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August 16, 2004

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 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. EL04-103-000 (Consolidated)

Dear Secretary Salas:

Enclosed are an original and seven copies of the Direct Testimony of Brian D. Theaker on Behalf of the California Independent System Operator Corporation, and supporting exhibits, submitted in the above-captioned proceeding.

Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by the messenger. Two courtesy copies of this filing are being provided to Presiding Administrative Law Judge H. Peter Young. Please contact the undersigned if you have any questions regarding this filing. Thank you for your assistance.

Sincerely,

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Counsel for the California
Independent System Operator
Corporation

Enclosures

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
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 four 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; and when the ISO proposes to make the revised cost allocation effective.

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.

In deciding to modify aspects of the must-offer process, including the allocation of must-offer costs, the ISO solicited comments and questions from Market Participants concerning the must-offer process, and undertook a stakeholder process. The ISO addressed the views of stakeholders on the issue of cost allocation.

The ISO's proposal for allocating must-offer costs was contained in Amendment No. 60 to its Tariff. The ISO did not propose to change how Start-Up Costs and Emissions Costs are allocated. However, the ISO did propose 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 that is based on cost-causation principles. The ISO proposed to allocate the three categories of Minimum Load Costs as follows: Minimum Load Costs for local reliability reasons would be allocated to the Participating TO in whose service territory the Generating Unit is located on a monthly basis; Minimum Load Costs for Zonal requirements would be allocated to total monthly Demand within the affected Zone; and Minimum Load Costs for system (*i.e.*, Control Area-wide) requirements would be allocated first to monthly Net Negative Uninstructed Deviations up to a capped dollar per megawatt-hour rate, with any costs in excess of the capped rate being allocated to monthly Control Area Demand and monthly in-state imports.

Mr. Theaker explains that local reliability costs should be allocated to the Participating Transmission Owner because they are 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. 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. 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.

The ISO also commits and operates Generating Units under the must-offer obligation for system requirements when the ISO expects Demand in the Control Area will exceed the Supply 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, 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 the right quantity on which to allocate the costs of the ISO procuring the additional Supply needed to keep the ISO Control Area in balance. The ISO has proposed a "cap" on these charges to ensure that a small amount of Net Negative Uninstructed Deviations could not incur a disproportionate and unreasonable amount of Minimum Load Costs.

Mr. Theaker explains that wheel-through schedules contribute to power flows on inter-regional paths in the same way that Energy produced outside the ISO Control Area and destined for delivery within the ISO Control Area does, and therefore it is reasonable to charge a portion of the Minimum Load Costs from Generating Units that are committed and operating to manage flows or maintain voltages on those inter-regional transmission paths to wheel-through transactions. The testimony also explains that while there is a time-related factor in Minimum Load Costs, cost responsibility for Minimum Load Costs cannot be sufficiently be assigned to off-peak and on-peak categories to justify such an allocation.

In Amendment No. 60, the ISO proposed to make the revised cost allocation effective October 1, 2004. In Mr. Theaker's testimony, the ISO requests that the presiding Administrative Law Judge accept Pacific Gas and Electric Company'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.

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. EL04-103-000
v.	)	
California Independent System Operator Corporation	)	(Consolidated)

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.

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.

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 at night and 6 AM in the morning, when demand for electricity it 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.

In Amendment No. 62, tendered for filing on August 3, 2004, the ISO proposed to modify the definition of Start-Up Costs contained in the ISO Tariff so that the ISO would pay these Start-Up Costs from the time of first fire until the earlier of (a) the time the Generating Unit reached its minimum operating level or (b) the time the Generating Unit was synchronized to the grid plus the Generating Unit's maximum start-up time as recorded in the ISO Master File.

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 2003 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 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 & 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 are scheduled for implementation on October 1, 2004. 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 ("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. HOW DOES THE ISO DISTINGUISH BETWEEN LOCAL RELIABILITY COSTS AND ZONAL COSTS?

A. In Amendment No. 60, the ISO proposed that the costs of Generating Units committed and operated under the must-offer obligation be allocated to the Participating TO if the Generating Unit was managing flows on a transmission line not considered to be an Inter-Zonal interface. Inter-Zonal interfaces are the paths between the three existing ISO Congestion Zones – NP15, ZP26, and SP15. 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.

There currently are three constraints that the ISO operates Generating Units for under the must-offer obligation that should be classified as Zonal constraints and for which the Minimum Load Costs for which should be allocated Zonally: (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.

