405 LEXINGTON AVENUE
NEW YORK, NY 10174
TEL.(212) 973-0111
FAX (212) 891-9598

October 26, 2004

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***California Independent System Operator Corporation***
Docket No. ER04-835-000

Pacific Gas and Electric Company v. California Independent System Operator Corporation
Docket No. EL04-103 (consolidated)

Dear Secretary Salas:

Enclosed please find an original and 7 copies of the Revised Direct Testimony and Exhibits of Brian D. Theaker on behalf of the California Independent System Operator Corporation. Two additional copies of this filing are enclosed to be stamped with the date and time of filing and returned to our messenger. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

Julia Moore

Counsel for the California Independent System Operator Corporation

Cc: The Honorable H. Peter Young
Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	Docket No. ER04-835-000
	)	
Pacific Gas and Electric Company	)	
	)	
v.	)	Docket No. EL04-103-000
	)	
California Independent System Operator Corporation	)	(Consolidated)

SUMMARY OF
REVISED DIRECT TESTIMONY OF
BRIAN D. THEAKER
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Mr. Theaker is Director of Regulatory affairs for the ISO. He testifies regarding five primary areas: the current allocation of costs (Start-Up Costs, Emissions Costs, and Minimum Load Costs) incurred to comply with the must-offer obligation, the process the ISO undertook to modify aspects of the must-offer process, including the allocation of must-offer costs, the ISO's proposal to allocate must-offer costs, when the ISO proposes to make the revised cost allocation effective, and issues surrounding the need to file revised testimony.

Currently, all Start-Up Costs and Emissions Costs incurred to comply with the must-offer obligation are invoiced to the ISO and allocated to ISO Control Area Demand and to exports to other in-state Control Areas. Minimum Load Costs are invoiced directly to Market Participants on a monthly basis.

Mr. Theaker explains the ISO's proposal for allocating must-offer costs contained in Amendment No. 60 to its Tariff. The ISO proposed to separate Minimum Load Costs into three categories (for local reliability reasons, for Zonal requirements, and for system requirements), each entailing a different allocation methodology based on cost-causation principles.

Mr. Theaker describe how, although the ISO proposed to make the revised cost allocation effective October 1, 2004, the ISO has determined that it will accept the refund effective date of July 17, 2004, established by the Commission in its July 8, 2004 order in Docket No. EL04-103-000. Once the Commission has finally determined the allocation of Minimum Load Costs in this proceeding, the ISO will "re-run" its market settlements and retroactively adjust Minimum Load Cost Charges back to July 17, 2004 to reflect that final determination.

Mr. Theaker testifies that the ISO is making a revised filing of his testimony and exhibits due to a problem with the historical data on which some of the previous document were based. Mr. Theaker explains that Exhibit Nos. ISO-5 and ISO-8 through 11 will be again updated when additional data for 2004 is available.

EXHIBIT NO. ISO-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator) Corporation) Docket No. ER04-835-000
)
Pacific Gas and Electric Company) Docket No. EL04-103
v.)
California Independent System Operator) Corporation) (consolidated)

REVISED DIRECT TESTIMONY OF BRIAN D. THEAKER

ON BEHALF OF THE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Brian D. Theaker. My address is 151 Blue Ravine Road, Folsom, California 95630.

Q. WHERE ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the California Independent System Operator Corporation (the "ISO") as the Director of Regulatory Affairs.

Q. PLEASE GIVE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelors of Science degree in Electrical Engineering from the Ohio State University in 1983, and a Masters in Business Administration degree from Pepperdine University in 1989. I worked as a high voltage laboratory and field test engineer in the Research Group of the Testing Laboratories of the Los Angeles Department of Water and Power ("LADWP") from 1983 to 1986. In 1986, I transferred to the Security Assessment Group at LADWP's Energy Control Center, where I worked in system operations, performing power flows, conducting security analysis of High Voltage Direct Current transmission systems, and preparing power system disturbance reports. In 1997, I joined the California Independent System Operator as an Operations Engineer at the ISO's back-up site in Alhambra, California. During this time, I was the ISO's lead representative in negotiating Reliability Must-Run ("RMR") Contracts. I moved to the ISO's primary operations site, Folsom, California in January 1999 and became the Manager of Operations Engineering in March 1999. Because my primary duties still centered on the RMR Contracts, in January 2000, I became the Manager of Reliability Contracts. In May 2001, I became the Director of Regulatory Affairs. My job responsibilities as Director of Regulatory Affairs include working with the ISO's Senior Regulatory Counsel to oversee Federal and state regulatory communications and working with others in the ISO to interpret and, when necessary, propose revisions to the ISO Tariff.

Q. HAVE YOU HAD SPECIFIC RESPONSIBILITIES AT THE ISO IN CONNECTION WITH AMENDMENT NO. 60 AND THE COST ALLOCATION PROPOSAL?

A. On behalf of the ISO, I convened and organized the stakeholder process that began in September 2003 to review the ISO's implementation of the Commission-imposed must-offer obligation. I was the ISO's lead representative in that stakeholder process that culminated in the filing of Amendment No. 60 to the ISO Tariff on May 8, 2004.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes. I provided testimony used in two separate hearings in Dockets Nos. ER98-495, ER98-496, *et al.* in March and April 2000. These hearings were held to determine the appropriate level of fixed cost recovery for RMR Units. My testimony was on a computer model I developed to forecast annual operating revenues for RMR units based on market prices for electricity and Ancillary Services in the California Power Exchange and ISO markets.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will cover four primary areas. First, I will describe the current allocation of must-offer costs. Second, I will describe the process the ISO undertook to modify aspects of the must-offer process, including the allocation of must-offer costs. Third, I will summarize the ISO's proposal to allocate must-offer costs. Fourth, I will discuss when the ISO proposes to make the revised cost allocation effective. Finally, I will explain the issues related to the need for filing this Revised Testimony.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. I will be using terms defined in the Master Definitions Supplement, Appendix A of the ISO Tariff.

Q. **WHY IS THE ISO FILING REVISED TESTIMONY?**

A. In preparing support for Amendment No. 60, staff from the ISO's Department of Market Analysis ("DMA") reviewed the reasons given for must-offer wavier denials in operations logs from January 2003 through May 2004. DMA staff classified these costs as "local", "zonal", or "system" based on their interpretations of the operations logs. DMA staff then calculated how these costs would be allocated based on this classification. In response to data requests in this proceeding, the ISO reviewed DMA staff's initial classification of Minimum Load Costs with operations staff. Based on this review, the ISO determined that DMA's classification was in certain cases incorrect and, furthermore, that the logging data, which had not been collected for cost allocation purposes, were, in many cases, vague, incomplete or inaccurate. The ISO is filing revised testimony to eliminate this incorrect data.

In addition, at the discovery and scheduling conference held in this proceeding on October 5, 2004 to discuss the data error, the ISO committed to filing additional information in its revised testimony concerning: (1) its proposed methodology for classifying costs as system, zonal, or local and (2) the process by which the ISO would propose to calculate the "incremental" cost associated with zonal dispatch prior to the implementation of the ISO's security constrained unit commitment process.

Q. **IS THE ISO MAKING ANY CHANGES TO ITS PREVIOUSLY-FILED EXHIBITS?**

A. Yes. The ISO is providing revised versions of Exhibit No. ISO-5 and Exhibit Nos. ISO-8 through ISO-11. The ISO is withdrawing Exhibit Nos. ISO-12 and ISO-13. To avoid confusion, we are re-filing all of the exhibits except 12 and 13. In addition, the revised exhibits are marked with today's date.

Q. **IS THE ISO REPLACING THIS DATA WITH CORRECTED DATA?**

A. Only in part. The ISO has concluded that historical data could not be relied upon as representative of the future need for Minimum Load Costs. For this reason, and because costs will not be re-allocated prior to July 17, 2004 (the refund effective date established by the Commission's July 8, 2004 order in Dockets EL04-103 and ER04-835 (*Pacific Gas and Electric Company v. California Independent System Operator Corporation*, 108 FERC ¶ 61,017 (2004)), the ISO, in accordance with the agreement reached by the parties at the discovery and scheduling conference, is re-filing its testimony and exhibits to provide information on Minimum Load Costs incurred in June, July, and August 2004 only.

Q. **WHY DOES THE ISO BELIEVE THE HISTORICAL DATA CANNOT BE RELIED ON AS REPRESENTATIVE OF FUTURE MINIMUM LOAD COSTS?**

A. Transmission upgrades will reduce or eliminate many of the constraints for which the ISO denied must-offer waivers in 2004. First, the Path 15 upgrade is expected to be complete in December 2004. This upgrade will increase the ability to transfer power between Northern and Southern California, and will reduce the need to commit additional generation in either NP15 or SP15 to ensure there is sufficient generation within an area to meet the Demand in that area if transmission into that area is lost. Second, a third 230/220-kV transformer bank was added at Sylmar in October 2004, and work to re-configure the DC terminals at Sylmar to balance injections into the 230 kV and 220 kV AC systems from the DC system is expected to be complete in January 2005. Third, the rating of the South of Lugo path was increased from 4400 MW in early 2004 to 5100 in July 2004, and is expected to be further increased to 5700 MW in July 2005. This upgrade does not eliminate the need to commit Generating Units for this transmission path, but does change the nature of this constraint from a thermal overload to a voltage concern. As a result, the ISO expects that fewer units will be needed to maintain the reliability of this path in the future. Fourth, the rating of Path 26 will be increased from 3400 MW to 3700 MW in 2005. Fifth, a second 500/230 kV transformer bank is expected to be put in service at Miguel substation in November 2004, reducing congestion at that location. Finally, on July 8, 2004 the California Public Utilities Commission issued an order directing the California Investor Owned Utilities to consider local reliability problems in their procurement decision, which, if fully effective, will reduce the number of Generating Units the ISO must commit through must-offer waiver denials. Taken together, the ISO expects that that Generating Units will not be denied waivers for the problems discussed above, and the volume of must-offer waiver denials will be reduced in 2005.

BACKGROUND

Q. PLEASE DESCRIBE THE "MUST-OFFER" REQUIREMENT.

A. The must-offer obligation was instituted by order of the Commission in April 2001. The must-offer obligation requires all owners of non-hydro-electric Generating Units with Participating Generator Agreements to offer available capacity from those Generating Units to the ISO's real-time Imbalance Energy Market. To satisfy the must-offer obligation, Generating Units that cannot start up within the settlement time horizon of the real-time market (which currently settles on a ten-minute basis) must be operating at least at the Generating Unit's minimum operating level and bidding all available capacity above that minimum operating level into the ISO's real-time Imbalance Energy Market.

Q. ARE THERE ANY EXCEPTIONS TO THIS REQUIREMENT?

A. Yes. The ISO does not want or need every Generating Unit operating at its minimum operating level and bidding into the real-time Imbalance Energy Market when conditions do not require them to do so. In fact, having too many

Generating Units operating their minimum operating levels may contribute to Overgeneration in off-peak hours (between 10 PM and 6 AM, when demand for electricity is at its lowest point during the day). In such circumstances, the ISO may grant a waiver of the must-offer obligation so that a Generating Unit may be shut off. When the ISO requires a Generating Unit subject to the must-offer obligation that has been granted a waiver and is shut off to start up and operate, the ISO revokes that Generating Unit's waiver of the must-offer obligation and directs the Generating Unit to start up.

The Scheduling Coordinator for a Generating Unit subject to the must-offer obligation also may request a waiver of the must-offer obligation when it wants to shut that Generating Unit off. If the ISO does not grant the waiver, the Generating Unit must remain in operation and the ISO will pay the costs to operate the Generating Unit at its minimum operating level, including when the ISO dispatches Energy from the Generating Unit or the Generating Unit provides Ancillary Services. If the Generating Unit is providing Energy for a bilateral sale, it is not eligible to collect its Minimum Load Costs. If the ISO grants the waiver, the Generating Unit may shut down; if it does not shut down, the ISO is not obligated to pay its Minimum Load Costs even if the Generating Unit is not involved in a bilateral sale but only providing Uninstructed Imbalance Energy.

Q. WHAT TYPES OF COSTS ARE INCURRED UNDER THE MUST-OFFER OBLIGATION?

A. The ISO incurs three types of costs under the must-offer obligation: (1) costs associated with starting a Generating Unit; (2) Emissions Costs incurred while operating a Generating Unit in compliance with the must-offer obligation; and (3) the costs of operating a Generating Unit at its minimum operating level in compliance with the must-offer obligation.

The first type of costs, start-up costs, currently include (1) the cost of fuel consumed by the Generating Unit from the time the Generating Unit's fires are first lit (the time of "first fire") until the earlier of (a) the time the Generating Unit is synchronized to the grid or (b) the Generating Unit's start-up time as recorded in the ISO's Master File, and (2) the cost of auxiliary power (i.e., power used by the Generating Unit's support equipment, such as fans or pulverizers) used during the start-up. The ISO's Master File contains data on the operating characteristics of Generating Units that are subject to a Participating Generator Agreement with the ISO.

The second type of costs are the NOx mitigation fees actually incurred by

Generating Units when they are operating in compliance with the must-offer obligation.

The third type of costs, Minimum Load Costs, are the costs of the fuel consumed when the Generating Unit is operating at its minimum operating level at the ISO's direction in compliance with the must-offer obligation, plus a $6.00/MWh adder for variable operations and maintenance.

Q. PRIOR TO AMENDMENT NO. 60, HOW WERE THE COSTS ASSOCIATED WITH MUST-OFFER PAYMENTS DETERMINED, PAID, AND ALLOCATED BY THE ISO?

A. Start-up and emissions costs are determined and allocated the same way. First, each Generating Unit's Scheduling Coordinator directly invoices the ISO for Start-Up Costs and Emissions Costs incurred while complying with the must-offer obligation. The ISO then pays these invoices out of two separate trust accounts, one for Emissions Costs and one for Start-Up Costs. These trust accounts are funded through a per-MWh rate charged monthly to (1) all ISO Control Area Demand and (2) exports from the ISO Control Area to other Control Areas within California, such the Sacramento Municipal Utility District Control Area, in that month. All Start-Up Costs and Emissions Costs incurred to comply with the must-offer obligation are therefore allocated to ISO Control Area Demand and to exports to other in-state Control Areas on a monthly basis.

In contrast, Minimum Load Costs are not invoiced to the ISO but are calculated by the ISO as the sum of (1) the product of the Generating Unit's heat rate at its minimum operating level and an indexed gas price and (2) the product of a $6.00/MWh adder and the Generating Unit's minimum operating level. Minimum Load Costs are currently allocated to the same constituency as Start-Up Costs and Emissions Costs – monthly Demand within the ISO Control Area and monthly exports from the ISO Control Area to other Control Areas within California. Unlike Start-Up Costs and Emissions Costs, however, Minimum Load Costs are not paid out of a regularly funded trust fund account, but are invoiced directly to Market Participants on a monthly basis.

Q. WHAT HAS THE ISO BEEN PAYING FOR THESE MUST-OFFER COSTS?

A. Monthly must-offer costs dating back to the implementation of the must-offer obligation are shown in Exhibit Nos. ISO-2 through ISO-4. Monthly Start-Up Costs are shown in ISO-2. Monthly Emissions Costs are shown in ISO-3. Total Monthly Minimum Load Costs are shown in ISO-4.

Q. WHY DOES THE ISO NOW PROPOSE A DIFFERENT METHOD TO ALLOCATE MUST-OFFER COSTS?

A. During the must-offer stakeholder process, the ISO prepared information on which Generating Units were being committed and operated through the must-offer process and why those Generating Units were committed and operated. This information showed that significant portions of the must-offer costs were incurred in connection with Generating Units operating to address operating problems in a particular region or location within the ISO Control Area and not to provide Energy to meet overall system requirements. Additionally, most of these operational issues were occurring in Southern California, within the Congestion Zone known as SP15. Exhibit No. ISO-5 shows Minimum Load Costs for June, July and August 2004 categorized into "local" reliability, "Zonal" reliability and "system" reliability costs. For the purposes of ISO-5, "system" reliability costs are Minimum Load Costs from Generating Units committed and operating to meet projected Energy requirements within the entire ISO Control Area, not the Minimum Load Costs incurred to manage Congestion, maintain compliance with a regional nomogram, or meet a local reliability need. Zonal reliability costs are those costs associated with Sylmar, Path 15, Path 26, the SCIT nomogram, and Path 66 (the California-Oregon 500-kV Intertie).

Q. PLEASE DESCRIBE THE PROCESS THAT LED THE ISO TO CONSIDER REVISING THE COST ALLOCATION METHODOLOGY.

A. The ISO committed to re-examining the must-offer process at a September 3, 2003 technical conference on the use of Condition 2 RMR Units for system reliability requirements called by the Commission staff, in response to Market Participants' concerns that they did not understand how the ISO was determining which Generating Units to commit through the must-offer process. The ISO began by asking Market Participants to submit questions on the must-offer process. The discussion centered on the topics contained in the questions submitted, namely (1) how the ISO determines which Generating Units it requires to operate each day; (2) how much must-offer Generating Units are compensated and their eligibility for compensation; and (3) ways to eliminate the disincentives for must-offer Generating Units to participate in the ISO's Ancillary Services markets.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS UNDERTAKEN BY THE ISO.

A. The ISO held a conference call to gather questions and issues from Market Participants on September 24, 2003. The ISO hosted stakeholder meetings discussing must-offer issues in Folsom, California on October 8, 2003, October 27, 2003, November 19, 2003, January 16, 2004, and March 10, 2004. All materials discussed during the stakeholder process, including agendas for the meetings, meeting presentations, white papers on specific issues, data requested by stakeholders in the process, and stakeholder comments, were regularly posted to the ISO Home Page at http://www.caiso.com/docs/2002/05/02/2002050215450112004.html.

Q. DID THE ISO SOLICIT INPUT FROM MARKET PARTICIPANTS ON THE ISSUE OF THE MUST-OFFER COST ALLOCATION?

A. Yes. The ISO presented its initial proposal on how must-offer costs should be allocated in an issue matrix that was posted to the ISO Home Page on December 19, 2003. The URL for that matrix is http://www.caiso.com/docs/2003/12/19/2003121911505122956.doc. On the same day, December 19, 2003, the ISO sent a notice to all Market Participants seeking comments on the issue matrix. The salutation line of this e-mail was addressed to Market Participants involved in the must-offer stakeholder process, though the e-mail was sent to all ISO Market Participants. The ISO posted an updated version of that issue matrix populated with the responses it received from Market Participants on January 14, 2004. The URL for that revised issues matrix is http://www.caiso.com/docs/2004/01/13/200401131422364289.pdf. On

March 4, 2004, the ISO posted an agenda for a must-offer stakeholder meeting scheduled for March 10, 2004 indicating that must-offer cost allocation would be one of the topics to be discussed at that meeting. The presentation on must-offer cost allocation for that March 10, 2004 meeting is available on the ISO Home Page at http://www.caiso.com/docs/09003a6080/2e/6e/09003a60802e6e19.pdf. On April 26, 2004, the ISO posted a draft of Amendment No. 60, including attachments, on the ISO Home Page (at http://www.caiso.com/docs/2002/05/02/2002050215450112004.html), and e-mailed the same draft amendment to the participants in the must-offer stakeholder process, requesting their comments on the proposed amendment and attachments by May 3, 2004. The ISO subsequently tendered Amendment No. 60 for filing on May 11, 2004.

Q. HOW DID THE ISO ADDRESS THE VIEWS OF STAKEHOLDERS ON THE ISSUE OF COST ALLOCATION?

A. First, as the extensive use of must-offer Generating Units for reasons other than Control Area-wide requirements became evident, the ISO proposed to change the cost allocation methodology from a Control Area-wide allocation to a two-part allocation, with costs incurred for local reliability reasons allocated to the local

Participating Transmission Owner ("Participating TO") and Control Area-wide costs still allocated to Demand and in-state exports. As the stakeholder discussion progressed, the ISO proposed a third category for allocating Minimum Load Costs where such costs were attributable not to purely local reliability problems, but were more regional in nature, though not related to other Control Area requirements.

The Pacific Gas and Electric Company ("PG&E") submitted comments supporting the changes to the methodology for allocating Minimum Load Costs but expressing concern that the ISO did not intend to implement those changes until it implemented the Phase 1B modifications to its settlements systems. These modifications were implemented effective for the October 1, 2004 trade date. The ISO met with PG&E to discuss these concerns, but, for reasons described below, declined to try to advance the implementation date for the proposed revised cost allocation.