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 proposed to allocate these costs Zonally in Amendment No. 60 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. 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. 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, 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 the right 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 Deviations 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 their 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 they are 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). The places where new Generating Units locate on the grid are 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 are reasonable places 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. Wheel-through schedules – schedules for power not produced in nor to be delivered within the ISO Control Area, but merely flowing through the ISO Control Area - contribute to power flows on these inter-regional paths in the same way that Energy produced outside the ISO Control Area and destined for delivery within the ISO Control Area does. It is therefore reasonable to charge a portion of the Minimum Load Costs from Generating Units that are committed and operating to manage flows or maintain voltages on those inter-regional transmission paths. SMUD noted in its protest to Amendment No. 60 that under the current method for allocating must-offer costs (to Demand within the Control Area and exports to other Control Areas within California), a wheel–through transaction from the Bonneville Power Administration to SMUD would be allocated a portion of the must-offer costs (because the Energy is exported from the ISO Control Area to another Control Area within California), while a wheel-through transaction in the opposite direction, from SMUD to BPA, would not (because the Energy is exported to a Control Area not within California). While SMUD is trying to show the folly in this disparity, in reality, this outcome makes sense. In instances in which SMUD's imports from BPA are contributing to inter-regional flows into California that must be managed by committing and dispatching Generating Units in California, SMUD rightly should be allocated a share of the cost of doing so. If SMUD is exporting power to BPA in the direction opposite to the direction of Congestion into California from the north, it is not contributing to that Congestion and should not bear any congestion-related costs. If congestion was in the opposite direction – from California to the Pacific Northwest – the ISO would not be committing and dispatching California generation to mitigate that overload and no related charges would accrue to any ISO Market Participant, including SMUD. The direction of the power transaction, and whether that transaction contributes to the need to manage flows either by the ISO or by BPA does make a difference on what costs it should be charged.

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. DOES THE ISO AGREE?

A. No. Although there is a time related factor in Minimum Load Costs (e.g., two of the chronic reliability issues the ISO faces in Southern California that require use of Generating Units under the must-offer obligation – managing the SCIT nomogram and the South-Of-Lugo path – typically occur only during on-peak periods), cost responsibility for Minimum Load Costs cannot sufficiently be assigned to off-peak and on-peak categories to justify such an allocation. For example, as shown in Exhibit ISO-8, Overloads on the 230/220-kV transformer banks at Sylmar, the southern terminus of the +/- 500-kV Pacific DC Intertie, often require Energy from specific Southern California Generating Units in all hours of the day, not just during peak hours. These costs are allocated to the Participating TO, which reflects cost causation far more directly than a time-of-use rate. Similarly, when the ISO commits and operates Generating Units to meet Control Area requirements, the Minimum Load Costs are first allocated to monthly Net Negative Uninstructed Deviations, up to a capped rate, which again directs cost-causation more directly than a time-of-use rate. Although remaining

Minimum Load Costs above the capped rate are allocated to all Demand within the ISO Control Area and to in-state exports, these are not expected to be significant, and the administrative costs of administering a time-of-use rate outweigh any benefits.

Q. AMENDMENT NO. 60 ALLOCATES MINIMUM LOAD COSTS ON A MONTHLY BASIS. HAS THE ISO ACKNOLWEDGED 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.

Q. IN AMENDMENT NO. 60, THE ISO ACKNOWLEDGED THAT IT COMMITS AN ADDITIONAL "MARGIN" OF GENERATING CAPACITY TO ACCOUNT FOR EXPECTED LOAD FORECAST ERROR. TO WHOM SHOULD THOSE COSTS BE ALLOCATED?

A. This margin provides additional capacity that would be used to meet Control Area demand requirements should the load forecast be in error, typically due to an error in the weather forecast. This capacity benefits the entire Control Area and its costs should be allocated as the ISO proposed – first to Net Negative Uninstructed Deviation up to the capped rate, with any remaining costs allocated to Control Area Demand and in-state exports.

Q. IF THE ISO ALLOCATED 2003 MINIMUM LOAD COSTS BASED ON ITS PROPOSAL, HOW WOULD THE COSTS BE ALLOCATED?

A. This data is presented as Exhibit No. ISO-9. 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 Path 15, Path 26 and the California-Oregon Intertie (COI), or (2) the Generating Unit was committed and operated under the must-offer obligation to maintain operations within the SCIT nomogram.

Q. HAS THE ISO CALCULATED ALLOCATING 2003 MINIMUM LOAD COSTS OTHER WAYS?

A. Yes. The ISO has also calculated other allocations of Minimum Load Costs. Exhibits ISO-10 through ISO-12 show how Minimum Load Costs would be allocated (1) if certain transmission constraints are classified as Zonal rather than as local, and (2) if the allocation is performed on a daily basis rather than on a monthly basis.