During the stakeholder process, Southern California Edison Company ("SCE") asserted that if a Generating Unit is committed and operated for a local reliability need, and that Generating Unit also helps meet Control Area-wide (*i.e.*, system) needs, the full cost of committing and allocating that Generating Unit should not be allocated to the Participating TO. SCE proposed that only the "incremental cost" of that Generating Unit – *i.e.*, the cost of committing and operating that particular Generating Unit above the cost of operating the least expensive Generating Unit that would have been committed and operated to meet the Control Area needs if there had been no local reliability requirement – be allocated to the Participating TO. The ISO determined it would be possible to calculate this incremental cost by a two-pass run of the Security Constrained Unit Commitment ("SCUC") application that will be used to determine which Generating Units will be committed under the must-offer obligation. The first pass will consider only system needs and commit Generating Units on a least-cost basis to meet those needs. The second pass will include those Generating Units needed for local reliability requirements as well as Control Area needs. The "incremental cost" between the second run and the first run represents the additional cost that must be incurred to commit particular Generating Units needed for local reliability instead of committing the least expensive Generating Unit available within the ISO Control Area. The ISO accepted SCE's suggestion and proposed in Amendment No. 60 that only the incremental Minimum Load Cost will be allocated to the Participating TO, while the remaining Minimum Load Cost will be classified as for system needs and allocated to Net Negative Uninstructed Deviation and, as necessary, Control Area Demand and in-state exports.

SCE also requested that the ISO modify its Tariff to classify the Minimum Load Costs it would be allocated when Generating Units are committed to address local reliability problems in its service area as Reliability Services Costs. The ISO agreed that such costs are incurred to provide for reliability and included a definition of Reliability Services Costs in Amendment No. 60.

Q. DID THE ISO RECEIVE THE APPROVAL OF ITS GOVERNING BOARD FOR THE PROPOSED REVISION TO THE COST ALLOCATION METHODOLOGY?

A. Yes. The ISO Governing Board approved the ISO's proposal to revise the Minimum Load Cost allocation at its meeting on March 25, 2004.

THE ISO PROPOSAL

Q. PLEASE DESCRIBE THE ISO'S PROPOSED AMENDMENT NO. 60

A. Amendment No. 60 proposed to modify the ISO Tariff to:

1. Use a Security Constrained Unit Commitment application to evaluate requests for waiver of the must-offer obligation to minimize must-offer commitment and operating costs to replace the former system of granting waivers on a "first come, first served" basis;

2. Revise the indexed gas cost used to calculate Minimum Load Costs to include intra-state gas transportation charges and other fees and to use location-specific daily, rather than state-wide monthly, fuel indices;
3. Include auxiliary power as a recoverable Start-Up Cost;
4. Eliminate the former practice of rescinding Minimum Load Cost payments when a unit was providing Ancillary Services;
5. Revise the timing of the daily process for requesting, evaluating and granting waivers to facilitate Generating Units subject to the must-offer obligation participating in the Day-Ahead Ancillary Services markets;
6. Clarify Self-Commitment and eligibility for Minimum Load Cost payment;
7. Revise how Minimum Load Costs are allocated; and
8. Establish a framework for calling on Condition 2 RMR Units for system reliability requirements outside the RMR Contract.

Q. HOW DID AMENDMENT NO. 60 PROPOSE TO REVISE THE ALLOCATION OF MUST-OFFER COSTS?

A. The ISO did not propose to change the methodology for allocating Start-Up Costs and Emissions Costs. However, the ISO did propose to separate Minimum Load Costs into three categories based on the reason the Generating Unit was committed and operated under the must-offer obligation – (1) for local reliability reasons, (2) for Zonal requirements, and (3) for system (*i.e.*, Control Area-wide) requirements. The ISO proposed to allocate Minimum Load Costs for local reliability reasons to the Participating TO in whose service area the Generating Unit is located on a monthly basis. The ISO proposed to allocate Minimum Load Costs for Zonal reliability requirements to total monthly Demand within the affected Zone. The ISO proposed to allocate Minimum Load Costs for system reliability requirements first to monthly Net Negative Uninstructed Deviations up to a capped $/MWh rate. That capped rate is determined by dividing the total monthly Minimum Load Costs by the total monthly MWh produced by Generating Units operating at their minimum operating levels in accordance with the must-offer obligation. Any costs in excess of this capped $/MWh rate are then allocated to monthly Demand and monthly in-state exports. The Tariff sheets implementing these changes are provided as Exhibit No. ISO-6. The blackline text showing how the revisions modified the existing provision is provided as Exhibit No. ISO-7.

Q. WHY DIDN'T THE ISO PROPOSE TO CHANGE THE ALLOCATION OF START-UP AND EMISSIONS COSTS?

A. The ISO did not propose to change the allocation of those costs because those costs were small relative to the amount of Minimum Load Costs, and creating and maintaining a complex system to track and allocate those costs was not viewed as an efficient use of ISO staff resources. For the last 12 months for which the ISO has submitted invoices, Emissions Costs were $2.05 million and Start-up Costs were $1.79 million, for a total of $3.84 million. In contrast, Minimum Load Costs for calendar year 2003 were $125 million.

Q. HOW DOES THE ISO DISTINGUISH BETWEEN LOCAL RELIABILITY COSTS AND ZONAL COSTS?

A. In the criteria that the ISO filed as an Attachment E to its Amendment No. 60 filing, the ISO indicated that the costs of Generating Units committed and operated under the must-offer obligation would be considered local and allocated to the Participating TO if the Generating Unit were managing flows on a transmission line not considered to be an Inter-Zonal Interface. Inter-Zonal Interfaces are (1) the transmission paths between the three existing ISO Congestion Zones – NP15, ZP26, and SP15, and (2) the transmission paths between the ISO Control Area and other Control Areas. Under the ISO's current Congestion Management model, all Generating Units within a Congestion Zone are considered to be equally effective at managing flows on the Inter-Zonal Interface.

Upon further consideration, the ISO believes that there currently are three constraints for which the ISO operates Generating Units under the must-offer obligation that should be classified as Zonal constraints and whose Minimum Load Costs should be allocated Zonally beyond constraints that are Inter-Zonal Interfaces: (1) the 500/230 kV transformer bank at Miguel Substation in SP15; (2) the South-Of-Lugo transmission path in Southern California; and (3) the Southern California Import Transmission ("SCIT") nomogram. The Miguel constraint and the South-Of-Lugo constraint would currently be classified as Intra-Zonal constraints, but, as described below, involve transmission paths that provide more regional benefit. Though the ISO did not mention the SCIT nomogram expressly in Attachment E to Amendment No. 60, the ISO indicated it would classify as Zonal any Minimum Load Costs for a unit committed or operated to "maintain operations within the requirements of any nomogram that governs the operations of [an] inter-zonal transmission path(s)." This change does not require a revision to Amendment No. 60 itself. If, however, the Commission were to require that the criteria included as Attachment E be included as part of the ISO Tariff, Attachment E would require revision.

Q. WHAT IS THE MIGUEL CONSTRAINT?

A. Miguel substation is the western terminus of the 500-kV Southwest Power Link, which brings power into Southern California from Arizona and Northern Mexico. In recent months, the 500/230-kV transformer bank at Miguel was routinely loaded at or above its rating. Several factors contribute to the overloads on the 500/230 kV transformer bank at Miguel: (1) the recent addition of several thousand MW of newer, efficient generation in western Arizona and in northern Mexico which is imported into Southern California to serve Load there and elsewhere in California; (2) any power imported into Southern California from the Palo Verde scheduling point, not just that from the newer generation, comes into California both on the Palo Verde – Devers 500-kV line and on the Southwest Power Link.

Q. WHAT IS THE SCIT NOMOGRAM?

A. The SCIT nomogram prescribes a simultaneous limit on the amount of power than can simultaneously be imported into Southern California over five transmission paths and the East-Of-River transmission system bringing power from Arizona and Nevada into Southern California based on the amount of generating inertia on-line in Southern California. The five paths monitored in the SCIT nomogram are (1) Path 26 (the three 500-kV lines connecting Central and Southern California); (2) The West-Of-River transmission system, which comprises several 500-kV circuits bringing power into California from Arizona and Nevada; (3) the Intermountain-Adelanto High Voltage Direct Current Southern Transmission System, bringing power directly into Southern California from Utah; (4) the North-of-Lugo transmission system; and (5) the 500-kV Pacific Direct Current Intertie, bringing power directly into Southern California from the Pacific Northwest.

Q. WHAT IS THE SOUTH-OF-LUGO RESTRICTION?

A. The South-Of-Lugo path is made up of three 500-kV circuits from Lugo substation to the south: the Lugo–Serrano 500 kV Line 1, the Lugo–Mira Loma 500-kV Line 2, and the Lugo–Mira Loma 500-kV Line 3. Two sets of inter-regional transmission paths meet at Lugo Substation. Lugo Substation is both the western terminus of 500-kV lines bringing power in from the east and the eastern/southern terminus of 500-kV lines bringing power in from the north. Power then flows into Southern California on these three circuits. The South-Of-Lugo path was upgraded from a rating of 4400 MW to 4800 MW on May 27, 2004, and from 4800 MW to 5100 MW on July 29, 2004.

Q. WHY DOES THE ISO BELIEVE MINIMUM LOAD COSTS ASSOCIATED WITH THE CONSTRAINTS SHOULD BE ALLOCATED ZONALLY?

A. The network facilities affected by these constraints both bring power into the

SP15 Zone and transfer power between Participating TO service areas within the SP15 Zone. These network facilities are not primarily involved with bringing power into one particular Participating TO's Load center.

The ISO proposes to allocate these costs Zonally because that cost allocation methodology replicates how the costs of re-dispatching Generation to manage Intra-Zonal Congestion are currently allocated under Section 7.3.2 of the ISO Tariff. This allocation methodology is appropriate for constraints that cannot be attributed to a Particular TO. It holds that parties within the Zone contribute to the need for the must-offer Generating Unit based on their Demand within the Zone.

Q. PLEASE SUMMARIZE HOW THE ISO DETERMINES WHICH COSTS SHOULD BE CLASSIFIED AS LOCAL AND WHICH SHOULD BE CLASSIFIED AS ZONAL.

A. Minimum Load Costs incurred (1) to maintain the reliability of Inter-Zonal Interfaces or transmission paths that carry power that benefits the customers of more than one Participating Transmission Owner or (2) to provide sufficient generating capacity within an import-constrained area that contains more than one Participating TO to serve the Demand in that area in the event transmission serving that area is lost should be classified as "Zonal". Minimum Load Costs incurred to address any other Intra-Zonal transmission problem should be classified as "local". The only Intra-Zonal constraints that the ISO currently considers should be classified as "Zonal" constraints are the Miguel constraint and the South-Of-Lugo constraint.

Q. WHY DOES THE ISO PROPOSE TO ALLOCATE LOCAL RELIABILITY COSTS TO THE PARTICIPATING TO?

A. Allocating local reliability costs to the Participating TO matches the methodology for allocating RMR costs. As set forth in Section 5.2.8 of the ISO Tariff, the costs associated with RMR Units, which the ISO also dispatches to meet local reliability requirements, are allocated to the Participating TO.

Q. WHY DID THE ISO PROPOSE TO ALLOCATE MINIMUM LOAD COSTS FOR SYSTEM RELIABILITY TO NET NEGATIVE UNINSTRUCTED DEVIATION?

A. The ISO commits and operates a Generating Unit under the must-offer obligation for system requirements when the ISO expects Demand in the Control Area will exceed the Supply (Generating Units and Energy imported into the Control Area) that Scheduling Coordinators have Scheduled in advance of real-time operations. Net Negative Uninstructed Deviation, which is made up of Demand that appears in real-time that was not Scheduled in the forward markets, Interchange that was Scheduled in the forward markets but did not appear in real-time, and Generation that was Scheduled in the forward markets but did not appear in real-time, represents the amount of amount of Energy the ISO must come up with in real-time to keep Demand and Supply in balance. Because Scheduling Coordinators are effectively "buying" this amount of Energy to balance their portfolios in real-time, the amount of Net Negative Uninstructed Deviation a Scheduling Coordinator incurs is an appropriate quantity on which to allocate the costs of the ISO procuring the additional Supply needed to keep the ISO Control Area in balance.

Q. WHY DID THE ISO PROPOSE TO USE A CAPPED RATE TO ALLOCATE MINIMUM LOAD COSTS FOR SYSTEM RELIABILITY REQUIREMENTS?

A. Without using a capped rate, a small amount of Net Negative Uninstructed Deviation could incur a disproportionate and unreasonable amount of Minimum Load Costs. For example, the ISO could commit additional Generating Units if temperatures and electricity usage are projected to be very high – higher than the schedules submitted by Scheduling Coordinators. Such projections may not always materialize, however, due to unexpected changes in weather or other unanticipated events. This could leave the ISO will significant Minimum Load

Costs but with a relatively small amount of Net Negative Uninstructed Deviation to which to allocate those costs. Allocating Minimum Load Costs to Net Negative Uninstructed Deviation is reasonable and follows cost causation principles, but it is not appropriate to impose upon a Market Participant a disproportionate amount of costs relative to its deviations. The capped rate, which is determined by dividing the total monthly Minimum Load Costs by the total monthly MWh produced by Generating Units operating at their minimum operating levels in accordance with the must-offer obligation, serves as a proxy for what a reasonable per-MWh Minimum Load Cost would be. Allocating Minimum Load Costs above the capped rate to all Demand within the ISO Control Area and to in-state exports is reasonable, because it proportionally passes those excess costs to all parties placing a demand on the Supply within the ISO Control Area. In a perfect world, Scheduling Coordinators' load forecasts would always accurately predict their actual demand and the ISO would have no need to commit additional Generating Units. In a slightly less perfect world, the ISO's load forecast would always match actual Demand and the ISO would never commit Generating Units beyond what was required to match Demand with Supply and meet all reliability needs. In the real world, both the ISO and Scheduling Coordinators' load forecasts are sometimes wrong. The ISO commits additional Generating Units when it believes such Generating Units are needed to meet total ISO Control Area Demand. While the ISO tries to optimize Generating Unit commitment, its forecasts are not perfect. It is reasonable to socialize the excess Minimum Load Costs that result from over-commitment to all ISO Control Area Demand and in-state exports.

Q. ARE THE ISO'S PROPOSALS TO ALLOCATE MINIMUM LOAD COSTS BASED ON COST-CAUSATION PRINCIPLES?

A. Yes. Local reliability costs are allocated to the Participating TO because it is the entity best suited to upgrade the power delivery network to eliminate the bottlenecks that give rise to the need for operating specific Generating Units under the must-offer obligation, especially where those bottlenecks occur on the parts of the network primarily intended to bring power into areas with significant, often concentrated, load. Generating Units often must be operated out of economic merit order to prevent transmission components from overloading or to maintain voltage at specific locations within acceptable limits. The need to operate specific Generating Units to relieve overloads or maintain acceptable voltage levels can arise for several reasons. A line may become overloaded when the demand for the Energy being carried by that line exceeds a particular level. A line can also be overloaded when another line in that same area is taken out of service for maintenance or due to a forced outage. In these cases, the Participating TO's network is inadequate to accommodate the Energy that must flow across it to meet Demand under these conditions. Arguably, the overloads could be prevented by intentionally disconnecting Load or by never performing maintenance, but such drastic solutions are impractical. Allocating the costs of the Generating Units that must be operated to prevent the network from being overloaded under these circumstances serves as an incentive for the Participating TO to modify or upgrade its network to address these deficiencies. This is the same methodology that the Commission has approved for the allocation of the costs of RMR Units, which also serve local reliability needs.

Allocating costs to the Participating TO for local network problems is also the most practical approach. Power flow on the network is determined by three fundamentals: (1) where and how much Energy is being injected onto the network (*i.e.*, the location and size of the Generating Units on the grid); (2) the configuration and impedance of the power delivery network between the Generating Units and the Load being served; and (3) where and how much Energy is being "withdrawn" from the network (*i.e.*, the location and Demand of the Load). Where new Generating Units are added to the grid is usually determined by (1) available fuel supplies, such as water or plentiful, inexpensive natural gas; (2) access to electric transmission; and (3) other externalities, such as environmental restrictions. The location of Load on the grid is primarily determined by where people live and work. Given that Generating Units are going to locate based on their particular fundamental needs, and Load is also going to locate based on its own factors, the remedy that remains is for the Participating TO responsible for serving the Load within its area to build adequate transmission facilities to deliver the Energy from the Generating Units to the Load in their service areas. Alternatively, a Participating TO could build or contract with a Generating Unit located in its service area to serve as "substitute transmission", that is, to provide Energy that relieves overloads or maintains acceptable voltages levels and obviates the need to build additional transmission facilities to allow Energy to be delivered to meet the Demand in its service area. Generating Units committed and operating under the must-offer obligation to relieve overloads and maintain voltages at particular locations in the network are, in fact, serving as such "substitute transmission". It is therefore reasonable and rational to allocate the Minimum Load Costs of operating those Generating Units for that purpose to the Participating TO.

Some overloads, however, occur on Extra High Voltage transmission circuits whose primary purpose is to bring Energy from one region to another, not to deliver Energy to a local Load center. The Energy flowing on these circuits can come from many remote generation sources and ultimately be destined for use in the service area of more than one Participating TO. Within the ISO's current market design, the transmission paths between Congestion Zones is a reasonable place to define where these regional power transfers take place. Where Generating Units must be committed and operated to relieve overloads or maintain acceptable voltages on these paths, allocating those costs to one particular Participating Transmission Owner is not equitable. Amendment No. 60 therefore attempts to allocate those costs to the Demand that can be considered responsible for the overloads. In the case of Zonal needs, the ISO concluded that the most appropriate allocation would be the Zonal Demand.

Q. THE SACRAMENTO MUNICIPAL UTILITY DISTRICT ("SMUD") HAS ASSERTED THAT MINIMUM LOAD COSTS SHOULD NOT BE ALLOCATED TO WHEEL-THROUGH SCHEDULES. DOES THE ISO AGREE?

A. No. According to the ISO's Amendment No. 60 proposal to allocate Minimum Load Costs, Minimum Load Costs would only be allocated to wheel-through schedules to the extent (1) the ISO was incurring Minimum Load Costs for System reasons, (2) there were excess Minimum Load Cost beyond those costs allocated to Net Negative Uninstructed Deviation, and (3) the wheel-through schedules were for exported energy from the ISO Control Area to another

Control Area in California. The Commission originally directed the ISO to charge Minimum Load Costs to in-state exports, and, while the ISO did propose to create new Zonal and Local classifications and to use Net Negative Uninstructed Deviation as the primary method for allocating System Minimum Load Costs, the ISO proposed to maintain the Commission's directed allocation for those System Minimum Load Costs not allocated to Net Negative Uninstructed Deviation. Both a wheel-through Schedule and a wheel-out Schedule may have in common an export from the ISO Control Area to another Control Area in California (the wheel-through transaction comes into the ISO Control Area from another Control Area, while the wheel-out transaction originates from a Generating Unit in California). The Commission did not distinguish between these two types of transactions when directing the ISO to allocate Minimum Load Costs to exports from the ISO Control Area to other Control Areas in California, and so the ISO did not propose to distinguish between these two types of transactions, either. The ISO proposed to allocate Zonal Minimum Load Costs to Demand in the constrained Zone, and did not propose to allocate Zonal Minimum Load Costs to wheel-through schedules.

Q. THE CALIFORNIA DEPARTMENT OF WATER RESOURCES NOTED IN THEIR PROTEST OF AMENDMENT NO. 60 THAT MINIMUM LOAD COSTS

SHOULD BE ALLOCATED TO THE FOLLOWING DAY'S PEAK DEMAND, NOT TO MONTHLY TOTAL DEMAND. IS THE NEED TO CALL UPON MUST OFFER RESOURCES PRIMARILY AN ON-PEAK PHENOMENON?