Q. HAS THE ISO ESTIMATED HOW 2004 MINIMUM LOAD COSTS WOULD BE CLASSIFIED?

A. Yes. Exhibit 13 shows how Minimum Load Costs for January 1, 2004 through May 31, 2004 would be classified as for local, Zonal or system reliability depending on whether the South of Lugo constraint and the Miguel constraint are classified as local or Zonal.

Q. HAS THE ISO INCLUDED ITS PROPOSAL TO CHARGE ONLY THE "NET

INCREMENTAL COST" TO THE PARTICIPATING TO IN ITS COST ALLOCATION CALCULATIONS?

A. No. The SCUC application approved by the Commission in its July 8, 2004 order on Amendment No. 60 must be in service before the ISO can calculate the net incremental cost of starting up and operating a particular Generating Unit needed for local reliability rather than starting up and operating a less expensive Generating Unit that would also have met system needs but was not started-up because the system needs were also met by the Generating Unit started up and operated for local reliability needs.

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 and would not 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.

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 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 13 day of August, 2004.

Brian Theaker

Subscribed and sworn to before
me this 13 day of August, 2004.

Cayden V. Mohr
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	Paid Out	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
Categorized by reason
January 2003 – May 2004

Month	Local	Zonal	System	Total
2003.01	$0	$0	$4,811,707	$4,811,707
2003.02	$114,105	$0	$4,172,300	$4,286,405
2003.03	$6,044,825	$134,547	$2,552,982	$8,732,354
2003.04	$2,544,815	$1,447,254	$1,372,037	$5,364,107
2003.05	$419,727	$2,879,547	$511,527	$3,810,800
2003.06	$1,225,055	$3,319,379	$5,049,638	$9,594,072
2003.07	$1,729,473	$3,885,519	$8,827,589	$14,442,581
2003.08	$6,003,069	$9,303,024	$5,282,568	$20,588,662
2003.09	$7,139,902	$4,087,639	$2,471,066	$13,698,606
2003.10	$7,379,928	$6,144,374	$1,703,281	$15,227,582
2003.11	$7,781,944	$1,259,235	$1,755,041	$10,796,221
2003.12	$13,145,764	$405,341	$105,245	$13,656,350
2003 Total	**$53,528,608**	**$32,865,859**	**$38,614,982**	**$125,009,449**
2004.01	$3,951,476	$8,789,571	$96,836	$12,837,883
2004.02	$7,729,095	$4,858,271	$457,325	$13,044,691
2004.03	$16,983,709	$3,356,906	$421,527	$20,762,141
2004.04	$13,184,776	$5,066,638	$214,286	$18,465,699
2004.05	$17,996,925	$4,269,415	$324,718	$22,591,059
2004 Total	**$59,845,980**	**$26,340,802**	**$1,514,692**	**$87,701,473**

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

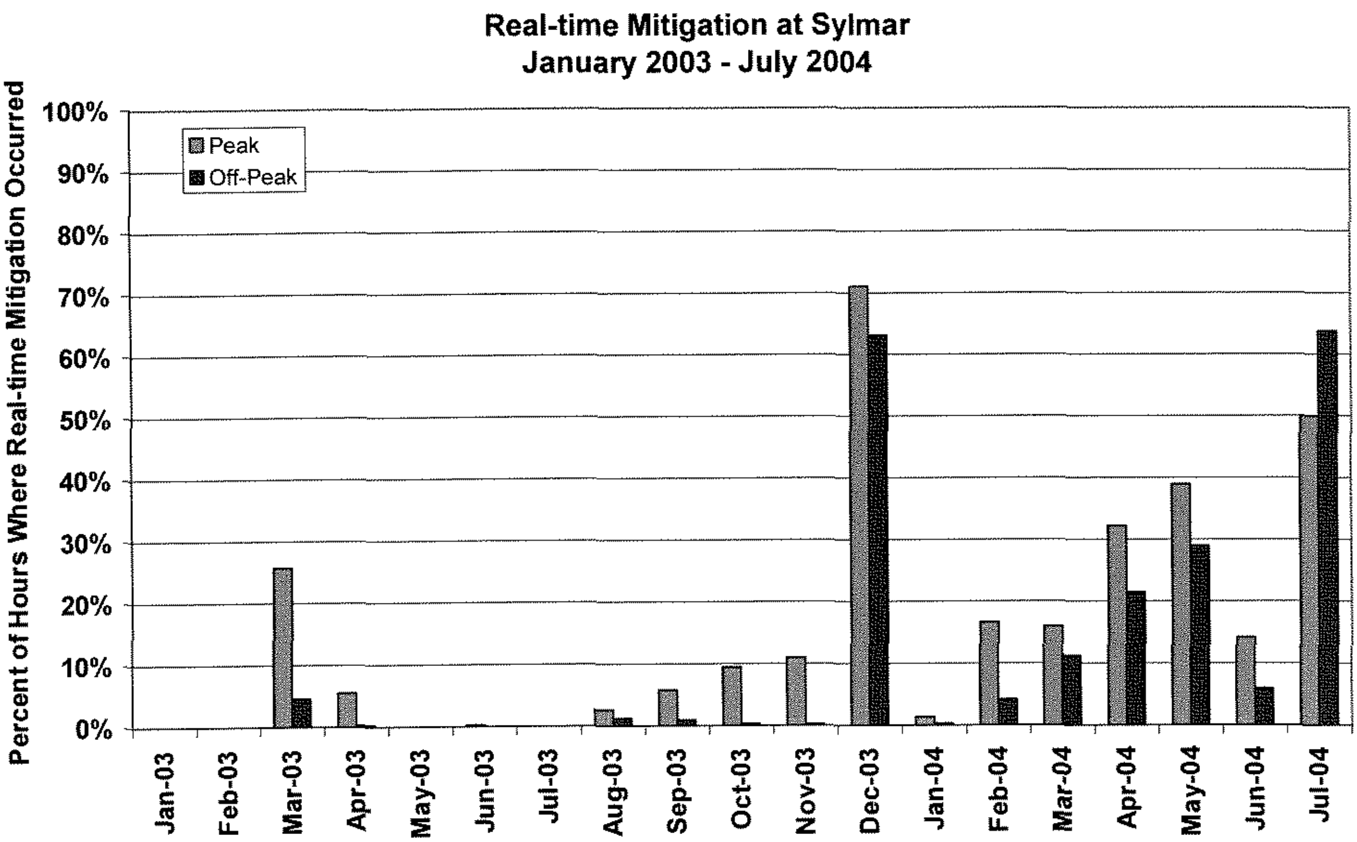
Real-time Mitigation at Sylmar
January 2003 - July 2004
Percent of Hours Where Real-time Mitigation Occurred
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Peak
Off-Peak
Jan-03
Feb-03
Mar-03
Apr-03
May-03
Jun-03
Jul-03
Aug-03
Sep-03
Oct-03
Nov-03
Dec-03
Jan-04
Feb-04
Mar-04
Apr-04
May-04
Jun-04
Jul-04

EXHIBIT NO. ISO-9

MLCC Allocation for Operating Year 2003
Monthly Allocation (South-of-Lugo and Miguel Local)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
AEI1	$0	$0	$231	$0	$231
AEPS	$0	$0	$35	$0	$35
ANHM	$0	$8,745	$2,442	$0	$11,186
APS1	$0	$634,660	$357,624	$0	$992,285
APX1	$0	$130,064	$1,195,268	$0	$1,325,332
APX3	$0	$0	$1,464	$0	$1,464
APX4	$0	$0	$1	$0	$1
APX5	$0	$0	$0	$0	$0
AZUA	$0	$33,270	$12,837	$0	$46,107
BAN1	$0	$15,058	$7,709	$0	$22,767
CAL1	$0	$0	$2,584	$0	$2,584
CALP	$0	$434	$936,607	$0	$937,041
CDWR	$0	$493,836	$329,136	$0	$822,972
CECO	$0	$166,681	$264,666	$0	$431,347
CLTN	$0	$45,085	$144,267	$0	$189,352
CMWD	$0	$0	$8,178	$0	$8,178
CNCO	$0	$0	$12,074	$0	$12,074
COTB	$0	$1,972	$414,867	$0	$416,839
CPSC	$0	$0	$55	$0	$55
CRLP	$0	$51,816	$1,645,832	$0	$1,697,649
CTID	$0	$0	$14,309	$0	$14,309
DETM	$0	$0	$1,428,380	$0	$1,428,380
ECH1	$0	$0	$427,651	$0	$427,651
EMMT	$0	$0	$123,915	$0	$123,915
EPME	$0	$0	$8,321	$0	$8,321
FPPM	$0	$0	$0	$0	$0
GLEN	$0	$0	$5	$0	$5
HDPP	$0	$0	$546,916	$0	$546,916
IDAC	$0	$5,118	$6,845	$0	$11,964
MAEM	$0	$0	$89,311	$0	$89,311
MIRA	$0	$0	$5	$0	$5
MNEV	$0	$0	$606	$0	$606
MRNT	$0	$0	$163,077	$0	$163,077
MSCG	$0	$0	$272	$0	$272
MWSC	$0	$0	$37,885	$0	$37,885
NCPA	$0	$729	$90,594	$0	$91,322
NEI1	$0	$1,420,717	$1,714,212	$0	$3,134,929
NES1	$0	$0	$385,361	$0	$385,361
OPSI	$0	$0	$274,552	$0	$274,552
PAC1	$0	$0	$1,306	$0	$1,306
PASA	$0	$228,202	$78,681	$0	$306,883
PCG2	$0	$167,873	$12,269,911	$0	$12,437,785
PCGB	$0	$0	$1,874,654	$0	$1,874,654
PCPM	$0	$0	$237,066	$0	$237,066