A. Yes. With the exception of Minimum Load Costs attributable to managing flows across the 230/220 kV transformer banks at Sylmar, most Minimum Load Costs are incurred during off-peak hours only because, due to Generating Unit minimum run time requirements, it is not possible to shut the unit off for the off-peak hours and turn it on again when it is required during the on-peak hours. Typically, the ISO does not require Generating Units committed under the must-offer obligation to be operating during the off-peak hours to meet reliability requirements. During 2004, Sylmar was the exception to this general rule, because the ISO required Generating Units to help manage off-peak as well as on-peak flows across the 230/220 kV transformer banks there. Though significant Minimum Load Costs were incurred in 2004 to support the reconfiguration and upgrade work at Sylmar, the ISO expects that Sylmar will not require the extensive use of must-offer resources in 2005 after the third 230/2330 kV bank is placed in service there and the DC terminals upgraded and reconfigured, barring unforeseen outages. While it is always possible that, due to an outage, some kind of problem that requires use of must-offer resources during the off-peak hours may emerge, in general, the ISO uses must-offer resources to meet on-peak needs and only holds the resources on across the off-peak hours because it is not physically possible to shut the units down and restart them for the next day's on-peak requirements.

Q. AMENDMENT NO. 60 ALLOCATES MINIMUM LOAD COSTS ON A MONTHLY BASIS. HAS THE ISO ACKNOWLEDGED THAT ALLOCATING COSTS ON OTHER PERIODS WOULD BE REASONABLE?

A. Yes. The ISO indicated it would be willing to allocate Minimum Load Costs on a daily basis in its answer to protests of Amendment No. 60. The Commission did not direct the ISO to do so in its July 8, 2004 order on Amendment No. 60, but instead directed the ISO to implement what it originally proposed in Amendment No. 60 effective on October 1, 2004, and set the matter of allocating Minimum Load Costs for hearing.

Q. DOES THE ISO'S LOGGING SYSTEM AND PRACTICES SUPPORT THE ISO'S PROPOSED ALLOCATION?

A. Yes. The ISO has improved its logging system, SLIC (which stands for Scheduling and Logging for ISO of California), to provide grid operators with a better way to capture the reason for committing and operating must-offer Generating Units. Since November 2003, ISO Grid Operations staff has made additional efforts to capture information that would allow the ISO to categorize and allocate the Minimum Load Costs from these Generating Units according to its proposal. The ISO also modified the software tool it uses to track Minimum Load Costs effective July 17, 2004, to track the system, Zonal or local allocation of those costs. The ISO tracks this information in addition to tracking the specific operating reason for committing the Generating Unit in the SLIC logs.

Q. HAS THE ISO INCLUDED ITS PROPOSAL TO CHARGE ONLY THE "NET INCREMENTAL COST" TO THE PARTICIPATING TO?

A. Yes. Originally, the ISO had proposed to implement the revised cost allocation methodology in Amendment 60 coincident with implementation of SCUC in Phase 1B of the ISO's Market Redesign and Technology Upgrade project ("MRTU"). However, as I will discuss later, the ISO has agreed to implement the revised methodology in accordance with the refund effective date set by the Commission in response to PG&E's complaint. I will explain later how the ISO proposes to implement the incremental cost methodology for the period from July until October 2004 when Phase 1B, including SCUC, was implemented.

While the ISO has proposed to include charging the net incremental cost back to July 17, 2004, the ISO has not fully replicated the methodology proposed to make that calculation in the software systems used to prepare this testimony and exhibits. Consequently, the exhibits presented with this testimony do not include the "net incremental cost" methodology.

ISSUES RELATED TO THE EFFECTIVE DATE AND IMPLEMENTATION

Q. WHAT EFFECTIVE DATE DID THE ISO REQUEST FOR THE REVISED COST ALLOCATION METHODOLOGY IN AMENDMENT NO. 60?

A. The ISO requested an effective date of October 1, 2004.

Q. WHY DID THE ISO REQUEST THIS DATE?

A. The ISO proposed to wait until that date to implement the revised cost allocation because the ISO is currently involved in modifying its settlements systems to incorporate changes required by Phase 1B of its market redesign. Phase 1B includes: (1) implementing a new single-price real-time economic dispatch system to replace the Balancing Energy Ex Post pricing ("BEEP") real-time dispatch software that has been in service since the ISO began operations on March 31, 1998. The ISO proposed to wait until the Phase 1B modifications were in place because it would be an undue burden, as well as threaten the scheduled implementation of the Phase 1B systems, to simultaneously incorporate the settlements modifications needed to implement the revised allocation of Minimum Load Costs into the existing settlements system software (which would be scrapped when the Phase 1B systems were put in service) and also incorporate the same cost-allocation related settlements modifications into the new Phase 1B settlements system software with the staff resources available to the ISO to make such changes. ISO staff investigated changing the settlements system to re-allocate the Minimum Load Costs through interim patchwork modifications to the settlements system (*e.g.*, assuming that some static percentage of Minimum Load Costs could be attributed to needs in SP15). Because the ISO follows a rigorous Software Development Life Cycle process for making system software changes, the ISO estimated it could not make any such "patchwork" changes any faster than it could implement the revised cost allocation as part of the Phase 1B implementation. Ultimately, the ISO concluded that implementing a patchwork reallocation would neither accelerate implementation of the new cost allocation methodology nor provide reasonable assurance that actual costs were being allocated in a rational way.

Q. DID ANY PARTY OR PARTIES PROTEST THIS DATE?

A. Yes. As indicated above, PG&E expressed concern about this proposed date in comments submitted to the ISO on the draft Amendment No. 60 filing, in its protest of Amendment No. 60, and in the May 18, 2004 complaint it filed against the ISO under Section 206 of the Federal Power Act.

Q. HAS THE ISO RECONSIDERED ITS POSITION ON THIS ISSUE?

A. Yes. As I stated before the ISO investigated options to accelerate implementing the cost allocation, but ultimately determined that rushing the implementation of the revised cost allocation would affect the implementation of Phase 1B.

The ISO requests that the presiding Administrative Law Judge accept PG&E's recommendation regarding the refund effective date of July 17, 2004, established by the Commission in its July 8, 2004 order in Docket No. EL04-103. Once the Commission has finally determined the allocation of Minimum Load Costs in this proceeding, the ISO will "re-run" its market settlements and retroactively adjust Minimum Load Cost charges back to July 17, 2004 to reflect that final determination.

Q. **HOW DOES THE ISO PROPOSE TO DETERMINE THE INCREMENTAL COST PRIOR TO IMPLEMENTATION OF SCUC IN PHASE 1B?**

A. By using the following process:

1. The ISO will first determine which units were committed through the must-

offer waiver denial process on a given day by querying the operations records. This information will also indicate what specific reason the unit was committed and, therefore, whether the Minimum Load Costs should be classified as local, Zonal or system costs.

2. Next, the ISO will capture the operating conditions (generation schedules, Ancillary Service Schedules, intertie Schedules, Path 15 and Path 26 limits, Demand forecasts, and fuel prices) for that day, either by (a) retrieving the SCUC save case, which contains all that information, or by (b) retrieving the information from other databases, including the Scheduling Infrastructure ("SI") database. Because the SCUC was not put into service until September 2, 2004, for trade date September 3, 2004, the ISO will have to use method (b) to re-create operating conditions from July 17, 2004 through September 2, 2004.

3. The ISO will run the SCUC for that day with the units committed for system and Zonal reasons forced on, and with the units that were actually committed for local reasons de-committed but available to be committed for the purposes of the SCUC run. If some of the units that were required for system and Zonal reasons had been committed for local reasons, then SCUC will re-commit those units when it performs this run. This run will provide the Minimum Load Costs for those units that operated for system and Zonal

reasons. For the period before SCUC was put in service on September 2, 2004, the calculation of system and Zonal Costs will reflect the ISO's "first come, first-served" process for committing Generating Units under the must-offer obligation. Consequently, the system and Zonal costs for those units expressly committed by the ISO for system and Zonal purposes and forced on in SCUC will not likely be the optimal level of costs to meet these classes of needs, but will reflect what actually occurred. After September 2, 2004, the SCUC commitment for system and Zonal reasons should be the optimal cost, so when SCUC is re-run to determine the net incremental cost, the system and Zonal costs determined for this period should be the same as those originally determined by SCUC when it initially determined which must-offer units to commit to meet the system and Zonal requirements.

Note that it is possible that the units that SCUC determines should have been committed to meet system and Zonal requirements are not the units that are actually committed. This can occur when the units committed to meet the local requirement displace those units that SCUC determined would be the optimal way to meet the system and Zonal requirements. Consider the following example. The least-cost commitment to meet system and Zonal needs is units A and B, for a total of 400 MW, at a cost of $1000. However, the ISO requires units C, D, E and F to be on for local requirements, for a total of 800 MW at a cost of $3000. If units C, D, E and F also meet the system and Zonal requirements, the ISO will not commit units A and B. However, for the purposes of calculating the incremental cost, the least-cost dispatch that would have met the system and Zonal requirements would have been A and B. The incremental cost will be calculated as $3000 - $1000 = $2000, even though units A and B were never committed.

4. Using the list of units that was actually operating that day for all reasons, the ISO will again "run" SCUC to calculate the actual Minimum Load Costs for all units for all reasons. In this mode, SCUC is not modifying the commitment but only calculating the cost.
5. By subtracting the Minimum Load Costs from the results of the run described in Step 3 from the Minimum Load Costs of the run described in Step 4, the ISO will determine the additional Minimum Load Cost of Generating Units that were committed to meet local need above the Minimum Load Costs of those units committed only to meet system and Zonal needs. This is the "incremental cost" that will be allocated to the Participating TOs in whose service area the units were located. System and Zonal costs will be allocated as described earlier.

In the case in which there was no system or Zonal requirement, all Minimum Load Costs will be "incremental" and allocated to the appropriate Participating TO. In the case in which there was no local requirement, there would be no incremental cost allocated to any Participating TO.

ISSUES RELATED TO THE NEED FOR REVISED TESTIMONY

Q. YOU INDICATED EARLIER THAT THE ISO DISCOVERED MANY PROBLEMS WITH THE OPERATIONAL LOG DATA WHEN IT REVIEWED THE OPERATIONS LOGS TO CHECK THE CLASSIFICATION OF COSTS AS "ZONAL" IN 2003, INCLUDING "VAGUE, INCOMPLETE OR INACCURATE" DATA. WOULD YOU PLEASE ELABORATE ON THE VAGUE DATA?