MLCC Allocation for Operating Year 2003
Monthly Allocation (South-of-Lugo and Miguel Local)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
PETP	$0	$88	$89,908	$0	$89,996
PGAB	$0	$2,866	$283,352	$0	$286,218
PGET	$0	$0	$1,722,416	$0	$1,722,416
PWRX	$0	$0	$2,671	$0	$2,671
RVSD	$0	$10,852	$9,174	$0	$20,025
RWET	$0	$0	$4	$0	$4
SCE1	$59,987,789	$13,979,725	$2,834,050	$0	$76,801,564
SCE2	$0	$0	$127,511	$0	$127,511
SCE5	$0	$0	$31,292	$0	$31,292
SDG3	$882,154	$4,313,067	$1,620,706	$0	$6,815,926
SDGE	$0	$0	$0	$0	$0
SEES	$0	$1,661,937	$2,552,984	$0	$4,214,922
SEL1	$0	$1,579,975	$1,876,219	$0	$3,456,194
SETC	$0	$2,566	$1,114,067	$0	$1,116,633
SNCL	$0	$0	$4	$0	$4
SPPC	$0	$0	$4,110	$0	$4,110
SRP1	$0	$0	$322	$0	$322
TBEL	$0	$0	$322	$0	$322
TEMU	$0	$0	$1,158	$0	$1,158
VERN	$0	$282,998	$60,956	$0	$343,954
VSYN	$0	$284,426	$632,062	$0	$916,488
WAMP	$0	$273	$59,184	$0	$59,457
WDOE	$0	$167	$3,805	$0	$3,972
WEMT	$0	$0	$49,133	$0	$49,133
WEPA	$0	$1,137	$476	$0	$1,614
WESC	$0	$187	$407,258	$0	$407,445
WLMD	$0	$0	$14,873	$0	$14,873
WRDG	$0	$0	$7,247	$0	$7,247
Total	**$60,869,942**	**$25,524,525**	**$38,614,982**	**$0**	**$125,009,449**

EXHIBIT NO. ISO-10

MLCC Allocation for Operating Year 2003
Monthly Allocation (South of Lugo and Miguel Zonal)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
AEI1	$0	$0	$231	$0	$231
AEPS	$0	$0	$35	$0	$35
ANHM	$0	$11,292	$2,442	$0	$13,734
APS1	$0	$841,336	$357,624	$0	$1,198,961
APX1	$0	$163,022	$1,195,268	$0	$1,358,290
APX3	$0	$0	$1,464	$0	$1,464
APX4	$0	$0	$1	$0	$1
APX5	$0	$0	$0	$0	$0
AZUA	$0	$44,782	$12,837	$0	$57,619
BAN1	$0	$20,231	$7,709	$0	$27,940
CAL1	$0	$0	$2,584	$0	$2,584
CALP	$0	$434	$936,607	$0	$937,041
CDWR	$0	$602,834	$329,136	$0	$931,970
CECO	$0	$229,146	$264,666	$0	$493,812
CLTN	$0	$61,511	$144,267	$0	$205,778
CMWD	$0	$0	$8,178	$0	$8,178
CNCO	$0	$0	$12,074	$0	$12,074
COTB	$0	$1,972	$414,867	$0	$416,839
CPSC	$0	$0	$55	$0	$55
CRLP	$0	$62,940	$1,645,832	$0	$1,708,772
CTID	$0	$0	$14,309	$0	$14,309
DETM	$0	$0	$1,428,380	$0	$1,428,380
ECH1	$0	$0	$427,651	$0	$427,651
EMMT	$0	$0	$123,915	$0	$123,915
EPME	$0	$0	$8,321	$0	$8,321
FPPM	$0	$0	$0	$0	$0
GLEN	$0	$0	$5	$0	$5
HDPP	$0	$0	$546,916	$0	$546,916
IDAC	$0	$6,454	$6,845	$0	$13,300
MAEM	$0	$0	$89,311	$0	$89,311
MIRA	$0	$0	$5	$0	$5
MNEV	$0	$0	$606	$0	$606
MRNT	$0	$0	$163,077	$0	$163,077
MSCG	$0	$0	$272	$0	$272
MWSC	$0	$0	$37,885	$0	$37,885
NCPA	$0	$729	$90,594	$0	$91,322
NEI1	$0	$1,823,462	$1,714,212	$0	$3,537,674
NES1	$0	$0	$385,361	$0	$385,361
OPSI	$0	$0	$274,552	$0	$274,552
PAC1	$0	$0	$1,306	$0	$1,306
PASA	$0	$289,188	$78,681	$0	$367,869
PCG2	$0	$168,044	$12,269,911	$0	$12,437,955
PCGB	$0	$0	$1,874,654	$0	$1,874,654
PCPM	$0	$0	$237,066	$0	$237,066

MLCC Allocation for Operating Year 2003
Monthly Allocation (South of Lugo and Miguel Zonal)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
PETP	$0	$88	$89,908	$0	$89,996
PGAB	$0	$2,866	$283,352	$0	$286,218
PGET	$0	$0	$1,722,416	$0	$1,722,416
PWRX	$0	$0	$2,671	$0	$2,671
RVSD	$0	$14,866	$9,174	$0	$24,040
RWET	$0	$0	$4	$0	$4
SCE1	$53,528,608	$18,104,120	$2,834,050	$0	$74,466,778
SCE2	$0	$0	$127,511	$0	$127,511
SCE5	$0	$0	$31,292	$0	$31,292
SDG3	$0	$5,440,742	$1,620,706	$0	$7,061,448
SDGE	$0	$0	$0	$0	$0
SEES	$0	$2,142,049	$2,552,984	$0	$4,695,033
SEL1	$0	$2,094,216	$1,876,219	$0	$3,970,436
SETC	$0	$3,053	$1,114,067	$0	$1,117,120
SNCL	$0	$0	$4	$0	$4
SPPC	$0	$0	$4,110	$0	$4,110
SRP1	$0	$0	$322	$0	$322
TBEL	$0	$0	$322	$0	$322
TEMU	$0	$0	$1,158	$0	$1,158
VERN	$0	$361,448	$60,956	$0	$422,403
VSYN	$0	$373,049	$632,062	$0	$1,005,111
WAMP	$0	$273	$59,184	$0	$59,457
WDOE	$0	$167	$3,805	$0	$3,972
WEMT	$0	$0	$49,133	$0	$49,133
WEPA	$0	$1,294	$476	$0	$1,771
WESC	$0	$249	$407,258	$0	$407,507
WLMD	$0	$0	$14,873	$0	$14,873
WRDG	$0	$0	$7,247	$0	$7,247
Total	**$53,528,608**	**$32,865,859**	**$38,614,982**	**$0**	**$125,009,449**

EXHIBIT NO. ISO-11

MLCC Allocation for Operating Year 2003
Daily Allocation (South-Of-Lugo and Miguel Zonal)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
AEI1	$0	$0	$459	$0	$459
AEPS	$0	$0	$60	$0	$60
ANHM	$0	$10,817	$3,763	$0	$14,580
APS1	$0	$886,755	$369,077	$0	$1,255,833
APX1	$0	$198,855	$1,454,690	$0	$1,653,544
APX3	$0	$0	$2,220	$0	$2,220
APX4	$0	$0	$0	$0	$0
APX5	$0	$0	$0	$0	$0
AZUA	$0	$49,118	$10,431	$0	$59,548
BAN1	$0	$21,603	$7,723	$0	$29,327
CAL1	$0	$0	$2,121	$0	$2,121
CALP	$0	$593	$932,210	$0	$932,803
CDWR	$0	$621,053	$369,638	$0	$990,691
CECO	$0	$258,997	$288,719	$0	$547,716
CLTN	$0	$65,005	$133,841	$0	$198,846
CMWD	$0	$0	$12,024	$0	$12,024
CNCO	$0	$0	$11,866	$0	$11,866
COTB	$0	$3,148	$414,869	$0	$418,017
CPSC	$0	$0	$100	$0	$100
CRLP	$0	$70,193	$1,489,363	$0	$1,559,555
CTID	$0	$0	$9,280	$0	$9,280
DETM	$0	$0	$1,450,010	$0	$1,450,010
ECH1	$0	$0	$384,795	$0	$384,795
EMMT	$0	$0	$186,760	$0	$186,760
EPME	$0	$0	$8,252	$0	$8,252
FPPM	$0	$0	$0	$0	$0
GLEN	$0	$0	$0	$0	$0
HDPP	$0	$0	$454,597	$0	$454,597
IDAC	$0	$7,605	$7,386	$0	$14,992
MAEM	$0	$0	$106,189	$0	$106,189
MIRA	$0	$0	$1	$0	$1
MNEV	$0	$0	$452	$0	$452
MRNT	$0	$0	$218,362	$0	$218,362
MSCG	$0	$0	$150	$0	$150
MWSC	$0	$0	$32,305	$0	$32,305
NCPA	$0	$792	$80,705	$0	$81,497
NEI1	$0	$2,063,258	$1,744,100	$0	$3,807,358
NES1	$0	$0	$334,300	$0	$334,300
OPSI	$0	$0	$289,260	$0	$289,260
PAC1	$0	$0	$728	$0	$728
PASA	$0	$341,345	$63,315	$0	$404,660
PCG2	$0	$165,528	$11,358,259	$0	$11,523,786
PCGB	$0	$0	$1,920,799	$0	$1,920,799
PCPM	$0	$0	$276,833	$0	$276,833