A. The ISO discovered that during 2003 only one 500/220 transformer bank was in service at Vincent substation following a fire there in March 2003.During this time, the ISO placed a temporary limit on Path 26 flow to ensure the transformer bank – which, like Path 26, essentially carried power between Northern California and Southern California – would not be overloaded. The reason given for denying must-offer waiver units needed to ensure the remaining 500/220 kV bank did not exceed its rating was "Path 26". Thus, in DMA's review of the logs, the reason for the must-offer waiver denial would be classified as for "Zonal". In

Attachment E to Amendment No. 60, however, the ISO had proposed to classify as "local" those Minimum Load Costs related to network equipment – like the 500/220 kV banks at Vincent – that are not part of a designated Inter-Zonal Interface.

Another example involves the ISO logs indicating that units were committed for "SP15 Capacity" or "NP15 capacity". While DMA's classification of these events would have appropriately classified these must-offer waiver denials as "Zonal", ISO operations staff indicate that units committed for these reasons were not committed to manage real-time flows between these zones, but to ensure sufficient generating capacity was available in a Zone or area to serve the load in that area if transmission bringing power into that Zone or area was lost.

Q. PLEASE PROVIDE EXAMPLES OF INCOMPLETE DATA.

A. The ISO discovered that in some cases there was no reason given for the must-offer denial, or that the reason given was "unknown". When DMA staff reviewed the logs, they included these costs in the "system" category.

Q. WHAT TYPES OF INACCURATE DATA DID YOU ENCOUNTER?

A. The ISO discovered that the reason given for denying waivers for some Southern

California Generating Units was "COI" – the California Oregon Intertie. CAISO Operations personnel agree that it is highly unlikely that the ISO would ever commit Southern California Generating Units to address operational problems on COI.

Q. HAS THE ISO CALCULATED HOW MINIMUM LOAD COSTS WOULD BE ALLOCATED USING THE CORRECTED DATA AND ACCORDING TO THE ALTERNATIVE ALLOCATIONS YOU HAVE DISCUSSED ABOVE?

A. Yes. The ISO has calculated how Minimum Load Costs would be allocated for June, July and August 2004 based on corrected logging and classification data. This data is presented as Exhibit No. ISO-8. In this exhibit, Minimum Load Costs are allocated on a monthly basis as proposed in Amendment No. 60. Furthermore, Minimum Load Costs are categorized as "Zonal" costs if the Generating Unit was committed and operated under the must-offer obligation to (1) mitigate congestion on an Inter-Zonal boundary, including at Sylmar, Path 15, Path 26 and the COI; (2) provide sufficient generating capacity to meet projected Demand within the constrained Zone if transmission carrying Energy into that Zone was lost; or (3) the Generating Unit was committed and operated under the must-offer obligation to maintain operations within the SCIT nomogram. Exhibit No. ISO-8 also indicates how "Zonal" costs for June, July and August 2004 are broken down by constraint.

In Exhibit No. ISO-9, the ISO, using the same corrected classification data, has calculated the allocation on a daily basis.

In Exhibit No. ISO-10, the ISO, using the same corrected classification data, has allocated all system and Zonal Minimum Load Costs incurred in the month to the sum of Demand or Net Negative Uninstructed Deviation, as the case may be, between 0600-2159 hours during the month. In other words, the ISO has allocated all Minimum Load Costs to monthly on-peak Demand or monthly on-peak Net Negative Uninstructed Deviation.

In Exhibit No. ISO-11, the ISO, again using the same corrected classification data, has allocated all system and Zonal Minimum Load Costs incurred each day to the sum of Demand or Net Negative Uninstructed Deviation, as the case may be, between 0600-2159 hours during that day. In other words, the ISO has allocated all daily Minimum Load Costs to daily on-peak Demand or daily on-peak Net Negative Uninstructed Deviation.

Q. **FOR WHAT REASONS DOES THE ISO ANTICIPATE COMMITTING**

GENERATING UNITS BY MUST-OFFER WAIVER DENIALS IN 2005?

A. Unless more Southern California Generating Units contract with, and are Scheduled by, Southern California Load Serving Entities to meet both the peak Demand requirements and local reliability requirements in 2005, the ISO still expects to commit Southern California Generating Units to meet the requirements of the SCIT nomogram. In addition, even though the South-Of-Lugo path has been upgraded, and the likelihood for exceeding the thermal rating of that path is reduced, the potential for voltage collapse has become a concern. The ISO has developed a new operating procedure that specifies minimum Generating Unit requirements for South-of-Lugo flows to address the voltage collapse concerns. Finally, the ISO expects to continue to use must-offer resources as necessary to meet Applicable Reliability Criteria for operating conditions that fall outside of the existing RMR designation criteria, primarily to provide additional local area support during Generating Unit and transmission outages.

Q. **WILL THE ISO PROVIDE ADDITIONAL INFORMATION ON MINIMUM LOAD COSTS FOR 2004?**

A. Yes. The ISO will update Exhibit Nos. ISO-5 and ISO-8 through 11 with data for September 2004 and October 2004 as the final settlements data become available. The ISO expects to provide this data by December 31, 2004.

CONCLUSION

Q. THANK YOU. I HAVE NO FURTHER QUESTIONS.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Folsom County of Sacramento	)

AFFIDAVIT OF WITNESS

I, Brian Theaker, being duly sworn, depose and say that the statements and exhibits contained in the Revised Direct Testimony on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 25th day of October, 2004.

Brian Theaker

Subscribed and sworn to before me this 25 day of October, 2004.

Notary Public
State of California

CAYDEN V. MOHR
Commission # 1293602
Notary Public - California
Sacramento County
My Comm. Expires Feb 9, 2005

EXHIBIT NO. ISO-2

EXHIBIT ISO-2
MONTHLY START-UP COSTS

Month	Start-Up Fuel Cost Collected	Paid Out	Refunded
June-01	45,433.66	-	(45,165.98)
July-01	138,160.90	31,045.37	(107,115.49)
August-01	142,575.90	14,099.67	(128,476.22)
September-01	128,801.39	24,543.72	(104,257.66)
October-01	125,356.00	2,109.89	(123,246.11)
November-01	117,569.12	28,251.57	(89,317.53)
December-01	123,197.29	29,711.55	(93,485.74)
January-02	124,814.19	36,808.67	(88,005.51)
February-02	110,528.81	4,599.02	(105,929.78)
March-02	121,510.61	23,662.11	(97,848.51)
April-02	118,263.72	34,992.44	(83,271.28)
May-02	126,239.33	42,380.10	(83,859.24)
June-02	132,513.45	84,602.37	(47,911.03)
July-02	146,957.44	63,590.35	
August-02	143,376.10	163,170.00	
September-02	136,177.35	340,065.69	
October-02	125,094.46	145,794.34	
November-02	120,088.08	117,334.68	
December-02	125,590.99	569,719.79	
January-03	121,176.01	176,205.46	
February-03	107,359.07	189,424.89	
March-03	122,807.91	278,371.87	
April-03	116,056.17	18,225.02	
May-03	125,002.98	128,129.53	
June-03	129,776.04	364,015.91	
July-03	152,916.42	320,453.31	
August-03	151,918.85	137,919.65	
September-03	140,756.62	48,615.87	
October-03	131,111.12	148,858.75	
November-03	118,796.43	47,017.18	
December-03	128,515.13	45,655.98	
January-04	385,445.31	130,697.42	
February-04	355,393.16	74,428.67	
March-04	382,165.66	140,546.58	
April-04	366,289.07	174,020.54	
May-04*	398,758.90	158,160.70	
Total	**5,786,493.64**	**4,337,228.64**	**$ 1,197,890.08**

* - Based on Preliminary Invoice

Start-Up Fuel Charge Rate	**June 2001 - December 2003**	**$0.00635/MWh**
	January 2004 - Current	**$0.0194/MWh**

EXHIBIT NO. ISO-3

EXHIBIT ISO-3
MONTHLY EMISSIONS COSTS

Month	Emissions Costs Collected	Emissions Costs Paid Out	Emissions Costs Refunded
June-01	244,554.76	-	(243,113.73)
July-01	743,675.61	-	(743,675.62)
August-01	767,440.03	-	(767,440.04)
September-01	693,296.50	-	(693,296.53)
October-01	674,751.04	-	(674,751.02)
November-01	632,836.55	-	(632,836.55)
December-01	663,131.38	-	(663,131.36)
January-02	671,834.47	-	(671,834.49)
February-02	594,940.87	-	(594,940.87)
March-02	654,052.19	-	(654,052.20)
April-02	636,575.41	-	(636,575.44)
May-02	679,505.64	-	(679,505.64)
June-02	713,277.29	(674,926.88)	(38,350.43)
Total *	**8,369,871.74**	**(674,926.88)**	**(7,693,503.92)**
July-02	791,024.40	(21,824.91)	
August-02	771,747.22	(11,876.53)	
September-02	732,998.61	(1,118,980.25)	
October-02	673,342.99	(27,981.26)	
November-02	646,395.27	(6,925.77)	
December-02	676,015.73	(146,543.39)	
January-03	652,251.34	(1,120.31)	
February-03	577,879.31	(2,435.96)	
March-03	661,035.35	(6,349.15)	
April-03	624,692.97		
May-03	672,850.87	(28,825.16)	
June-03	698,542.68		
July-03	823,099.73		
August-03	817,730.05		
September-03	757,647.54		
October-03	705,728.80		
November-03	639,442.74		
December-03	691,680.16		
January-04	0		
February-04	0		
March-04	0		
April-04	0		
May-04	0		
June-04			
July-04			
Total **	**20,983,977.50**	**(2,047,789.57)**	**(7,693,503.92)**

Emission Charge Rate June 01 - December 03 = $0.03418/MWh
January 2004 - Current = $0.0000MWh

EXHIBIT NO. ISO-4

Monthly Minimum Load Costs

Year	Month	MLCC	Annual Total
2001	May	$22,396	
	June	$1,195,220	
	July	$381,875	
	August	$481,262	
	September	$1,386,871	
	October	$280,542	
	November	$3,987,336	
	December	$3,156,082	$10,891,583
2002	January	$3,379,566	
	February	$988,012	
	March	$1,493,122	
	April	$3,139,467	
	May	$4,050,455	
	June	$7,332,578	
	July	$6,843,240	
	August	$6,590,805	
	September	$8,845,977	
	October	$4,761,231	
	November	$2,756,937	
	December	$10,608,584	$60,789,973
2003	January	$4,811,707	
	February	$4,286,405	
	March	$8,732,354	
	April	$5,364,107	
	May	$3,895,374	
	June	$9,594,072	
	July	$14,515,765	
	August	$20,588,662	
	September	$13,699,994	
	October	$15,227,582	
	November	$10,796,221	
	December	$13,656,350	$125,168,594
2004	January	$12,837,883	
	February	$13,044,691	
	March	$20,762,141	
	April	$18,465,699	
	May	$21,996,214	$87,106,628
	TOTAL	$283,956,779	

EXHIBIT NO. ISO-5

Monthly Minimum Load Costs

Month	Local	Zonal	System	Total
2004.06	$7,789,504	$16,957,242	$242,528	$24,989,273
2004.07	$3,798,315	$25,700,169	$3,646,427	$33,144,911
2004.08	$612,678	$28,549,534	$1,091,043	$30,253,255
Total	**$12,200,497**	**$71,206,945**	**$4,979,998**	**$88,387,439**

EXHIBIT NO. ISO-6

submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) Business Days following the last Trading Day in the month in which such costs were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.