MLCC Allocation for Operating Year 2003
Daily Allocation (South-Of-Lugo and Miguel Zonal)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
PETP	$0	$108	$85,540	$0	$85,647
PGAB	$0	$2,923	$270,778	$0	$273,701
PGET	$0	$0	$1,646,286	$0	$1,646,286
PWRX	$0	$0	$1,817	$0	$1,817
RVSD	$0	$11,192	$7,475	$0	$18,667
RWET	$0	$0	$3	$0	$3
SCE1	$53,528,608	$16,225,151	$2,810,118	$0	$72,563,877
SCE2	$0	$0	$107,211	$0	$107,211
SCE5	$0	$0	$27,811	$0	$27,811
SDG3	$0	$6,288,402	$1,791,416	$0	$8,079,819
SDGE	$0	$0	$0	$0	$0
SEES	$0	$2,358,068	$2,410,417	$0	$4,768,485
SEL1	$0	$2,325,595	$1,933,438	$0	$4,259,033
SETC	$0	$3,643	$1,138,199	$0	$1,141,842
SNCL	$0	$0	$3	$0	$3
SPPC	$0	$0	$5,950	$0	$5,950
SRP1	$0	$0	$151	$0	$151
TBEL	$0	$0	$177	$0	$177
TEMU	$0	$0	$1,768	$0	$1,768
VERN	$0	$396,662	$44,078	$0	$440,741
VSYN	$0	$382,897	$662,032	$0	$1,044,929
WAMP	$0	$219	$49,817	$0	$50,036
WDOE	$0	$0	$4,027	$0	$4,027
WEMT	$0	$0	$46,472	$0	$46,472
WEPA	$0	$1,018	$463	$0	$1,481
WESC	$0	$274	$379,462	$0	$379,736
WLMD	$0	$0	$18,039	$0	$18,039
WRDG	$0	$0	$6,084	$0	$6,084
Total	**$53,528,608**	**$32,760,817**	**$37,879,049**	**$0**	**$124,168,474**

EXHIBIT NO. ISO-12

MLCC Allocation for Operating Year 2003
Daily Allocation (South of Lugo and Miguel Local)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
AEI1	$0	$0	$459	$0	$459
AEPS	$0	$0	$60	$0	$60
ANHM	$0	$8,909	$3,763	$0	$12,672
APS1	$0	$645,365	$369,077	$0	$1,014,442
APX1	$0	$160,488	$1,454,690	$0	$1,615,177
APX3	$0	$0	$2,220	$0	$2,220
APX4	$0	$0	$0	$0	$0
APX5	$0	$0	$0	$0	$0
AZUA	$0	$37,361	$10,431	$0	$47,792
BAN1	$0	$17,278	$7,723	$0	$25,002
CAL1	$0	$0	$2,121	$0	$2,121
CALP	$0	$593	$932,210	$0	$932,803
CDWR	$0	$523,676	$369,638	$0	$893,314
CECO	$0	$180,865	$288,719	$0	$469,583
CLTN	$0	$48,122	$133,841	$0	$181,963
CMWD	$0	$0	$12,024	$0	$12,024
CNCO	$0	$0	$11,866	$0	$11,866
COTB	$0	$3,148	$414,869	$0	$418,017
CPSC	$0	$0	$100	$0	$100
CRLP	$0	$55,391	$1,489,363	$0	$1,544,754
CTID	$0	$0	$9,280	$0	$9,280
DETM	$0	$0	$1,450,010	$0	$1,450,010
ECH1	$0	$0	$384,795	$0	$384,795
EMMT	$0	$0	$186,760	$0	$186,760
EPME	$0	$0	$8,252	$0	$8,252
FPPM	$0	$0	$0	$0	$0
GLEN	$0	$0	$0	$0	$0
HDPP	$0	$0	$454,597	$0	$454,597
IDAC	$0	$5,846	$7,386	$0	$13,232
MAEM	$0	$0	$106,189	$0	$106,189
MIRA	$0	$0	$1	$0	$1
MNEV	$0	$0	$452	$0	$452
MRNT	$0	$0	$218,362	$0	$218,362
MSCG	$0	$0	$150	$0	$150
MWSC	$0	$0	$32,305	$0	$32,305
NCPA	$0	$792	$80,705	$0	$81,497
NEI1	$0	$1,599,784	$1,744,100	$0	$3,343,884
NES1	$0	$0	$334,300	$0	$334,300
OPSI	$0	$0	$289,260	$0	$289,260
PAC1	$0	$0	$728	$0	$728
PASA	$0	$258,507	$63,315	$0	$321,822
PCG2	$0	$165,299	$11,358,259	$0	$11,523,558
PCGB	$0	$0	$1,920,799	$0	$1,920,799
PCPM	$0	$0	$276,833	$0	$276,833

MLCC Allocation for Operating Year 2003
Daily Allocation (South of Lugo and Miguel Local)

SC	Local	Zonal	System (NNUD)	System (Dem/Exp)	Total
PETP	$0	$108	$85,540	$0	$85,647
PGAB	$0	$2,923	$270,778	$0	$273,701
PGET	$0	$0	$1,646,286	$0	$1,646,286
PWRX	$0	$0	$1,817	$0	$1,817
RVSD	$0	$6,437	$7,475	$0	$13,912
RWET	$0	$0	$3	$0	$3
SCE1	$59,987,789	$12,606,708	$2,810,118	$0	$75,404,615
SCE2	$0	$0	$107,211	$0	$107,211
SCE5	$0	$0	$27,811	$0	$27,811
SDG3	$882,154	$4,971,392	$1,791,416	$0	$7,644,962
SDGE	$0	$0	$0	$0	$0
SEES	$0	$1,767,485	$2,410,417	$0	$4,177,902
SEL1	$0	$1,741,433	$1,933,438	$0	$3,674,872
SETC	$0	$3,007	$1,138,199	$0	$1,141,205
SNCL	$0	$0	$3	$0	$3
SPPC	$0	$0	$5,950	$0	$5,950
SRP1	$0	$0	$151	$0	$151
TBEL	$0	$0	$177	$0	$177
TEMU	$0	$0	$1,768	$0	$1,768
VERN	$0	$307,904	$44,078	$0	$351,982
VSYN	$0	$299,245	$662,032	$0	$961,277
WAMP	$0	$219	$49,817	$0	$50,036
WDOE	$0	$0	$4,027	$0	$4,027
WEMT	$0	$0	$46,472	$0	$46,472
WEPA	$0	$966	$463	$0	$1,429
WESC	$0	$235	$379,462	$0	$379,697
WLMD	$0	$0	$18,039	$0	$18,039
WRDG	$0	$0	$6,084	$0	$6,084
Total	**$60,869,942**	**$25,419,483**	**$37,879,049**	**$0**	**$124,168,474**

EXHIBIT NO. ISO-13

Estimated MLCC Allocation for Operating Year 2004 - January 2004 through May 2004

		Local	Zonal	System (NNUD)	System (Demand/Export)	Total
South of. Lugo & Miguel as Local	Hourly	$59,939,124	$26,247,658	$1,494,625	$0	$87,681,407
	Daily	$59,939,124	$26,247,658	$1,514,692	$0	$87,701,473
	Monthly	$59,939,124	$26,256,403	$1,517,399	$0	$87,712,925
South of Lugo & Miguel as Zonal	Hourly	$59,845,980	$26,340,802	$1,494,625	$0	$87,681,407
	Daily	$59,845,980	$26,340,802	$1,514,692	$0	$87,701,473
	Monthly	$59,845,980	$26,340,802	$1,514,692	$0	$87,701,473

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official service list for the captioned proceeding, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California, on this 16th day of August, 2004.

Anthony J. Ivancovich BAM

Anthony J. Ivancovich