5.11.6.1.4 Allocation of Minimum Load Costs

For each Settlement Interval, the ISO shall determine that the Minimum Load Costs for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Settlement Interval Minimum Load Costs and shall allocate those costs as follows:

1) if the Generating Unit was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Minimum Load costs shall be considered incremental locational costs.

Costs allocated under this part (1) shall be considered Reliability Services Costs.

2) if the Generating Unit was operating due to Inter-Zonal Congestion, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinator's monthly Demand in that Zone;

3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Minimum Load Costs in the following way:

   a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

   b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

5.11.6.1.5 Payment Of Available Capacity Under The Must-Offer Obligation

Available capacity that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as

EXHIBIT NO. ISO-7

5.11.6.1.4 Allocation of Minimum Load Costs

For each Settlement Interval, the ISO shall determine that the Minimum Load Costs for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. ~~Minimum Load Costs for the total number of~~

~~eligible hours for each unit shall be evenly divided over all such eligible hours.~~ For each such month ~~hour~~, the ISO shall sum the Settlement Interval ~~total~~ Minimum Load Costs and shall ~~be~~ allocate those costs~~d~~ as follows:

1) if the Generating Unit was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Minimum Load Costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.

2) if the Generating Unit was operating due to Inter-Zonal Congestion, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinators' monthly Demand in that Zone;

3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Minimum Load Costs in the following way:

   a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

EXHIBIT NO. ISO-8

MLCC Allocation for June - August 2004
Monthly Allocation - All Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
AEI1	$0	$0	$5,372	$0	$5,372
ANHM	$0	$2,790,082	$0	$0	$2,790,082
APS1	$0	$959,132	$0	$0	$959,132
APX1	$0	$74,674	$0	$0	$74,674
AZCO	$0	$25,895	$1,757	$0	$27,652
AZUA	$0	$141,110	$0	$0	$141,110
BAN1	$0	$93,084	$0	$0	$93,084
CAL1	$0	$0	$14,090	$0	$14,090
CALP	$0	$1,995	$108,073	$0	$110,068
CDWR	$0	$6,044,581	$43,898	$0	$6,088,479
CECO	$0	$401,439	$30,392	$0	$431,831
CLTN	$0	$196,004	$13,794	$0	$209,798
CMWD	$0	$0	$640	$0	$640
CNCO	$0	$0	$5,395	$0	$5,395
COTB	$0	$24,517	$2,259	$0	$26,776
CPA1	$0	$210,103	$58,465	$0	$268,567
CPSC	$0	$0	$972	$0	$972
CRLL	$0	$13,239	$15,093	$0	$28,332
CRLP	$0	$21,937	$1,011,520	$0	$1,033,457
CTID	$0	$3,516	$585	$0	$4,101
DEMA	$0	$0	$123	$0	$123
DETM	$0	$3	$349,099	$0	$349,102
ECH1	$0	$6,314	$0	$0	$6,314
EMMT	$0	$0	$3,276	$0	$3,276
FPPM	$0	$0	$50,941	$0	$50,941
GLEN	$0	$0	$6	$0	$6
HDPP	$0	$0	$217,176	$0	$217,176
IVLY	$0	$0	$423	$0	$423
KET3	$0	$0	$1,037	$0	$1,037
MID1	$0	$0	$1,920	$0	$1,920
MNEV	$0	$0	$15,158	$0	$15,158
MSCG	$0	$0	$22,941	$0	$22,941
MWSC	$0	$0	$10,664	$0	$10,664
NCPA	$0	$18,981	$0	$0	$18,981
NEI1	$0	$1,532,002	$148,961	$0	$1,680,964
NES1	$0	$4,365	$0	$0	$4,365
OPSI	$0	$0	$84,837	$0	$84,837
PAC1	$0	$0	$1,004	$0	$1,004
PASA	$0	$634,772	$0	$0	$634,772
PCG2	$0	$493,634	$247,559	$0	$741,192
PCPM	$0	$0	$37,264	$0	$37,264
PGAB	$219,818	$14,069	$190	$0	$234,076
PIPO	$0	$427,591	$106,778	$0	$534,369

MLCC Allocation for June - August 2004
Monthly Allocation - All Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
PWRX	$0	$0	$11,831	$0	$11,831
RVSD	$0	$2,293,966	$0	$0	$2,293,966
SCE1	$11,980,679	$41,611,959	$646,814	$0	$54,239,452
SCE2	$0	$0	$69,510	$0	$69,510
SCE5	$0	$0	$10,740	$0	$10,740
SDG3	$0	$8,213,253	$44,362	$0	$8,257,615
SDGE	$0	$0	$50,855	$0	$50,855
SEES	$0	$1,637,319	$877,383	$0	$2,514,703
SEL1	$0	$2,653,804	$71,206	$0	$2,725,010
SETC	$0	$696	$508,400	$0	$509,095
SNCL	$0	$0	$1,816	$0	$1,816
SRP1	$0	$0	$4,460	$0	$4,460
TEMU	$0	$0	$48,019	$0	$48,019
VERN	$0	$597,957	$3,052	$0	$601,009
VSYN	$0	$16,606	$0	$0	$16,606
WAES	$0	$0	$2	$0	$2
WAMP	$0	$0	$8,354	$0	$8,354
WCSL	$0	$676	$0	$0	$676
WDOE	$0	$5,311	$7,799	$0	$13,110
WEPA	$0	$40,345	$0	$0	$40,345
WESC	$0	$988	$0	$0	$988
WLMD	$0	$845	$3,689	$0	$4,534
WRDG	$0	$182	$42	$0	$224
Total	**$12,200,497**	**$71,206,945**	**$4,979,997**	**$0**	**$88,387,439**

Zonal Reason	MLCC
NP15 CAP	$168,636
PATH15	$472,656
S-LUGO	$25,285,929
SCIT	$29,314,315
SYLMAR	$15,965,409
Total	**$71,206,945**

EXHIBIT NO. ISO-9

MLCC Allocation for June - August 2004
Daily Allocation - All Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
AEI1	$0	$0	$6,037	$0	$6,037
ANHM	$0	$2,783,228	$0	$0	$2,783,228
APS1	$0	$952,806	$6,665	$0	$959,471
APX1	$0	$74,160	$500	$0	$74,661
APX3	$0	$0	$1,816	$0	$1,816
AZCO	$0	$26,029	$1,526	$0	$27,554
AZUA	$0	$141,510	$1,421	$0	$142,931
BAN1	$0	$94,318	$2,357	$0	$96,675
BPEC	$0	$0	$1,879	$0	$1,879
CAL1	$0	$0	$10,890	$0	$10,890
CALP	$0	$1,625	$97,720	$0	$99,344
CDWR	$0	$5,989,832	$64,933	$0	$6,054,766
CECO	$0	$401,444	$34,759	$0	$436,203
CLTN	$0	$195,555	$16,363	$0	$211,918
CMWD	$0	$0	$1,184	$0	$1,184
CNCO	$0	$0	$9,204	$0	$9,204
COTB	$0	$23,370	$6,161	$0	$29,531
CPA1	$0	$201,500	$55,127	$0	$256,627
CPSC	$0	$0	$764	$0	$764
CRLL	$0	$13,279	$13,081	$0	$26,360
CRLP	$0	$21,986	$949,651	$0	$971,637
CTID	$0	$3,647	$5,270	$0	$8,917
DETM	$0	$4	$307,593	$0	$307,596
ECH1	$0	$6,072	$0	$0	$6,072
EMMT	$0	$0	$4,430	$0	$4,430
EPME	$0	$0	$632	$0	$632
FPPM	$0	$0	$34,259	$0	$34,259
GLEN	$0	$0	$5	$0	$5
HDPP	$0	$0	$183,398	$0	$183,398
IVLY	$0	$0	$332	$0	$332
KET3	$0	$0	$1,046	$0	$1,046
MID1	$0	$0	$7,864	$0	$7,864
MNEV	$0	$0	$10,485	$0	$10,485
MRNT	$0	$0	$10,367	$0	$10,367
MSCG	$0	$0	$17,460	$0	$17,460
MWSC	$0	$0	$9,965	$0	$9,965
NCPA	$0	$18,215	$12,480	$0	$30,695
NEI1	$0	$1,526,055	$135,508	$0	$1,661,563
NES1	$0	$4,382	$479	$0	$4,861
OPSI	$0	$0	$70,481	$0	$70,481
PAC1	$0	$0	$753	$0	$753
PASA	$0	$637,821	$17,084	$0	$654,904
PCG2	$0	$493,200	$399,735	$0	$892,934

MLCC Allocation for June - August 2004
Daily Allocation - All Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
PCPM	$0	$0	$36,299	$0	$36,299
PGAB	$219,818	$15,372	$8,401	$0	$243,591
PIPO	$0	$422,568	$74,932	$0	$497,500
PWRX	$0	$0	$20,421	$0	$20,421
RVSD	$0	$2,315,342	$874	$0	$2,316,216
SCE1	$11,980,679	$41,708,533	$702,322	$0	$54,391,535
SCE2	$0	$0	$57,590	$0	$57,590
SCE5	$0	$0	$6,070	$0	$6,070
SDG3	$0	$8,207,740	$35,083	$0	$8,242,822
SDGE	$0	$0	$43,746	$0	$43,746
SEES	$0	$1,629,205	$773,878	$0	$2,403,083
SEL1	$0	$2,641,894	$57,220	$0	$2,699,113
SETC	$0	$824	$444,582	$0	$445,406
SNCL	$0	$0	$3,843	$0	$3,843
SRP1	$0	$0	$5,431	$0	$5,431
TEMU	$0	$0	$54,205	$0	$54,205
VERN	$0	$590,680	$5,060	$0	$595,740
VSYN	$0	$16,485	$1,897	$0	$18,381
WAES	$0	$0	$118,646	$0	$118,646
WAMP	$0	$0	$5,752	$0	$5,752
WCSL	$0	$690	$0	$0	$690
WDOE	$0	$5,506	$8,447	$0	$13,953
WEPA	$0	$39,885	$23	$0	$39,908
WESC	$0	$1,002	$0	$0	$1,002
WLMD	$0	$868	$3,522	$0	$4,390
WRDG	$0	$314	$93	$0	$407
Total	**$12,200,497**	**$71,206,945**	**$4,979,997**	**$0**	**$88,387,439**

EXHIBIT NO. ISO-10

MLCC Allocation for June - August 2004
Monthly Allocation – On-Peak Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
AEI1	$0	$0	$6,214	$0	$6,214
ANHM	$0	$2,841,134	$0	$0	$2,841,134
APS1	$0	$926,157	$0	$0	$926,157
APX1	$0	$73,211	$0	$0	$73,211
AZCO	$0	$26,525	$1,668	$0	$28,193
AZUA	$0	$144,486	$0	$0	$144,486
BAN1	$0	$96,784	$0	$0	$96,784
CAL1	$0	$0	$7,145	$0	$7,145
CALP	$0	$1,822	$135,957	$0	$137,779
CDWR	$0	$4,887,344	$72,536	$0	$4,959,880
CECO	$0	$423,045	$39,376	$0	$462,421
CLTN	$0	$196,588	$9,707	$0	$206,295
CMWD	$0	$0	$423	$0	$423
CNCO	$0	$0	$5,365	$0	$5,365
COTB	$0	$24,622	$2,490	$0	$27,112
CPA1	$0	$202,586	$58,675	$0	$261,260
CPSC	$0	$0	$831	$0	$831
CRLL	$0	$12,677	$13,671	$0	$26,347
CRLP	$0	$20,267	$1,023,222	$0	$1,043,489
CTID	$0	$3,615	$200	$0	$3,815
DETM	$0	$3	$488,500	$0	$488,503
ECH1	$0	$5,742	$0	$0	$5,742
EMMT	$0	$0	$8,965	$0	$8,965
FPPM	$0	$0	$57,813	$0	$57,813
GLEN	$0	$0	$3	$0	$3
HDPP	$0	$0	$206,955	$0	$206,955
IVLY	$0	$0	$348	$0	$348
KET3	$0	$0	$389	$0	$389
MID1	$0	$0	$2,311	$0	$2,311
MNEV	$0	$0	$6,766	$0	$6,766
MSCG	$0	$0	$11,407	$0	$11,407
MWSC	$0	$0	$13,453	$0	$13,453
NCPA	$0	$20,164	$0	$0	$20,164
NEI1	$0	$1,494,739	$146,333	$0	$1,641,073
NES1	$0	$2,379	$0	$0	$2,379
OPSI	$0	$0	$80,046	$0	$80,046
PAC1	$0	$0	$833	$0	$833
PASA	$0	$663,409	$0	$0	$663,409
PCG2	$0	$496,909	$181,928	$0	$678,837
PCPM	$0	$0	$79,162	$0	$79,162
PGAB	$219,818	$14,604	$1,816	$0	$236,237
PIPO	$0	$398,809	$78,366	$0	$477,175
PWRX	$0	$0	$8,657	$0	$8,657

MLCC Allocation for June - August 2004
Monthly Allocation – On-Peak Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
RVSD	$0	$2,360,449	$0	$0	$2,360,449
SCE1	$11,980,679	$42,624,120	$638,667	$0	$55,243,466
SCE2	$0	$0	$63,393	$0	$63,393
SCE5	$0	$0	$8,717	$0	$8,717
SDG3	$0	$8,325,856	$26,657	$0	$8,352,513
SDGE	$0	$0	$43,033	$0	$43,033
SEES	$0	$1,554,592	$770,676	$0	$2,325,269
SEL1	$0	$2,722,170	$85,273	$0	$2,807,443
SETC	$0	$478	$506,210	$0	$506,688
SNCL	$0	$0	$1,687	$0	$1,687
SRP1	$0	$0	$4,283	$0	$4,283
TEMU	$0	$0	$49,819	$0	$49,819
VERN	$0	$580,188	$1,009	$0	$581,197
VSYN	$0	$16,559	$0	$0	$16,559
WAES	$0	$0	$6,769	$0	$6,769
WAMP	$0	$0	$8,513	$0	$8,513
WCSL	$0	$603	$0	$0	$603
WDOE	$0	$5,016	$10,155	$0	$15,171
WEPA	$0	$37,492	$0	$0	$37,492
WESC	$0	$694	$0	$0	$694
WLMD	$0	$867	$3,587	$0	$4,455
WRDG	$0	$241	$21	$0	$262
Total	**$12,200,497**	**$71,206,945**	**$4,979,997**	**$0**	**$88,387,439**

EXHIBIT NO. ISO-11

MLCC Allocation for June - August 2004
Daily Allocation – On-Peak Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
AEI1	$0	$0	$7,008	$0	$7,008
ANHM	$0	$2,829,750	$0	$0	$2,829,750
APS1	$0	$918,538	$7,391	$0	$925,929
APX1	$0	$72,697	$1,214	$0	$73,912
APX3	$0	$0	$3,789	$0	$3,789
AZCO	$0	$26,698	$1,438	$0	$28,136
AZUA	$0	$144,703	$1,156	$0	$145,859
BAN1	$0	$98,125	$2,505	$0	$100,631
BPEC	$0	$0	$3,824	$0	$3,824
CAL1	$0	$0	$3,533	$0	$3,533
CALP	$0	$1,370	$108,626	$0	$109,997
CDWR	$0	$4,866,848	$88,968	$0	$4,955,816
CECO	$0	$423,037	$41,834	$0	$464,871
CLTN	$0	$195,949	$12,389	$0	$208,337
CMWD	$0	$0	$1,008	$0	$1,008
CNCO	$0	$0	$9,099	$0	$9,099
COTB	$0	$23,510	$7,294	$0	$30,804
CPA1	$0	$194,340	$55,467	$0	$249,808
CPSC	$0	$0	$743	$0	$743
CRLL	$0	$12,735	$11,735	$0	$24,470
CRLP	$0	$20,145	$957,676	$0	$977,821
CTID	$0	$3,726	$2,318	$0	$6,043
DETM	$0	$3	$427,899	$0	$427,902
ECH1	$0	$5,467	$109	$0	$5,576
EMMT	$0	$0	$9,761	$0	$9,761
EPME	$0	$0	$863	$0	$863
FPPM	$0	$0	$39,201	$0	$39,201
GLEN	$0	$0	$3	$0	$3
HDPP	$0	$0	$159,753	$0	$159,753
IVLY	$0	$0	$338	$0	$338
KET3	$0	$0	$168	$0	$168
MID1	$0	$0	$10,289	$0	$10,289
MNEV	$0	$0	$4,024	$0	$4,024
MRNT	$0	$0	$21,194	$0	$21,194
MSCG	$0	$0	$9,280	$0	$9,280
MWSC	$0	$0	$12,412	$0	$12,412
NCPA	$0	$19,380	$42,829	$0	$62,210
NEI1	$0	$1,486,945	$136,478	$0	$1,623,423
NES1	$0	$2,295	$1,707	$0	$4,002
OPSI	$0	$0	$58,081	$0	$58,081
PAC1	$0	$0	$752	$0	$752
PASA	$0	$665,830	$28,357	$0	$694,187
PCG2	$0	$496,764	$410,587	$0	$907,351

MLCC Allocation for June - August 2004
Daily Allocation – On-Peak Hours

SC	Local	Zonal	System (Tier I)	System (Tier II)	Total
PCPM	$0	$0	$52,285	$0	$52,285
PGAB	$219,818	$15,882	$13,835	$0	$249,535
PIPO	$0	$393,034	$58,182	$0	$451,216
PWRX	$0	$0	$22,608	$0	$22,608
RVSD	$0	$2,382,188	$1,118	$0	$2,383,307
SCE1	$11,980,679	$42,706,363	$629,381	$0	$55,316,423
SCE2	$0	$0	$53,248	$0	$53,248
SCE5	$0	$0	$4,543	$0	$4,543
SDG3	$0	$8,316,692	$14,075	$0	$8,330,766
SDGE	$0	$0	$37,321	$0	$37,321
SEES	$0	$1,544,448	$665,303	$0	$2,209,751
SEL1	$0	$2,706,349	$67,064	$0	$2,773,413
SETC	$0	$558	$433,180	$0	$433,738
SNCL	$0	$0	$4,006	$0	$4,006
SRP1	$0	$0	$5,352	$0	$5,352
TEMU	$0	$0	$60,462	$0	$60,462
VERN	$0	$571,259	$3,103	$0	$574,362
VSYN	$0	$16,416	$2,761	$0	$19,177
WAES	$0	$0	$129,861	$0	$129,861
WAMP	$0	$0	$5,482	$0	$5,482
WCSL	$0	$606	$0	$0	$606
WDOE	$0	$5,292	$10,086	$0	$15,379
WEPA	$0	$36,999	$3	$0	$37,003
WESC	$0	$697	$0	$0	$697
WLMD	$0	$890	$3,540	$0	$4,430
WRDG	$0	$416	$95	$0	$511
Total	**$12,200,497**	**$71,206,945**	**$4,979,997**	**$0**	**$88,387,439**

CERTIFICATE OF SERVICE

I hereby certify I have this day served the foregoing document on each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Folsom, CA, on this 26th day of October, 2004.

Geeta O. Tholan /

Geeta O. Tholan